CHAPTER 7

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CHAPTER 7

INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control (I&C) systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment which constitute the protection system as defined in the Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

The primary purpose of the I&C systems is to provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady state and transient power operations (American Nuclear Society (ANS) Conditions I, II, III), and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). The ANS conditions are discussed in Chapter 15. Consequently, the information presented in this chapter emphasizes those I&C systems which are central to assuring that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as the U.S. Nuclear Regulatory Commission (USNRC) General Design Criteria (GDC) and IEEE Standards, concerned with the safe generation of nuclear power are met by these systems.

Definitions

Terminology used in this chapter is based on the definitions given in IEEE Standard 279-1971. In addition, the following definitions apply:

Degree of Redundancy: The difference between the number of channels monitoring a variable and the number of channels, which when tripped, will cause an automatic system trip.

Minimum Degree of Redundancy: The degree of redundancy below which operation is prohibited, or otherwise restricted, by the Technical Specifications.

Cold Shutdown Condition: When the reactor is subcritical by at least 1 percent $\Delta k/k$ and T_{avg} is ≤ 200°F.

Hot Standby Condition: When the reactor is subcritical by an amount greater than or equal to the margin to be specified in the applicable Technical Specification, and T_{avg} is greater than or equal to the temperature to be specified in the applicable Technical Specification.

Containment Isolation Phase A: Closure of all nonessential process lines which penetrate containment, initiated by the engineered safety features (ESF).

Containment Isolation Phase B: Closure of remaining process lines, initiated by containment Hi-3 pressure signal (process lines do not include ESF lines).

System Response Times

Reactor Trip System Response Time: The reactor trip system (RTS) response time shall be the time interval from when the monitored parameter exceeds its trip set point at the channel sensor until loss of voltage to the stationary gripper coils. Engineered Safety Features Actuation System Response Time: The interval required for the ESF sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed set points. The response time includes sensor/process (analog) and logic (digital) delay.

Reproducibility - This definition is taken from Scientific Apparatus Manufacturers Association (SAMA) Standard PMC-20.1-1973, Process Measurement and Control Terminology: The closeness of agreement among repeated measurements of the output for the same value of input, under normal operating conditions over a period of time, approaching from both directions. It includes drift due to environmental effects, hysteresis, long term drift, and repeatability. Long term drift (aging of components, etc) is not an important factor in accuracy requirements since, in general, the drift is not significant with respect to the time elapsed between testing. Therefore, long term drift may be eliminated from this definition. Reproducibility, in most cases, is a part of the definition of accuracy (described as follows):

Accuracy - This definition is derived from SAMA Standard PMC-20.1-1973. An accuracy statement for a device falls under Note 2 of the SAMA definition of accuracy, which means reference accuracy or the accuracy of that device at reference operation conditions: Reference accuracy includes conformity, hysteresis, and repeatability. To adequately define the accuracy of a system, the term reproducibility is useful as it covers normal operating conditions. The following terms, trip accuracy and indicated accuracy, etc, will then include conformity and reproducibility under normal operating conditions. Where the final result does not have to conform to an actual process variable but is related to another value established by testing, conformity may be eliminated, and the term reproducibility may be substituted, for accuracy.

Normal Operating Conditions: These conditions cover all normal process temperature and pressure changes. Also included are ambient temperature changes around the transmitter and racks. Accuracies under post-accident conditions are not included.

Readout Devices - For consistency, the final device of a complete channel is considered a readout device. This includes indicators, recorders, and controllers.

Channel Accuracy - This definition includes accuracy of primary element, transmitter, and rack modules. It does not include readout devices or rack environmental effects, but does include process and environmental effects on field-mounted hardware. Rack environmental effects are included in the next two definitions to avoid duplication due to dual inputs.

Indicated and/or Recorded Accuracy - This definition includes channel accuracy, accuracy of readout devices, and rack environmental effects.

Trip Accuracy - This definition includes comparator accuracy, channel accuracy for each input, and rack environmental effects. This is the tolerance expressed in process terms (percent or span) within which the complete channel must perform its intended trip function. This includes all instrument errors but no process effects, such as streaming. The term actuation accuracy may be used where the word trip might cause confusion (for example, when starting pumps and other equipment).

Control Accuracy - This definition includes channel accuracy, accuracy of readout devices (isolator, controller), and rack environmental effects. Where an isolator separates control and protection signals, the isolator accuracy is added to the channel accuracy to determine control accuracy, but credit is taken for tuning beyond this point, that is, the accuracy of these modules (excluding controllers) is included in the original channel accuracy. It is simply defined as the accuracy of the control signal in percent of the span of that signal. This will then include gain changes where the control span is different from the span of the measured variable. Where controllers are involved, the control span is the input span of the controller. No error is included for the time in which the system is in a nonsteady-state condition.

7.1.1 Identification of Safety-Related Systems

7.1.1.1 Safety-Related Systems

The instrumentation discussed in Chapter 7 that is credited in the accident analyses, and those needed to shut down Beaver Valley Power Station - Unit 2 (BVPS-2) safely are given in this section.

7.1.1.1.1 Reactor Trip System

The RTS is a functionally defined system described in Section 7.2. The equipment which provides the trip functions is also identified and discussed in Section 7.2. Design bases for the RTS are given in Section 7.1.2.1.1. Figure 7.1-1 includes a single line diagram of this system.

7.1.1.1.2 Engineered Safety Features Actuation System

The engineered safety features actuation system (ESFAS) is a functionally defined system described in Section 7.3. The equipment which provides the actuation functions is identified and discussed in Section 7.3. Design bases or the ESFAS are given in Section 7.1.2.1.2.

7.1.1.1.3 Instrumentation and Control Power Supply System

Design bases for the I&C power supply system are given in Section 7.1.2.1.3. Further description of this system is provided in Section 7.6.1.

7.1.1.2 Safety-Related Display Instrumentation

Display instrumentation provides the operator with information to enable him to monitor the results of ESF actions following a Condition II, III, or IV event. Table 7.5-1 identifies the safety-related display information.

7.1.1.3 Instrumentation and Control System Designers

All systems discussed in Chapter 7 have definitive functional requirements developed on the basis of the nuclear steam supply system (NSSS) design. All equipment necessary to achieve the functions shown on the logic diagrams, Figure 7.2-1, Sheets 1 through 18, are supplied by the NSSS, except where noted on the diagrams as being supplied by others.

7.1.1.4 Plant Comparison

System functions for all systems discussed in Chapter 7 are similar to those of the Beaver Valley Power Station - Unit 1. A comparison table is provided in Section 1.3.

7.1.2 Identification of Safety Criteria

Section 7.1.2.1 gives design bases for the safety-related systems given in Section 7.1.1.1. Design bases for nonsafety-related systems are provided in the sections which describe the systems. Conservative considerations for instrument errors are included in the accident analyses presented in Chapter 15. Functional requirements developed on the basis of the results of the accident analyses, which have utilized conservative assumptions and parameters, are used in designing these systems and a pre-operational testing program verifies the adequacy of the design. Accuracies are given in Sections 7.2, 7.3, and 7.5.

The criteria documents listed in Table 7.1-1 were considered in the design of the systems given in Section 7.1.1. In general, the scope of these documents is given in the document itself. This determines the systems or parts of systems to which the document is applicable. A discussion of compliance with each document for systems in its scope is provided in the referenced sections. Because some documents were issued after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

7.1.2.1 Design Bases

7.1.2.1.1 Reactor Trip System

The RTS acts to limit the consequences of Condition II events (faults of moderate frequency, such a loss of feedwater flow) by, at most, a shutdown of the reactor and turbine, with BVPS-2 capable of returning to operation after corrective action. The RTS features impose a limiting boundary region to BVPS-2 operation which ensures that the reactor safety limits are not exceeded during Condition II events and that these events can be accommodated without developing into more severe conditions. Reactor trip set points are given in Chapter 16, Technical Specifications.

The design requirements for the RTS are derived by analyses of BVPS-2 operating and fault conditions where automatic rapid control rod insertion is necessary in order-to prevent or limit core or reactor coolant boundary damage. The design bases addressed in Section 3 of IEEE Standard 279-1971 are discussed in Section 7.2.1. The design limits specified for the RTS are:

1. Minimum departure from nucleate boiling ratio shall not be less than 1.30 as a result of any anticipated transient or malfunction (Condition II faults).

2. Power density shall not exceed the rated linear power density for Condition II faults. Chapter 4 describes fuel design limits.

3. The stress limit of the reactor coolant system for the various conditions shall not be exceeded as specified in Chapter 5.

4. Release of radioactive material shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius as a result of any Condition III fault.

5. For any Condition IV fault, release of radioactive material shall not result in an undue risk to public health and safety.

7.1.2.1.2 Engineered Safety Features Actuation System

The ESFAS acts to limit the consequences of Condition III events (infrequent faults such as primary coolant leakage from a small rupture which exceeds normal charging system makeup and requires actuation of the safety injection system). The ESFAS acts to mitigate Condition IV events (limiting faults, which include the potential for significant release of radioactive material).

The design bases for the ESFAS are derived from the design bases given in Chapter 6 for the ESF. Design bases requirements of Section 3 of IEEE Standard 279-1971 are addressed in Section 7.3.1.2. General design requirements are as follows:

1. Automatic actuation requirements

   The primary requirement of the ESFAS is to receive input signals (information) from the various processes within the reactor plant and containment and automatically provide, as output, timely and effective signals to actuate the various components and subsystems comprising the ESF system.

2. Manual actuation requirements

   The ESFAS has provisions in the main control room for manually initiating the functions of the ESF.

7.1.2.1.3 Instrumentation and Control Power Supply System

The I&C power supply system provides continuous, reliable, regulated single-phase ac power to all I&C equipment required for plant safety. Details of this system are provided in Section 7.6. The design bases are given as follows:

1. Each inverter has the capacity and regulation required for the ac output for proper operation of the equipment supplied.

2. Redundant loads are assigned to different distribution panels which are supplied from different inverters.

3. Auxiliary devices that are required to operate dependent equipment are supplied from the same distribution panel to prevent the loss of electric power in one protection set from causing the loss of equipment in another protection set. No single failure shall cause a loss of power supply to more than one distribution panel.

4. Each of the distribution panels has access only to its respective inverter supply and a standby power supply.

5. The system complies with IEEE Standard 308-1974, Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, Paragraph 5.4.

7.1.2.1.4 Emergency Power

Design bases and system description for the emergency power supply is provided in Chapter 8.

7.1.2.1.5 Interlocks

Interlocks are discussed in Sections 7.2, 7.3, 7.6, and 7.7. The protection (P) interlocks for reactor trip and ESFAS are given in Tables 7.2-2 and 7.3-3. The safety analyses demonstrate that even under conservative critical conditions for either postulated or hypothetical accidents, the protective systems ensure that the NSSS will be put into and maintained in a safe state following an ANS Condition II, III, or IV accident commensurate with applicable Technical Specifications and pertinent ANS criteria. Therefore, the protective systems have been designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks. All blocks of a protective function are automatically cleared whenever the protective function would be required to function in accordance with GDC 20, 21, and 22 and Paragraphs 4.11, 4.12, and 4.13 of IEEE Standard 279-1971. Control interlocks (C) are identified in Table 7.7-1. Because control interlocks are not safety-related, they have not been specifically designed to meet the requirements of IEEE protection system standards.

7.1.2.1.6 Bypasses

Bypasses are designed to meet the requirements of IEEE Standard 279-1971, Paragraphs 4.11, 4.12, 4.13, and 4.14. A discussion of bypasses provided is given in Sections 7.2 and 7.3.

7.1.2.1.7 Equipment Protection

The criteria for equipment protection are given in Chapter 3. Equipment related to safe operation of BVPS-2 is designed, constructed, and installed to protect it from damage. This is accomplished by working to accepted standards and criteria aimed at providing reliable instrumentation that is available under varying conditions. As an example, certain equipment is seismically qualified in accordance with IEEE Standard 344-1975, Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations. During construction, independence and separation are achieved, as required by IEEE Standards 279-1971 and 384-1974, Criteria for Independence of Class 1E Equipment and Circuits, and Regulatory Guide 1.75, either by barriers or physical separation or by analysis or test. This serves to protect against complete destruction of a system by fires, missiles, or other natural hazards.

7.1.2.1.8 Diversity

Functional diversity has been designed into the ESFAS and the RTS. Functional diversity is discussed by Gangloff and Loftus (1971). The extent of diverse system variables has been evaluated for a wide variety of postulated accidents.

For example, there are automatic reactor trips based upon neutron flux measurements, reactor coolant temperature and flow measurements, pressurizer pressure and level measurements, steam generator feedwater flow and level measurements, and reactor coolant pump (RCP) underfrequency and undervoltage measurements, as well as manually, and by initiation of a safety injection signal.

Regarding the ESFAS for a loss-of-coolant accident, a safety injection signal can be obtained manually or by automatic initiation from two diverse parameter measurements.

1. Low pressurizer pressure.

2. High containment pressure (Hi-1).

For a steam line break accident, diversity of safety injection signal actuation is provided by:

1. Low compensated steam line pressure.

2. For a steam break inside containment, high containment pressure (Hi-1) provides an additional parameter for generation of the signal.

3. Low pressurizer pressure.

All of the preceding sets of signals are redundant and physically separated and meet the requirements of IEEE Standard 279-1971.

7.1.2.1.9 Trip Set Points

The guidelines of Regulatory Guide 1.105 are followed with the clarification described as follows: The protection system will automatically initiate appropriate protective action whenever a condition monitored by the system reaches a preset condition or set point.

Three groups of values are used in determining reactor trip and ESF actuation set points.

The first group of values will be the safety analysis limits assumed in the accident analysis (Chapter 15). These will be the least conservative values.

The second group will consist of limiting values as listed in Chapter 16, Technical Specifications. These will be the maximum/minimum allowable values for limiting safety system settings and limiting conditions for operation. Limiting values will be obtained by subtracting a safety margin from the safety analysis values. The safety margin will account for instrument error, calibration uncertainties, and process uncertainties, such as flow stratification and transport factor effects, etc.

The third group will consist of the nominal values set into the equipment. These values will be obtained by subtracting allowances for instrument drift from the limiting values. The nominal values will allow for normal expected instrument set point drift such that the Technical Specification allowable values will not be exceeded under normal operation. These values are given in the trip set points in Chapter 16.

As illustrated previously, the trip set point will be determined by factors other than the most accurate portion of the instrument's range. The only requirement on the instrument's accuracy value is that over the instrument span, and the error must always be less than or equal to that assumed in the accident analysis. The instrument does not need to be the most accurate at the trip set point value as long as it meets the minimum accuracy requirements.

Range selection for the instrumentation will cover the expected range of the process variable being monitored, consistent with its application. The design of the protection system will be such that trip set points will not require process transmitters to operate within 5 percent of the high and low ends of their calibrated span or range. Functional requirements established for every channel in the protection system stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels will have the capability for and will be tested to ascertain that the characteristics throughout the entire span are acceptable, and meet the functional requirements specifications.

In this regard, it should be noted that specific functional requirements for response time, set point, and operating span will be finalized contingent on the results and evaluation of safety studies to be carried out using data pertinent to BVPS-2. Emphasis will be placed on establishing adequate performance requirements under both normal and faulted conditions. This will include consideration of process transmitter margins such that even under a highly improbable situation of full power operation at the safety analysis limits, that adequate instrumentation response is available to ensure plant safety.

7.1.2.1.10 Engineered Safety Features Motor Specifications

Motors are discussed in Section 8.3.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety-related systems in Section 7.1.1.1 are designed to meet the independence requirements of GDC 22 and Paragraph 4.6 of IEEE Standard 279-1971.

The electrical power supply, instrumentation, and control conductors for redundant circuits of BVPS-2 have physical separation to preserve the redundancy and to ensure that no single credible event will prevent operation of the associated function due to electrical conductor damage. Critical circuits and functions include power, control, and analog instrumentation associated with the operation of the RTS or ESFAS. Credible events include, but are not limited to, the effects of short circuits, pipe rupture, missiles, fire, etc, and are considered in the basic BVPS-2 design.

7.1.2.2.1 General (Including Regulatory Guide 1.75 and IEEE Standard 384-1974)

Description of separation is provided in Section 8.3.

The physical separation criteria for redundant safety-related system sensors, sensing lines, wireways, cables, and components on racks within the NSSS scope meet recommendations contained in Regulatory Guide 1.75, with the following comments:

The core thermocouple system satisfies Regulatory Guide 1.75 separation requirement except for the two channels/trains inside the refueling cavity. The method of installation of the core thermocouples within the reactor cavity was completed prior to upgrading of the system to satisfy Regulatory Guide 1.97 requirements. The design within the refueling cavity is acceptable because:

1. Only a small self-generated signal exists in the cabling from the thermocouples to the reference junction boxes and therefore no chance exists for a postulated propagating fault, and

2. Due to the interference provided by the rod control mechanisms and rod position indicator stack, no likelihood exists for rendering all thermocouples inoperable.

Separation recommendations for redundant instrumentation racks are not the same as those given in Paragraph C-16 of Regulatory Guide 1.75 for the main control boards because of different functional requirements. Main control boards contain redundant circuits which are required to be physically separated from each other. However, since there are no redundant circuits which share a single compartment of an NSSS protection instrumentation rack, and since these redundant protection instrumentation racks are physically separated from each other, the physical separation requirements specified for the main control board do not apply.

To demonstrate the adequacy of the designs, test programs were conducted to supplement the isolator verification tests in order to assess any effects due to the manner in which isolators were wired in the protection cabinets.

The programs demonstrated that Class 1E protection systems: nuclear instrumentation system (NIS), solid state protection system (SSPS), and 7300 process control system (PCS) are not degraded by non-Class 1E circuits sharing the same enclosure. Conformance to the requirements of IEEE Standard 279-1971 and Regulatory Guide 1.75 has been established and accepted by the USNRC based on the following, which is applicable to these systems at BVPS-2.

Tests conducted on the as-built designs of the NIS and SSPS were reported and accepted by the USNRC in support of the Diablo Canyon application (Docket Nos. 50-275 and 50-323). These programs are applicable to BVPS-2. Tests on the 7300 PCS are covered in the report entitled 7300 Series Process Control System Noise Tests subsequently reissued as WCAP-8892-A (Siroky and Marasco 1977). In a letter dated April 20, 1977, R. Tedesco to C. Eicheldinger, the USNRC accepted the report in which the applicability of BVPS-2 is established. Tests were conducted on the Eagle 21 Family of equipment of which the PSMS is included. The results of the testing are described in detail in WCAP-11340, "Noise, Fault, Surge and Radio Frequency Interference Test Report" same subject (Non-Proprietary). These WCAPs were officially submitted to the NRC on the South Texas Docket.

7.1.2.2.2 Specific Systems

Independence is maintained through the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters.

Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant protection channel set. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant channel set is energized from a separate ac power source.

There are four separate process analog sets. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and analog protection cabinets to the redundant trains in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

In the NIS, 7300 PCS, and the SSPS input cabinets, where redundant channel instrumentation are physically adjacent, there are no wireways or cable penetrations which would permit, for example, a fire resulting from electrical failure in one channel to propagate into redundant channels in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

Independence of the logic trains is discussed in WCAP-7672 (Katz 1971). Two reactor trip breakers are actuated by two separate logic matrices which interrupt power to the control rod drive mechanisms.

The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all CRDMs, permitting the rods to free fall into the core.

1. Reactor trip system

    a. Separate routing is maintained for the four basic RTS channel sets analog sensing signals, bistable output signals, and power supplies for such systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

    b. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets is maintained, and in addition, they are separated by spatial separation or by provision of barriers or by separate cable trays or wireways from the four analog channel sets.

2. Engineered safety features actuation system

    a. Separate routing is maintained for the four basic sets of ESFAS analog sensing signals, bistable output signals, and power supplies for such systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

b. Separate routing of the ESF actuation signals from the redundant logic system cabinets is maintained. In addition, they are separated by spatial separation or by provisions of barriers or by separate cable trays or wireways from the four analog channel sets.

c. Separate routing of control and power circuits associated with the operation of ESF equipment is required to retain redundancies provided in the system design and power supplies.

3. Instrumentation and control power supply system

   The separation criteria presented also apply to the power supplies for the load centers and buses distributing power to redundant components and to the control of these power supplies (Section 8.3).

The RTS and ESFAS analog circuits may be routed in the same wireways provided circuits have the same power supply and channel set identified (I, II, III, or IV).

7.1.2.2.3 Fire Protection

For electrical equipment within the NSSS scope of supply, Westinghouse specifies noncombustible or fire retardant material and conducts vendor-supplied specification reviews of this equipment, which includes assurance that materials will not be used which may ignite or explode from an electrical spark, flame, or from heating, or will independently support combustion. These reviews also include assurance of conservative current carrying capacities of all instrument cabinet wiring, which precludes electrical fires resulting from excessive overcurrent (I^2R) losses. For example, wiring used for instrument cabinet construction has teflon or tefzel insulation and will be adequately sized based on current carrying capacities set forth by the National Electrical Code. Braided sheathed material is noncombustible. BVPS-2 fire protection is described in Section 9.5.1.

7.1.2.3 Physical Identification of Safety-Related Equipment

There are four separate protection sets identifiable with process equipment associated with the RTS and ESFAS. A protection set may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and equipment cabinets to the redundant trains in the logic racks. The SSPS input cabinets are divided into four isolated compartments, each serving one of four redundant input channels. Horizontal 1/8-inch thick solid steel barriers, coated with fire retardant paint, separate the compartments. Four 1/8-inch thick solid steel, vertical wireways coated with fire retardant paint enter the input cabinets. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks, the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The color coded nameplates described as follows provide identification of equipment associated with protective functions and their channel set association:

Channel	Color Coding
I	Red with white lettering
II	White with black lettering
III	Blue with white lettering
IV	Yellow with black lettering

All noncabinet-mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components, such as relays, have nameplates on the enclosure which houses them. All cables are numbered with identification tags. Section 8.3 discusses cables, cable trays, and conduit.

7.1.2.4 Requirements for Periodic Testing

Periodic testing of the RTS and ESFAS is described in Sections 7.2.2 and 7.3.2. Testing complies with Regulatory Guide 1.22 and IEEE Standard 338-1977, Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems.

The surveillance requirements of the Technical Specifications ensure that the system functional operability will be maintained comparable to the original design standards. Periodic testing shall be conducted at the intervals specified in Technical Specifications for reactor trip, for ESF actuation, and for post-accident monitoring. Sensors will be demonstrated adequate for the design by test reports, analysis, operating experience, or by suitable type testing. The NIS detectors are excluded since delays attributable to them do not constitute a significant portion of the overall channel response.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main control room by a separate annunciator for the train in test. Test circuitry does not allow two trains to be tested at the same time so that extension of the bypass condition to the redundant system is prevented.

The actuation logic for the RTS and ESFAS is tested as described in Sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation, it has been determined that:

1. There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of BVPS-2,

2. The probability that the protection system will fail to initiate operation of the equipment is and can be maintained acceptably low without testing the equipment during reactor operation, and

3. The equipment can routinely be tested when the reactor is shut down.

The equipment that cannot be tested at full power so as not to damage equipment or upset plant operation are:

1. Manual actuation switches for system level actuation of protective function,

2. Reactor coolant pump circuit breakers,

3. Turbine trip,

4. Main steam line isolation valves (close),

5. Main feedwater isolation valves (close),

6. Feedwater control valves (close),

7. Reactor coolant pump primary component cooling water isolation valves (close),

8. Main feedwater pump trip,

9 Reactor coolant pump seal water return valves (close),

10. Main generator trip,

11. Primary component cooling to containment, and

12. "Miscellaneous"

The justification for not testing these items at full power is discussed as follows:

1. Manual actuation switches

   Testing of these at full power would cause initiation of their protection system function, causing plant upset and/or reactor trip. It should be noted that the reactor trip function that is derived from the automatic safety injection signal is tested at power as follows:

   The analog signals, from which the automatic safety injection signal is derived, is tested at power in the same manner as the other analog signals and as described in Section 7.2.2.2.3 (10). The processing of these signals in the SSPS, wherein their channel orientation converts to a logic train orientation, is tested at power by the built-in semi-automatic test provisions of the SSPS. The reactor trip breakers are tested at power, as discussed in Section 7.2.2.2.3 (10).

2. Reactor coolant pump circuit breakers

   No credit is taken in the accident analyses for an RCP breaker opening causing a reactor trip. Since testing them at power would cause a plant upset, the RCP breakers do not need to be tested at power.

3. Turbine trip

   The generation of reactor trip from turbine trip is a testable function at power [similar to the other reactor trip generated from analog channels developing a bistable (on-off) output] as follows:

   a. The signal derived from the trip fluid pressure switch may be testable at power by exercising the switches one at a time by means of observance of BVPS-2 operating procedures at full power.

   b. The position signal derived from the turbine steam stop valves is testable at reduced load by means of observance of BVPS-2 operating procedures when the functional tests of the steam inlet valves is performed at a one-valve-at-a-time basis.

4. Main steam line isolation valves

   Main steam line isolation valves (MSIVs) are routinely tested during refueling outages. Testing of the MSIVs to closure at power is not practical. As the plant power is increased, the coolant average temperature is programmed to increase. If the valves are closed under these elevated temperature conditions, the steam pressure transient would unnecessarily operate the steam generator relief valves and possibly the steam generator safety valves. The steam pressure transient produced would cause shrinkage in the steam generator level, which would cause the reactor to trip on low-low generator water level. Testing during operation will decrease the operating life of the valve.

   Based on the previously identified problems incurred with periodic testing of the MSIVs at power, and since 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of BVPS-2, 2) the probability that the protection system will fail to initiate the actuated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

5. Main feedwater isolation valves

The feedwater isolation valves are routinely tested during refueling outages. Periodic testing of these feedwater isolation valves by closing them completely, or partially, at power would induce steam generator water level transients and oscillations which would trip the reactor. These transient conditions would be caused by perturbing the feedwater flow and pressure conditions necessary for proper operation of the steam generator water level control system.

Based on these identified problems incurred with periodic testing of the feedwater isolation valves at power, and since 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of BVPS-2, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

6. Feedwater control valves

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of BVPS-2. The verification of operability of feedwater control valves at power is assured by confirmation of proper operation of the steam generator water level system. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these control valves is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the de-energize-to-actuate principle so that the feedwater control valves will fail closed upon either the loss of electrical power to the solenoids or loss of air pressure.

Based on the preceding, the testing of the isolating function of feedwater control valves meets the guidelines of Section D.4 of Regulatory Guide 1.22.

7. Reactor coolant pump primary component cooling water isolation valves (close)

The primary component cooling water (PCCW) supply and return containment isolation valves are routinely tested during refueling outages. Testing of these valves while the RCPs are operating introduces an unnecessary risk of costly damage to all the RCPs. Loss of PCCW to these pumps is of economic consideration only, as the RCPs are not required to perform any safety-related function.

The RCPs will not seize due to complete loss of component cooling water. Information from the pump manufacturer indicates that the bearing babbitt would eventually break down but not so rapidly as to overcome the inertia of the flywheel. If the pumps are not stopped within approximately 10 minutes after PCCW is isolated, pump damage could be incurred.

Additional containment penetrations and containment isolation valves introduce additional unnecessary potential pathways for radioactive leakage following a postulated accident. Also, since the PCCW flow rates and temperatures are about equal during both plant power operation and plant refueling, periodic tests of these valves during a refueling outage would duplicate accident conditions. Additionally, possibility of failure of containment isolation is remote because an additional failure of the low pressure fluid system, in addition to failure of both isolation valves, would have to occur to open a path through the containment.

Based on the previously described potential RCP damage incurred with periodic testing of the PCCW containment isolation valves at power, the duplication of at-power operating conditions during refueling outages, and since 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of BVPS-2, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages when the RCPs are not operating, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

8. Main feedwater pump trip

No credit is taken in the analysis for tripping the main feedwater pumps and therefore, this function does not require periodic testing. These functions are routinely tested during refueling outages.

9. Reactor coolant pump seal water return valves

Seal water return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the safety valve to lift, with the possibility of valve chatter. Valve chatter would damage this relief valve so testing of these return line isolation valves at power would cause equipment damage. Therefore, these valves will be tested during scheduled refueling outages. As mentioned previously, additional containment penetrations and containment isolation valves introduce additional unnecessary potential pathways for radioactive release following a postulated accident. Thus, the guidelines of Section D.4 of Regulatory Guide 1.22 are met.

10. Main generator trip

    The main generator trip cannot be actuated during BVPS-2 operation without causing plant upset or equipment damage. Circuitry for these devices has been provided to individually block actuation of a final device upon operation of the associated solid state logic output relay during testing. Operation of the output relay, including its contact operation and continuity of the electrical circuit associated with the final devices control, is checked in lieu of actual operation. Interlocking prevents blocking the output from more than one output relay in a protection train at a time. Interlocking between trains is also provided to prevent continuity testing in both trains simultaneously. Therefore, the redundant device associated with the protection train not under test will be available in event protection action is required.

11. Primary component cooling to containment

    The PCCW containment isolation valves are required to perform a containment isolation function and will be leak-tested and exercised in accordance with the requirements of 10 CFR 50 Appendix J. These valves cannot be full-stroked or leak-tested during BVPS-2 operation. Closing of any of these valves would result in a loss of cooling water to one or two RCPs. These valves will be full-stroked and leak-tested during cold shutdown conditions, utilizing the leakage monitoring connections provided, in accordance with 10 CFR 50 Appendix J, Type C testing requirements.

12. "Miscellaneous"

    License Amendment No. 147 revised Technical Specifications to eliminate periodic response time testing requirements on selected sensors and selected protection channel components. The Amendment permits the option of either measuring or verifying the response times by means other than testing.

    The NRC staff stipulated conditions in their Safety Evaluation related to License Amendment No. 147. Two of the conditions were not applicable at the time the License Amendment was issued but may be applicable in the future if the plant is modified. The staff conditions and licensee response are described below to ensure future modification of

    a Unit 2 Reactor Trip System or Engineered Safety Feature Actuation System pressure sensor (pressure or differential pressure transmitter) which requires response time verification will satisfy the two conditions.

    Condition

    For transmitters and switches that use capillary tubes, perform a response time test after initial installation and after any maintenance or modification activity that could damage the capillary tubes.

Commitment

BVPS Unit 2 has no pressure sensors (transmitters or switches) that use capillary tubes in any Reactor Trip System (RTS) or Engineered Safety Features Actuation System (ESFAS) application for which periodic response time testing is required. If BVPS Unit 2 replaces any RTS or ESFAS pressure sensors for which response time verification is required in the future with sensors using capillary tubes, then BVPS Unit 2 will implement plant procedure changes (and/or other appropriate administrative controls) to assure the sensors are response time tested after initial installation and after any maintenance or modification activity that could damage the capillary tubes.

This commitment must be met prior to the application of WCAP-13632 methodology for the associated sensor.

Condition

If variable damping is used, implement a method to assure that the potentiometer is at the required setting and cannot be inadvertently changed or perform hydraulic response time testing of the sensor following each calibration.

Commitment

BVPS Unit 2 has no pressure transmitters with variable damping installed in any RTS or ESFAS application for which response time testing is required. If BVPS Unit 2 replaces any RTS or ESFAS pressure transmitters for which response time verification is required in the future with pressure transmitters which have variable damping capability, then BVPS Unit 2 will implement procedure changes and/or establish appropriate administrative controls to assure the variable damping potentiometer cannot be inadvertently changed. This commitment must be met prior to the application of WCAP-13632 methodology for the associated transmitter.

7.1.2.5 Conformance to Regulatory Guide 1.47

Bypass/inoperability indication is in agreement with Regulatory Guide 1.47 with the following clarification:

1. An indicator of bypass/inoperability will be provided for redundant or diverse portions of each safety system. (Bypass includes any deliberate action which renders a safety system inoperable.)

2. Only permanently installed electrical control devices in accessible locations are considered for bypassing a safety

system. The term permanently installed does not include the portable handle required to rack out a circuit breaker or devices within the containment which are not considered accessible. The term control devices applies to equipment intended to be acted upon by an operator, such as control switches. It does not include equipment which might be manipulated by prodding, such as relays.

System level bypass and inoperability status, in accordance with Regulatory Guide 1.47, is discussed in Section 7.5.

7.1.2.6 Conformance to Regulatory Guide 1.53 and IEEE Standard 379-1972

The principles described in IEEE Standard 379-1972, Application of the Single Failure Criterion to Nuclear Power Generating Station Class 1E Systems, were used in the design of the protection system. The system complies with the intent of this standard and the additional guidance of Regulatory Guide 1.53. The formal analyses have not been documented exactly as outlined, although parts of such analyses are published in various documents, such as the fault tree analysis, WCAP-7706, by Gangloff and Loftus (1971).

The referenced topical report provides details of the analyses of the protection systems previously made to show conformance with single failure criterion set forth in Paragraph 4.2 of IEEE Standard 279-1971. The interpretation of single failure criterion provided by IEEE Standard 379-1972 does not indicate substantial differences with the interpretation of the criterion, except in the methods used to confirm design reliability. Established design criteria, in conjunction with sound engineering practices, form the bases for the protection systems. The RTS and ESFAS are each redundant safety systems. The required periodic testing of these systems will disclose any failures or loss of redundancy which could have occurred in the interval between tests, thus ensuring the availability of these systems.

Protection system design conforms to Regulatory Guide 1.53 and IEEE Standard 379-1972, as interpreted as follows: The required failure modes and effects analyses analyze the channel power supplies, the balance of plant protection system logic, and the actuator system, as addressed in Section 7.3.2.

1. As stated in Position C.1 of Regulatory Guide 1.53, due to the trial use status of source document IEEE Standard 379-1972, departure from certain provisions may occur.

2. With regard to Position C.2 of Regulatory Guide 1.53, the protection system, as defined by IEEE Standard 279-1971, incorporates the capabilities for test and calibration as set forth in Paragraphs 4.9 and 4.10 of IEEE Standard 279-1971.

   Final actuation devices, as defined by IEEE Standard 379-1972, are capable of periodic testing in accordance with Regulatory Guide 1.22. The final actuation devices which cannot be fully tested during reactor operation (for reasons as stated in

Positions 4.a through 4.c of Regulatory Guide 1.22) can be subjected to a partial test with the unit on-line and to full operational testing during reactor shutdown. These devices are tested and discussed in Section 7.1.2.4.

Taken as a whole, the operability of all active components necessary to achieve protective functions can be demonstrated via the testing program described in this item.

3. With regard to Position C.3 of Regulatory Guide 1.53, single switches supplying signals to redundant channels are designed with at least 6 inches separation or suitable barriers between redundant circuits.

4. Compliance with the single failure criteria can be verified based on a collective analysis of both the protective system defined in IEEE Standard 279-1971 and the final actuation devices or actuators defined in IEEE Standard 379-1972.

7.1.2.7 Conformance to Regulatory Guide 1.63

Conformance to Regulatory Guide 1.63 is discussed in Section 8.3.

7.1.2.8 Conformance to IEEE Standard 317-1976

Conformance to IEEE Standard 317-1976, Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations, is discussed in Section 8.3.

7.1.2.9 Conformance to IEEE Standard 336-1971

The quality assurance requirements for installing, inspecting, and testing for instrumentation and electric equipment conforms to IEEE Standard 336-1971.

7.1.2.10 Conformance to IEEE Standard 338-1977

The periodic testing of the RTS and ESFAS conforms to the requirements of IEEE Standard 338-1977, with the following comments:

1. The surveillance requirements of the Technical Specifications for protection system ensure that the system functional operability is maintained comparable to the original design standards. Periodic tests at frequent intervals or verifications demonstrate this capability for the system, excluding sensors.

   Sensors within the Westinghouse scope will be demonstrated adequate for this design by vendor testing, onsite tests in operating plants with appropriately similar design, by suitable type testing, or verification. The NIS detectors are excluded since they exhibit response time characteristics such that delays attributable to them are negligible in the overall channel response time required for safety.

Overall protection system response times are verified in accordance with the Technical Specifications.

The verification of response times provides assurance that the protective and ESF action function associated with each channel is completed within the time limit assumed in the accident analysis.

2. Reliability goals in accordance with the program mentioned in Section 4 of IEEE Standard 338-1977 have been developed, and adequacy of time intervals has been demonstrated.

3. The periodic test interval as specified in the BVPS-2 Technical Specifications and following the guidance of Section 4, of IEEE Standard 338-1977, is conservatively selected to assure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to BVPS-2 condition changes, the time interval will be decreased to accommodate the situation until the marginal performance is resolved.

7.1.3 References For Section 7.1

Gangloff, W. C. and Loftus, W. D. 1971. An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients. WCAP-7706.

Katz, D. N. 1971. Solid State Logic Protection System Description. WCAP-7488-L (Proprietary) and WCAP-7672.

Siroky, R. M. and Marasco, F. W. 1977. 7300 Series Process Control System Noise Tests. WCAP-8892-A.

Tables for Section 7.1

TABLE 7.1-1

LISTING OF APPLICABLE CRITERIA

Criteria	Title	Discussed In
1. General Design Criteria (GDC), 10 CFR 50, Appendix A		
GDC 1	Quality Standards and Records	3.1.2, Chapters 7, 17
GDC 2	Design Bases for Protection Against Natural Phenomena	3.1.2, 3.10, 3.11, 7.2.1.1.11
GDC 3	Fire Protection	3.1.2, 7.1.2.2.3, 9.5
GDC 4	Environmental and Missile Design Bases	3.1.2, 3.11, 7.2.2.2
GDC 5	Sharing of Structures, Systems, and Components	3.1.2
GDC 10	Reactor Design	3.1.2, 7.2.2.2
GDC 12	Suppression of Reactor Power Oscillations	3.1.2, 7.7, Chapter 15
GDC 13	Instrumentation and Control	3.1.2, 7.3.1, 7.3.2, 7.7
GDC 15	Reactor Coolant System Design	3.1.2, 7.2.2.2
GDC 17	Electric Power Systems	3.1.2, 7.2.2.2, 7.6, Chapter 8
GDC 19	Control Room	3.1.2, 7.4.1.3, 7.7
GDC 20	Protection System Functions	3.1.2, 7.2, 7.3, 7.5
GDC 21	Protection System Reliability and Testability	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC 22	Protection System Independence	3.1.2, 7.1.2.2, 7.2.2.2, 7.3.1, 7.3.2
GDC 23	Protection System Failure Modes	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC 24	Separation of Protection and Control Systems	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC 25	Protection System Requirements for Reactivity Control Malfunctions	3.1.2, 7.3.2

TABLE 7.1-1 (Cont)

Criteria	Title	Discussed In
GDC 26	Reactivity Control System Redundancy and Capability	3.1.2
GDC 27	Combined Reactivity Control Systems Capability	3.1.2, 7.3.1, 7.3.2, 7.7, Chapter 15
GDC 28	Reactivity Limits	3.1.2, 7.3.1, 7.3.2, 7.7, Chapter 15
GDC 29	Protection Against Anticipated Operational Occurrences	3.1.2, 7.2.2.2
GDC 33	Reactor Coolant Makeup	3.1.2
GDC 34	Residual Heat Removal	3.1.2
GDC 35	Emergency Core Cooling	3.1.2, 7.3.1, 7.3.2
GDC 37	Testing of Emergency Core Cooling System	3.1.2, 7.3.2
GDC 38	Containment Heat Removal	3.1.2, 7.3.1, 7.3.2
GDC 40	Testing of Containment Heat Removal System	3.1.2, 7.3.2
GDC 41	Containment Atmosphere Cleanup	3.1.2, 7.3.2
GDC 43	Testing of Containment Atmosphere Cleanup Systems	3.1.2, 7.3.2
GDC 44	Cooling Water	3.1.2
GDC 46	Testing of Cooling Water System	3.1.2, 7.3.2
GDC 50	Containment Design Basis	3.1.2
GDC 54	Piping Systems Penetrating Containment	3.1.2
GDC 55	Reactor Coolant Pressure Boundary Penetrating Containment	3.1.2
GDC 56	Primary Containment Isolation	3.1.2

TABLE 7.1-1 (Cont)

Criteria	Title	Discussed In
GDC 57	Closed System Isolation Valves	3.1.2
2. Institute of Electrical and Electronics Engineers (IEEE) Standards:		
IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations	7.1, 7.2, 7.3, 7.4, 7.5, 7.6
IEEE Std 308-1971, 1974	Criteria for Class 1E Power Systems for Nuclear Power Generating Stations	8.1 for 1971 and 7.6, 8.1, 8.2.1.4.4, 8.3.1.1.15 for 1974
IEEE Std 317-1976	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations	Chapter 8
IEEE Std 323-1971, 1974	Qualifying Class 1E Equipment for Nuclear Power Generating Stations	3.10, 3.11*
IEEE Std 336-1971 (ANSI N45.2.4-1972)	Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations	7.1.2.9
IEEE Std 338-1977	Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems	7.1.2.4, 7.1.2.10, 7.2.2, 7.3.2
IEEE Std 344-1971, 1975	Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations	3.10B
IEEE Std 379-1972 (ANSI N41.2)	Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems	7.1.2.6
IEEE Std 382-1972, 1980	Type Test of Class 1 Electric Valve Operators	3.9*
IEEE Std 384-1974 (ANSI N41.14)	Criteria for Separation of Class 1E Equipment and Circuits	7.1.2.2.1, 7.1.2.2.2

TABLE 7.1-1 (Cont)

Criteria	Title	Discussed In
IEEE Std 334-1974	Standard for Type Tests of Continuous Duty Class Motors Installed Inside the Containment of Nuclear Generating Stations	8.1, 8.3.1
3. Regulatory Guides (RG)		
RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems	1.8, 7.6, Chapter 8
RG 1.11	Instrument Lines Penetrating Primary Reactor Containment	1.8, 6.2.4, 7.3.1.1.2
RG 1.22	Periodic Testing of Protection System Actuation Functions	1.8, 7.1.2.4, 7.2.2.2.3, 7.3.2.2.5, 8.3.1, 8.3.2
RG 1.29	Seismic Design Classification	1.8, 3.2.1
RG 1.30	Quality Assurance Requirements for the Installation, Inspections, and Testing of Instrumentation and Electric Equipment	1.8, 8.3.1, 8.3.2, Chapter 17
RG 1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants	1.8, 7.5, 7.6, 8.2, 8.3.1, 8.3.2
RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	1.8, 7.1.2.5, 7.5, 8.2, 8.3
RG 1.53	Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems	1.8, 3.1.1, 7.1.2.6, 15.0.8
RG 1.62	Manual Initiation of Protective Actions	1.8, 7.2.2.2.3, 7.3.2.2.7
RG 1.63	Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants	1.8, 8.3
RG 1.68	Initial Test Programs for Water-Cooled Nuclear Power Plants	1.8, Chapter 14

TABLE 7.1-1 (Cont)

Criteria	Title	Discussed In
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants	1.8, Chapter 7
RG 1.73	Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants	1.7, 1.8
RG 1.75	Physical Independence of Electric Systems	1.8, 7.1.2.2.1, 7.1.2.2.2, 8.3.1, 8.3.2
RG 1.89	Qualification of Class 1E Equipment for Nuclear Power Plants	1.8, 8.3.1, 8.3.2
RG 1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	1.8, 6.2, 7.5, 9.3.2, 11.5, 12.3
RG 1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	1.8, 3.10, 8.3.1, 8.3.2
RG 1.105	Instrument Setpoints	1.8, 7.1.2.1.9, 7.5
RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves	1.8
RG 1.118	Periodic Testing of Electric Power and Protection Systems	1.8, 8.3
4. Branch Technical Positions (BTP)		
BTP ICSB 3	Isolation of Low Pressure Systems from the High Pressure Reactor Coolant System	7.6.2
BTP ICSB 4	Requirements of Motor-Operated Valves in the ECCS Accumulator Lines	7.6.4
BTP ICSB 5	Scram Breaker Test Requirements - Technical Specifications	7.2.2.2.3, Chapter 16

TABLE 7.1-1 (Cont)

Criteria	Title	Discussed In
BTP ICSB 9	Definition of Use of Channel Calibration - Technical Specification	Chapter 16
BTP ICSB 12	Protection System Trip Point Changes for Operation with Reactor Coolant Pumps Out of Service	7.2.2.2.1, 4.1.1, Chapter 16
BTP ICSB 13	Design Criteria for Auxiliary Feedwater Systems	7.3.2.3
BTP ICSB 14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	7.7.2.2, 15.4
BTP ICSB 18 (PSB)	Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves	Tech Spec. 3/4.5
BTP ICSB 20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	7.6.5, 7A, 6.3
BTP ICSB 21	Guidance for Application of Regulatory Guide 1.47	1.8, 7.1.2.5
BTP ICSB 22	Guidance for Application of Regulatory Guide 1.22	1, 8, 7.1.2.4
BTP ICSB 26	Requirements for Reactor Protection System Anticipatory Trips	7.2.1.1.2

NOTE:

*Effective dates based on purchase order dates.

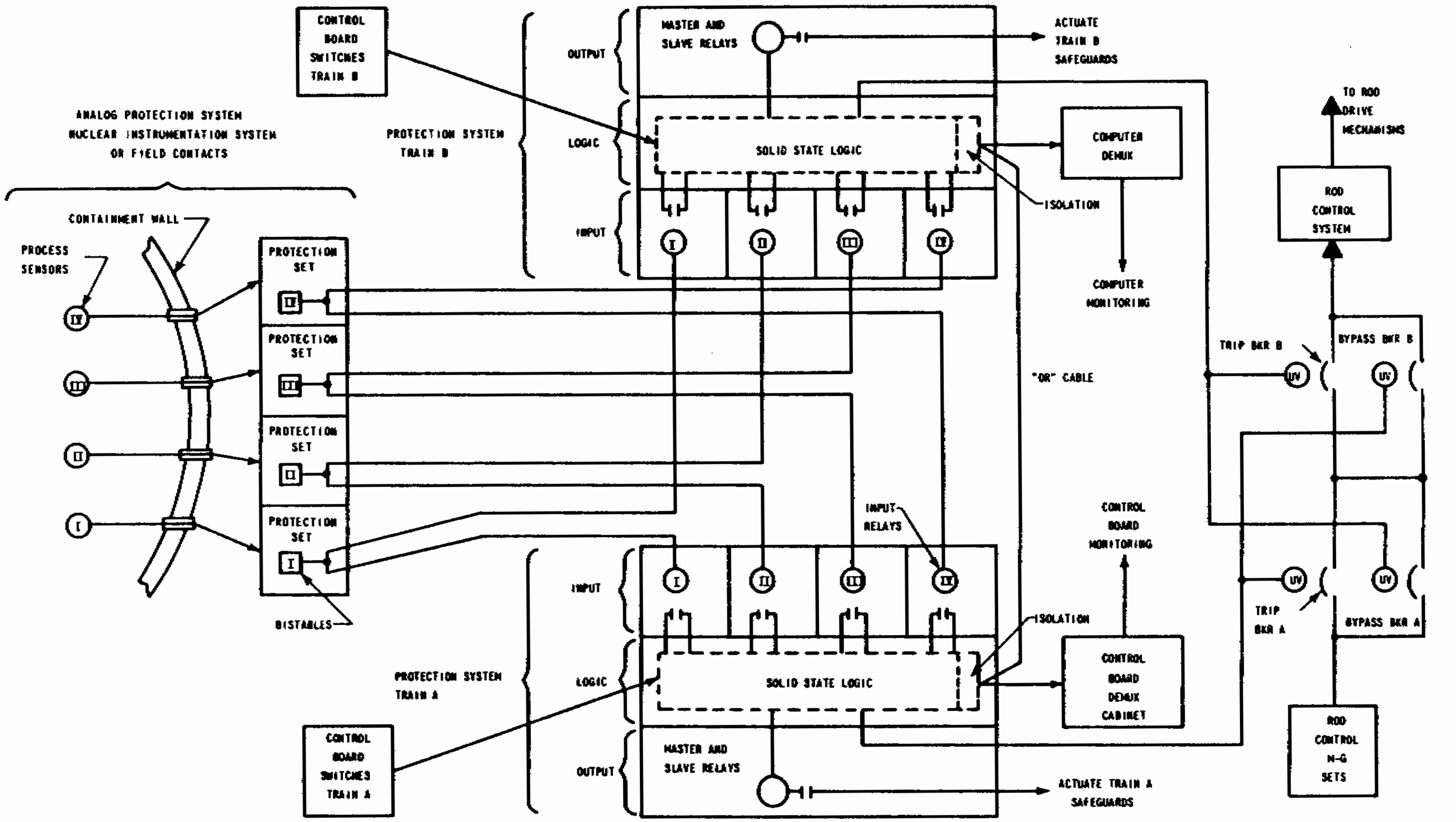

FIGURE 7.1-1
PROTECTION SYSTEM
BLOCK DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.2 REACTOR TRIP SYSTEM

7.2.1 Description

7.2.1.1 System Description

The reactor trip system (RTS) automatically prevents operation of the reactor in an unsafe region by shutting down the reactor whenever the limits of the safe region are approached. The safe operating region is defined by several considerations, such as mechanical/hydraulic limitations on equipment and heat transfer phenomena. Therefore, the RTS maintains surveillance on process variables which are directly related to equipment mechanical limitations such as pressure, pressurizer water level (to prevent water discharge through safety valves), and also on variables which directly affect the heat transfer capability of the reactor (that is, flow and reactor coolant temperatures). Still other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or calculated variable exceeds a set point, the reactor will be shut down in order to protect against either gross damage to fuel clad or loss of system integrity which could lead to release of radioactive fission products into the containment.

The following systems make up the RTS (Reid (1973); Lipchak (1974); and Katz (1971) provide additional background information on the systems):

1. Process instrumentation and control system,
2. Nuclear instrumentation system,
3. Solid state logic protection system,
4. Reactor trip switchgear, and
5. Manual actuation circuit.

The RTS consists of sensors which, when connected with analog circuitry consisting of two to four redundant channels, monitor various plant parameters, and digital circuitry, consisting of two redundant logic trains, which receives inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of the two trains, Trains A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively. The two trip breakers in series connect three-phase ac power from the rod drive motor-generator sets to the rod drive power cabinets, as shown on Figure 7.2-1, Sheet 2. During Beaver Valley Power Station - Unit 2 (BVPS-2) power operation, a dc undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of dc voltage to the undervoltage coil, as well as energization of the shunt trip coil, open the breaker. When either of the trip breakers opens, power is interrupted to the rod drive power supply and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers.

7.2.1.1.1 Functional Performance Requirements

The RTS automatically initiates reactor trip:

1. Whenever necessary to prevent fuel rod damage for an anticipated operational transient (American Nuclear Society (ANS) Condition II),

2. To limit core damage for infrequent faults (ANS Condition III), and

3. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary (RCPB) for limiting fault conditions (ANS Condition IV).

The RTS initiates a turbine trip signal whenever a reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive reactor system cooldown and thus avoids unnecessary actuation of the engineered safety features actuation system (ESFAS).

The RTS provides for manual initiation of reactor trip by operator action in the main control room.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the RTS reaches a preset level. To ensure a reliable system, high quality design, components, manufacturing, quality control, and testing are used. In addition to redundant channels and trains, the design approach provides a RTS which monitors numerous system variables, therefore providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2-1 provides a list of reactor trips, which are described as follows:

Nuclear Overpower Trips

The specific trip functions generated are as follows:

1. Power range high neutron flux trip

   The power range high neutron flux trip circuit trips the reactor when two out of four power range channels exceed the trip set point. There are two bistable amplifiers for overpower protection in each of four redundant nuclear instrumentation power range channels. Each has its own trip setting. The bistable trip setting (high setting), associated with monitoring the high end of the power range, provides overpower protection and is never blocked. The bistable trip setting (low setting), which provides a more restrictive protection limit during start-up and operation at low power level, can be manually blocked by the operator when two out of four power range channels indicate approximately 10 percent power (P-10). Three out of four channels below 10 percent automatically reinstates the trip (low setting) function. Table 7.2-2 provides a listing of all protection system interlocks and blocks.

2. Intermediate range high neutron flux trip

   The intermediate range high neutron flux trip circuit trips the reactor when one out of two intermediate range channels exceeds the trip set point. This trip, which provides protection during reactor start-up, can be manually blocked if two out of four power range channels are above approximately P-10. Three out of four power range channels below this value automatically reinstate the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during BVPS-2 shutdown or prior to start-up. This bypass action is annunciated on the main control board.

3. Source range high neutron flux trip

   The source range high neutron flux trip circuit trips the reactor when one of the two source range channels exceeds the trip set point. This trip, which provides protection during reactor start-up and BVPS-2 shutdown, can be manually bypassed when one out of two intermediate range channels reads above the P-6 set point value and is automatically reinstated when both intermediate range channels decrease below the P-6 set point value. This trip is also automatically bypassed by two out of four logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board-mounted switches. Each switch will reinstate the trip function in one of the two protection logic trains. The source range trip point is set between the P-6 set point (source range cutoff power) and the maximum source range power. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during BVPS-2 shutdown or prior to start-up. This bypass action is annunciated on the main control board.

4. Power range high positive neutron flux rate trip

   This circuit trips the reactor when an abnormal rate of increase in nuclear power occurs in two out of four power range channels. This trip provides departure from nucleate boiling

(DNB) protection against rod ejection accidents of low worth from mid-power and is always active.

Core Thermal Overpower Trips

The specific trip functions generated are as follows:

1. Overtemperature ΔT trip

   This trip protects the core against low DNBR and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. The set point for this trip is continuously calculated by analog circuitry for each loop by solving the equation found in Technical Specification Table 3.3.1-1.

A separate ion chamber unit supplies the flux signal for each overtemperature ΔT trip channel. Increases in Δϕ beyond a predefined deadband will result in a decrease in trip set point (Figures 7.2-2 and 7.2-3). The required one pressurizer pressure parameter per loop is obtained from separate sensors connected to three pressure taps at the top of the pressurizer. Section 7.2.2.3.3 provides an analysis of this arrangement. Figure 7.2-1, Sheet 5, shows the logic for overtemperature ΔT trip function.

2. Overpower ΔT trip

   This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. Table 7.2-4 describes other events for which the overpower ΔT trip may provide a backup or secondary trip function.

   The set point for each channel is continuously calculated, using the equation found in Technical Specification Table 3.3.1-1.

The source of temperature information is identical to that of the overtemperature ΔT trip, and the resultant ΔT set point is compared to the same ΔT. Figure 7.2-1, Sheet 5, shows the logic for this trip function.

Reactor Coolant System Pressurizer Pressure Trips

The specific trip functions generated are as follows:

1. Pressurizer low pressure trip

   The purpose of this trip is to protect against low pressure which could lead to DNB. The parameter being sensed is reactor coolant pressure, as measured in the pressurizer. Above P-7, the reactor is tripped when the pressurizer pressure measurements fall below preset limits. This signal is compensated to account for the fact that the measurement is in the pressurizer rather than in the core proper. This trip is blocked below P-7 to permit start-up. The trip logic and interlocks are given in Table 7.2-1, and the trip logic is shown on Figure 7.2-1, Sheet 6.

The reactor trips comply with the intent of NUREG-0737 (USNRC 1980), TMI Action Item II.K.1.17.

2. Pressurizer high pressure trip

   The purpose of this trip is to protect the reactor coolant system (RCS) against system overpressure and to prevent opening of the pressurizer safety valves. The same sensors and transmitters used for the pressurizer low pressure trip are used for the high pressure trip except that separate bistables are used for trip. These bistables trip when uncompensated pressurizer pressure signals exceed preset limits on coincidence, as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function. This trip protects against overstressing the RCPB. The logic for this trip is shown on Figure 7.2-1, Sheet 6.

3. Pressurizer high water level trip

   This trip is provided as a backup to the high pressurizer pressure trip and serves to prevent water relief through the pressurizer safety valves, and therefore provides for equipment protection. This trip is blocked below P-7 to permit start-up. The trip logic for this function is shown on Figure 7.2-1, Sheet 6.

<u>Reactor Coolant System Low Flow Trips</u>

These trips protect the core from DNB in the event of a loss-of-coolant flow (LOCF) situation. Figure 7.2-1, Sheet 5 shows the logic for these trips. The means of sensing the LOCF are as follows:

1. Low reactor coolant flow

   The parameter sensed is reactor coolant flow. Three differential pressure transmitters in each coolant loop are used to provide the status of reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. An output signal from two out of the three bistables in a loop would indicate a low flow in that loop. Above P-7, two out of three loop low flow indications will trip the reactor. Above P-8, low flow in any one loop will cause a reactor trip. The coincidence logic and interlocks are given in Table 7.2-1. Trip logic for this function is shown on Figure 7.2-1, Sheet 5.

2. Reactor coolant pump breaker trip

   One open breaker signal is generated for each reactor coolant pump (RCP). Above the P-7 set point, the reactor trips on two open breaker signals. One set of auxiliary contacts on each pump breaker serves as the input signal to the trip logic. The coincident logic and interlocks are given in Table 7.2-1. The trip logic for this function is shown on Figure 7.2-1, Sheet 5.

3. Reactor coolant pump bus undervoltage trip

   This trip is anticipatory to the low reactor coolant flow trip to protect against low flow which can result from loss of voltage to more than one RCP motor (for example, loss of offsite power or RCP breakers opening). There is one undervoltage sensing relay connected to each phase of each RCP bus. These relays provide an output signal when the bus voltage goes below approximately 70 percent of rated voltage. Signals from these relays are delayed to prevent spurious trips caused by short term voltage perturbations. The coincidence logic and interlocks are given in Table 7.2-1.

4. Reactor coolant pump bus underfrequency trip

   This trip is anticipatory to the low reactor coolant flow trip to protect against low flow resulting from pump underfrequency, for example, a major grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition. There is one underfrequency sensing relay connected to each RCP bus. Signals from relays connected to any two of the buses (time delayed up to approximately 0.5 second to prevent spurious trips caused by short term frequency perturbations) will trip the reactor if power is above P-7. 7.2-1, Sheet 5, shows the logic for the RCP underfrequency trip.

<u>Steam Generator Trips</u>

The specific trip functions generated are as follows:

1. Low-low steam generator water level trip

   This trip protects the reactor from loss of heat sink. This trip is actuated on two out of three low-low water level signals occurring in any steam generator. The logic is shown on Figure 7.2-1, Sheet 7.

<u>Reactor Trip On a Turbine Trip (Anticipatory)</u>

The reactor trip on a turbine trip is actuated by two out of three logic from low emergency trip fluid signals or by all closed signals from the turbine main stop valves. A turbine trip causes a direct reactor trip above P-9. The reactor trip on turbine trip provides additional protection and conservatism beyond that required. This trip is included as part of good engineering practice and prudent design. No credit is taken in any of the safety analyses (Chapter 15) for this trip.

The turbine provides anticipatory trips to the reactor protection system (RPS) from contacts which change state when the turbine main stop valves close or when the turbine emergency trip fluid pressure goes below its set point.

The anticipatory trips comply with the intent of NUREG-0737 (USNRC 1980), TMI Action Items II.K.3.10 and II.K.3.12.

One of the design bases considered in the protection system is the possibility of an earthquake. With respect to these contacts, their functioning is unrelated to a seismic event in that they are anticipatory to other diverse parameters which cause reactor trip. The contacts are shut during BVPS-2 operation and open to cause reactor trip when the turbine is tripped. No power is provided to the protection system from the contacts; they merely serve to interrupt power to cause reactor trip. This design functions in a de-energize-to-trip fashion to cause a plant trip if power is interrupted in the trip circuitry. This ensures that the protection system will in no way be degraded by this anticipatory trip because seismic design considerations do not form part of the design bases for anticipatory trip sensors. (The RPS cabinets which receive the inputs from the anticipatory trip sensors are seismically qualified, as discussed in Section 3.10.)

Circuit analysis show that the functional performance of the protection system would not be degraded by credible electrical faults, such as opens and shorts in the circuits associated with reactor trip from turbine trip. The contacts of redundant sensors on the steam stop valves and the trip fluid pressure system are connected through the grounded side of the ac supply circuits in the solid state protection system (SSPS). Loss of signal caused by circuit faults would produce either a partial or full reactor trip.

The sensing devices associated with, or mounted on the turbine conform to requirements applicable to the anticipatory trip of the reactor. The anticipatory trips thus meet Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971 and Branch Technical Position ICSB 26, including redundancy, separation, single failure, etc. Seismic qualification of the contacts sensors is not required. The logic for this type of trip is shown on Figure 7.2-1, Sheet 15.

Safety Injection Signal Actuation Trip

A reactor trip occurs when safety injection is actuated. The means of actuating safety injection is described in Section 7.3. Figure 7.2-1, Sheet 8, shows the logic for this trip.

Manual Trip

The manual trip consists of two switches with two outputs on each switch. One output is used to actuate the Train A trip breaker, the other output actuates the Train B trip breaker. Operating a manual trip switch removes the voltage from the undervoltage coil and energizes the shut trip coils in the breakers. There are no interlocks which can block this trip. Figure 7.2-1, Sheet 3, shows the manual trip logic.

7.2.1.1.3 Reactor Trip System Interlocks

Power Escalation Permissives

The overpower protection provided by the out-of-core nuclear instrumentation consists of three discrete, but overlapping, ranges. Continuation of start-up operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range trips can be manually blocked by the operator.

One of two intermediate range permissive signals (P-6) is required prior to source range trip blocking. A source range manual block is provided for each logic train and the blocks must be in effect on both trains in order to continue power escalation. Source range trips are automatically reactivated when both intermediate range channels are below the permissive (P-6) set point. There are two manual reset switches for administratively reactivating the source range trip and detector high voltage when between permissives P-6 and P-10, if required. Source range trip block and high voltage cutoff are always maintained when power is above the permissive P-10 set point with high voltage manual control switch in the normal position. If the high voltage manual control switch, located on the source range drawer, is in the on or off position, it overrides any automatic actions.

The intermediate range trip and power range (low set point) trip can only be blocked after satisfactory operation and permissive information are obtained from two of four power range channels. Individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (one switch for each train for a total of four switches). These trips are automatically reactivated when any three out of the four power range channels are below the permissive (P-10) set point, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown on Figure 7.2-1, Sheet 4. All of the permissives are digital, and they are derived from analog signals in the nuclear power range and intermediate range channels. Table 7.2-2 provides the list of protection system interlocks.

Block of Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip (below approximately 10 percent of full power) on a low reactor coolant flow in more than one loop, two or more RCP breakers open, RCP undervoltage, RCP underfrequency, pressurizer low pressure, or pressurizer high water level. Figure 7.2-1, Sheets 5 and 6, illustrate permissive applications. The low power signal (P-7) is derived from three out of four power range neutron flux signals below the set point in coincidence with two out of two turbine first stage pressure signals below the set point (low plant load). The permissive logic is shown on 7.2-1, Sheet 4.

The P-8 interlock blocks a reactor trip when the plant is below approximately 30 percent of full power, on a low reactor coolant flow in any one loop. The block action (absence of the P-8 interlock signal) occurs when three out of four neutron flux power range signals are below the set point. Thus, below the P-8 set point, an automatic reactor trip will not occur until two loops are indicating low flow. Figure 7.2-1, Sheet 4, shows derivation of P-8, and Sheet 5, for its function in the low flow reactor trip logic.

The P-9 interlock blocks reactor trip on a turbine trip when the plant is below approximately 49 percent of full power. The block action (absence of the P-9 interlock signal) occurs when three out of four neutron flux power range signals are below the set point. Thus, below the P-9 set point, the reactor will be allowed to operate if the turbine has tripped. Figure 7.2-1, Sheet 4, depicts derivation of P-9, and Sheet 15 shows applicable logic. The list of protection system blocks is given in Table 7.2-2.

7.2.1.1.4 Coolant Temperature Sensor Arrangement

The hot and cold leg temperature signals required for input to the protection and control functions are obtained using thermowell mounted RTDs installed in each reactor coolant loop.

The hot leg temperature measurement in each loop is accomplished using three fast response narrow range RTDs mounted in thermowells. Two of the three thermowells in each loop are located within the scoops previously used to supply temperature samples to the RTD bypass manifold. The third RTD could not be located within the scoop due to structural interferences and is located upstream from the scoop plane. The two scoops used to accommodate the thermowells were modified by machining a flow hole in the end of the scoop to facilitate the flow of water through the existing holes in the leading edge of the scoop and passed the temperature sensitive tip of the RTD.

Due to temperature streaming the temperatures measured by the three hot leg RTDs are different and therefore these signals are electronically averaged to generate a hot leg average temperature. Provisions were made in the RTD electronics to allow for operation with only two RTDs in service. The two RTD measurement can be biased to correct for the difference compared with the three RTD average.

The cold leg temperature measurement in each loop is accomplished by one fast response, narrow range, dual element RTD. The original cold leg RTD bypass penetration nozzle was modified to accept the thermowell.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature at the cold leg, T_{cold},) and an average reactor coolant temperature (T_{avg}). The T_{avg} for each loop is indicated on the main control board.

Wide Range Cold Leg and Hot Leg Temperatures

Wide Range temperature detectors, located in the thermometer wells in the cold and hot leg piping of each loop, supply signals to wide range temperature recorders. This information is used by the operator to control coolant temperature during start-up and shutdown.

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation includes a tank level arrangement using differential pressure between an upper and lower tap.

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems: the process instrumentation system and the nuclear instrumentation system (NIS).

Process instrumentation includes those devices (and their interconnection into systems) which measure temperature, pressure, fluid flow, and fluid level as in tanks or vessels. Process instrumentation specifically excludes nuclear and radiation measurements. The process instrumentation includes the process measuring devices, power supplies, indicators, recorders, alarm actuating devices, controllers, signal conditioning devices, etc, which are necessary for day-to-day operation of the nuclear steam supply system as well as for monitoring BVPS-2, and providing initiation of protective functions upon approach to unsafe plant conditions.

The primary function of nuclear instrumentation is to protect the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during start-up and power operation. The NIS uses information from these separate types of instrumentation channels to provide three discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection, beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary.

The lowest range (source range) covers six decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than two counts per second. The next range (intermediate range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation (power range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

The system previously described provides main control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, start-up, and power operation, as well as during subsequent refueling. Start-up rate indication for the source and intermediate range channels is provided at the main control board. Reactor trip, rod stop, control and alarm signals are transmitted to the reactor control and protection system for automatic plant control. Equipment failures and test status information are annunciated in the main control room.

Reid (1973) and Lipchak (1974) provide additional background information on the process and nuclear instrumentation.

7.2.1.1.7 Solid State Protection System

The SSPS takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of BVPS-2 parameters. The system combines these signals in the required logic combination and generates a trip signal simultaneously to the shunt trip coils and to the undervoltage trip attachment and shunt trip auxiliary relay coils of the reactor trip circuit breakers when the necessary combination of signals occur. The system also provides annunciator, status light, and computer input signals which indicate the condition of bistable input signals, partial trip, and full trip functions and the status of the various blocking, permissive, and actuation functions. In addition the system includes means for semi-automatic testing of the logic circuits.

7.2.1.1.8 Isolation Amplifiers

In certain applications, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE Standard 279-1971.

In all of these cases, except as stated below, analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring. Steam flow and feedwater flow no longer have protective functions since the low feedwater trip was eliminated, but portions of these loops are still protection grade due to their association with the protection racks and color coded signal cable routing. Additional informationand discussions can be found in Section 7.1.2.2.1.

7.2.1.1.9 Energy Supply and Environmental Variations

The energy supply for the RTS, including the voltage and frequency variations, is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform, are given in Section 3.11 and Chapter 8.

7.2.1.1.10 Set Points

The set points that require trip action are given in Chapter 16. Further discussion on set points is found in Section 7.1.2.1.9.

7.2.1.1.11 Seismic Design

The seismic design considerations for the RTS are given in Section 3.10. This design meets the requirements of General Design Criterion (GDC) 2.

7.2.1.2 Design Bases Information

The following information presents the design bases information requested by Section 3 of IEEE Standard 279-1971. Functional logic diagrams are presented on Figure 7.2-1.

7.2.1.2.1 Generating Station Conditions

The following are the generating station conditions requiring reactor trip.

1. The DNBR approaching 1.30,

2. Power density (kW/ft) approaching rated value for Condition II faults (Chapter 4 discusses fuel design limits), or

3. The RCS overpressure creating stresses approaching the limits specified in Chapter 5.

7.2.1.2.2 Generating Station Variables

The following are the variables required to be automatically monitored in order to provide reactor trips (Table 7.2-1).

1. Neutron flux,

2. Reactor coolant temperature,

3. Reactor coolant system pressure (pressurizer pressure),

4. Pressurizer water level,

5. Reactor coolant flow,

6. Reactor coolant pump operational status (bus voltage and frequency, and breaker position),

7. Steam generator water level, and

8. Turbine-generator operational status (trip fluid pressure and stop valve position).

7.2.1.2.3 Spatially Dependent Variables

The following variable is spatially dependent:

Reactor coolant temperature: Section 7.3.1.2 discusses this variable's spatial dependence.

7.2.1.2.4 Limits and Margins

The parameter values that will require reactor trip are given in Chapter 16, Technical Specifications, and in Chapter 15, Accident Analyses. Chapter 15 demonstrates that the set points used in Chapter 16 are conservative.

The set points for the various functions in the RTS have been analytically determined such that the operational limits so prescribed will prevent fuel rod clad damage and loss of integrity of the RCS as a result of any Condition II incident (anticipated malfunction). As such, during any Condition II incident, the RTS limits the following parameters to:

1. Minimum DNBR = 1.3,

2. Maximum system pressure = 2,750 psia, and

3. Fuel rod maximum linear power = 15.2 kW/ft.

The accident analyses described in Chapter 15 demonstrate that the functional requirements as specified for the RTS are adequate to meet the preceding considerations, even assuming, for conservatism, adverse combinations of instrument errors. A discussion of the safety limits associated with the reactor core and RCS, plus the limiting safety system set points, are presented in the Technical Specifications.

7.2.1.2.5 Abnormal Events

The following malfunctions, accidents, or other unusual events which could physically damage RTS components or could cause environmental changes are considered in design:

1. Earthquakes (Chapters 2 and 3),

2. Fire (Section 9.5),

3. Explosion (hydrogen buildup inside containment, Section 6.2.5),

4. Missiles (Section 3.5),

5. Flood (Chapters 2 and 3), and

6. Wind and tornadoes (Section 3.3).

The RTS fulfills the requirements of IEEE Standard 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions. The RTS includes provisions to provide protection against destruction of the system from fires, explosions, flood, wind, and tornadoes (refer to items 1 through 6). The discussions in Section 7.1.2.1.7 and this section adequately address or reference the coverage of the effects of abnormal events on the RTS in conformance with the applicable GDC.

7.2.1.2.6 Minimum Performance Requirements

Reactor Trip System Response Times

The RTS response time is defined in Section 7.1. Allowable response times are contained in Licensing Requirements Manual Table 3.3.1-1. Section 7.1.2.7 provides a discussion of periodic response time verification capabilities.

Reactor Trip Accuracies

Accuracy is defined in Section 7.1. Reactor trip accuracies are tabulated in Table 7.2-3. The trip set point is determined by factors other than the most accurate portion of the instrument's range. The safety limit set point is determined only by the accident analysis. As described previously, allowance is then made for process uncertainties, instrument error, instrument drift, and calibration uncertainty to obtain the nominal set point value, which is actually set into the equipment. The only requirement on the instrument's accuracy value is that over the instrument span, the error must always be less than or equal to the error value allowed in the accident analysis. The instrument does not need to be the most accurate at the set point value as long as it meets the minimum accuracy requirement. The accident analysis accounts for the expected errors at the actual set point.

Protection System Ranges

Typical protection system ranges are tabulated in Table 7.2-3. Range selection for the instrumentation covers the expected range of the process variable being monitored during power operation. Limiting set points are at least 5 percent from the end of the instrument span.

7.2.2 Analyses

7.2.2.1 Failure Modes and Effects Analyses

A failure modes and effects analysis of the RTS has been performed. Results of this fault tree analysis are presented by Gangloff (1971).

7.2.2.2 Evaluation of Design Limits

While most set points used in the RTS are fixed, there are variable set points, most notably the overtemperature ΔT and overpower ΔT set points. All set points in the RTS have been selected on the basis of engineering design or safety studies. The capability of the RTS to prevent loss of integrity of the fuel clad and/or RCS pressure boundary during Condition II and III transients is demonstrated in Chapter 15. These accident analyses are carried out using those set points determined from results of the engineering design studies. Set point limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips of the accident analyses (where appropriate) which utilizes this trip is presented as follows. It should be noted that the selected trip set points all provide for margin before protection action is actually required to allow for uncertainties and instrument errors. The design meets the requirements of GDC 10 and 20.

7.2.2.2.1 Trip Set Point Discussion

It has been pointed out previously that below a DNBR of 1.30 there is likely to be significant local fuel clad failure. The DNBR existing at any point in the core for a given core design can be determined as a function of the core inlet temperature, power output, operating pressure, and flow. Consequently, core safety limits in terms of a DNBR equal to 1.30 for the hot channel can be developed as a function of ΔT, T_{avg}, and pressure for a specified flow, as illustrated by the solid lines on Figure 7.2-3. Also shown as solid lines on Figure 7.2-3 are the locus of conditions equivalent to 118 percent of power as a function of ΔT and T_{avg} representing the overpower (kW/ft) limit on the fuel. The dashed lines indicate the maximum permissible set point (ΔT) as a function of T_{avg} and pressure for the overtemperature and overpower reactor trip. Actual values of set point constants in the equation representing the dashed lines are as given in the Technical Specifications. These values are conservative to allow for instrument errors. The design meets the requirements of GDC 10, 15, 20, and 29.

The DNBR is not a directly measurable quantity; however, the process variables that determine DNBR are sensed and evaluated. Small isolated changes in various process variables may not individually result in violation of a core safety limit; whereas the combined variations, over sufficient time, may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the RTS accommodates this situation by providing reactor trips associated with individual process variables in addition to the overpower/overtemperature safety limit trips. Process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should operation continue. Basically, the high pressure, low pressure, and overpressure/overtemperature ΔT trips provide sufficient protection for slow transients, as opposed to such trips as low flow or high flux which will trip the reactor rapidly for changes in flow or flux, respectively, that would result in fuel damage before actuation of the slower responding ΔT trips could be effected.

Therefore, the RTS has been designed to provide protection for fuel cladding and RCS pressure boundary integrity where: 1) a rapid change in a single variable of factor which will result in exceeding a core or a system safety limit, and 2) a slow change in one or more variables will have an integrated effect which will cause safety limits to be exceeded. Overall, the RTS offers diverse and comprehensive protection against fuel clad failure and/or loss of RCS integrity for Condition II and III accidents. Table 7.2-4 lists the various trips of the RTS.

The RTS design was evaluated in detail with respect to common mode failure and is presented by Reid (1973). The design meets the requirements of GDC 21.

Preoperational testing is performed on RTS components and systems to determine equipment readiness for start-up. This testing serves as a further evaluation of the system design.

Analyses of the results of Condition I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences, are presented in Chapter 15. The instrumentation installed to mitigate the consequences of load rejection and turbine trip is addressed in Section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the RCS are instrument devices that indicate the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equation:

$$\frac{\Delta P}{\Delta P_o} = \left(\frac{w}{w_o}\right)^2 \qquad (7.2\text{-}3)$$

where ΔP_o is the pressure differential at the reference flow W_o, and ΔP is the pressure differential at the corresponding flow, w. The full flow reference point is established during initial BVPS-2 start-up. The low flow trip point is then established by extrapolating along the correlation curve. The expected absolute accuracy of the channel is within ±10 percent of full flow and field results have shown the repeatability of the trip point to be within ±1 percent.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

The RTS meets the GDC and IEEE Standard 279-1971 as follows:

General Functional Requirement

The protection system automatically initiates appropriate protective action whenever a condition monitored by the system reaches a preset value. Functional performance requirements are given in Section 7.2.1.1.1; Section 7.2.1.2.4 presents a discussion of limits and margins; Section 7.2.1.2.5 discusses unusual (abnormal) events; and Section 7.2.1.2.6 presents minimum performance requirements.

Single Failure Criterion

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and two logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent system protective action at the system level when required.

Single failure within the protection system shall not prevent proper protective action at the system level when required. Components and systems not qualified for seismic events or accident environments and nonsafety-grade components and systems are assumed to fail to function if failure adversely affects protection system performance. These components and systems are assumed to function if functioning adversely affects protection system performance. All failures in the protection system that can be predicted as a result of an event for which the protection system is designed to provide a protective function are assumed to occur if the failure adversely affects the protection system performance. After assuming the failures of nonsafety-grade, non-qualified equipment and those failures caused by a specific event, a random single failure is arbitrarily assumed. With these failures assumed, the protection system must be capable of performing the protective functions credited in the accident analyses.

Loss of input power, the most likely mode of failure, to a channel or logic train will result (except for containment spray) in a signal calling for protective action. This design meets the requirements of GDC 23.

To prevent the occurrence of common mode failures, functional diversity, physical and electrical separation, and testing are employed, as discussed by Gangloff (1971). The design meets the requirements of GDC 21 and 22.

Quality of Components and Modules

The quality assurance requirements imposed on the components and modules used in the RTS satisfy GDC 1.

Equipment Qualification

Sections 3.10 and 3.11 discuss the type tests made to verify the performance requirements. The test results demonstrate that the design meets the requirements of GDC 4.

Channel Integrity

Protection system channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, energy supply, malfunctions, and accidents. Vital power for the RTS is described in Section 7.6 and Chapter 8. The environmental variations throughout which the system will perform is discussed in Section 3.11.

Independence

Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate ac power feed. This design meets the requirements of GDC 21.

Two reactor trip breakers are actuated by two separate logic matrices which interrupt power to the control rod drive mechanisms (CRDMs). The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all CRDMs, permitting the rods to fall into the core (Figure 7.1-1).

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. The extent of this diversity has been evaluated for a wide variety of postulated accidents. Generally, two or more diverse protection functions would terminate an accident before intolerable consequences could occur. This design meets the requirements of GDC 22.

Control and Protection System Interaction

The protection system is designed to be independent of the control system. In certain applications the control signals and other nonprotective functions are derived from individual protective channels through isolation amplifiers. The isolation amplifiers are classified as part of the protection system and are located in the protection racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed such that a short circuit, open circuit, or the application of credible fault potentials on the isolated output portion of the circuit (that is, the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protection racks. In addition to employing isolation between protection and control circuits, control circuit design also prevents adverse protection/control circuit interaction. An example of such a design is the use of the median signal selector in the steam generator water level control circuit. The median signal selector receives the three level measurement signals and transmits the median of these signals for level control purposes. This signal will reject a failed high or low steam generator level measurement and therefore this failure will not affect the system. The control and protection system interaction has been eliminated by the median signal selector design. This design meets the requirements of GDC 24 and Paragraph 4.7 of IEEE Standard 279-1971.

The results of applying fault conditions on the output portion of the isolation amplifiers show that no significant disturbance to the isolation amplifier input signal occurred. Section 7.1.2.2.1 provides a discussion of additional tests on the protection system.

Derivation of System Inputs

To the extent feasible and practical, protection system inputs are derived from signals which are direct measures of the desired variables. Variables monitored for the various reactor trips are listed in Section 7.2.1.2.2.

Capability for Sensor Checks

The operational availability of each system input sensor during reactor operation is accomplished by cross-checking between channels that bear a known relationship to each other and that have readouts available. Channel checks are discussed in Chapter 16.

Capability for Testing

The RTS is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to assure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22, as discussed in Section 7.1.2.4.

The protection system is designed to permit periodic testing of the analog channel portion of the RTS during reactor power operation without initiating a protective action. This is because of the coincidence logic required for reactor trip. These tests may be performed at any plant power from cold shutdown to full power. Before starting any of these tests with BVPS-2 at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode and the plant in stable operation in order to avoid spurious trips. Set points are located in the technical specifications.

1. Analog Channel Tests

   Analog channel testing is performed at the analog instrumentation cabinet by individually inputting signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Proving lamps and analog test switches are provided in the analog racks. The bistable output is put in a trip condition by placing the test switch in the test position. This action connects the proving lamp to the bistable and disconnects and thus de-energizes (operates) the associated input relays in Train A and Train B logic cabinets. This permits injection of a test signal to the channel. Relay logic in the process cabinets automatically blocks the test signal unless the bistable amplifier is tripped. This is done on one channel at a time. Interruption of the bistable output to the logic circuitry for any cause (test, maintenance purposes, or removed from service) will cause that portion of the logic to be actuated (partial trip) accompanied by a partial trip alarm and channel status light actuation in the main control room. A simulated signal is then injected at a test jack. Verification of the bistable trip setting is now confirmed by the proving lamp. Each channel contains those switches, test points, etc., necessary to test the channel. It is estimated that analog testing can be performed at a rate of several channels per hour. Reid (1973) provides additional information.

The following periodic tests of the analog channels of the protection system are performed:

a. T_{avg} and ΔT protection channel testing,

b. Pressurizer pressure protection channel testing,

c. Pressurizer water level protection channel testing,

d. Steam generator water level protection channel testing,

e. Reactor coolant low flow, underfrequency, and undervoltage protection channel testing,

f. Turbine first stage pressure channel testing,

g. Steam pressure protection channel testing, and

h. Containment pressure testing.

2. Nuclear Instrumentation Channel Tests

The power range channels of the NIS are tested by either superimposing a test signal on the actual detector signal being received by the channel at the time of testing or by injecting a test signal in place of the actual detector signal. The output of the bistable is not placed in a tripped condition prior to testing when testing is performed by superimposing a signal. Also, since the power range channel logic is two out of four, bypass of this reactor trip function is not required.

To test a power range channel, a test-operate switch is provided to require deliberate operator action, and operation of which will initiate the channel test annunciator in the main control room. Bistable operation is tested by increasing the test signal to bistable trip set point and verifying bistable relay operation by main control board annunciator and trip status lights. The positive rate trip bistables are tested using the same procedure. Detailed step-by-step test procedures are described in the Nuclear Instrumentation Technical Manual.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the NIS detector.

An NIS channel which can cause a reactor trip through one of two protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. These bypasses are annunciated in the main control room.

The following periodic tests of the NIS are performed:

a. Testing at BVPS-2 shutdown:

   1) Source range testing,

   2) Intermediate range testing, and

   3) Power range testing.

b. Testing between P-6 and P-10 permissive power levels:

   1) Source range testing,

   2) Intermediate range testing, and

   3) Power range testing.

c. Testing above P-10 permissive power level.

   1) Source range testing, and

   2) Power range testing.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and trouble shooting procedures provided in the BVPS-2 technical manual for the NIS. Protection trip set points are indicated in the BVPS-2 technical specifications. Additional background information on the NIS, is discussed by Lipchak (1974).

3. Solid State Logic Testing

The reactor logic trains of the RTS are designed to be capable of complete testing at power. After the individual channel analog testing is complete, the logic matrices are tested from the Train A and Train B logic rack test panels. This step provides overlap between the analog and logic portions of the test program. During this test, each of the logic inputs are actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained sufficiently long enough to permit master relay actuation (master relays are pulsed in order to check continuity). Following the logic testing, the individual master relays are actuated electrically to test their mechanical operation. Actuation of the master relays during this test will apply low voltage to the slave relay coil circuits to allow continuity checking but not slave relay actuation. During logic testing of one train, the other train can initiate any required protective functions. Annunciation is provided in the main control room to indicate when a train is in test (train output bypassed) and when a reactor trip breaker is bypassed. Logic testing can be performed in less than 30 minutes. Additional background information on the logic system testing is given by Katz (1971).

A direct reactor trip resulting from undervoltage or underfrequency on the RCP buses is provided as discussed in Section 7.2.1 and shown on Figure 7.2-1. The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, the sequence is such that an overlap is provided between parts so that a complete logic test is provided. Opening of the RCP breakers during power operation is not possible since a reactor trip would occur as a result of low reactor coolant flow.

This design complies with the testing requirements of the applicable criteria as addressed in Section 7.1.2.4. Details of the method of testing and compliance with these standards are provided in Section 7.2.2.2.3.

The permissive and block interlocks associated with the RTS and ESFAS are given in Tables 7.2-2 and 7.3-3 and designated protection or P interlocks. As a part of the protection system, these interlocks are designed to meet the testing requirements of IEEE Standards 279-1971 and 338-1977.

Testing of all protective system interlocks is provided by the logic testing and semi-automatic testing capabilities of the SSPS. In the SSPS, the undervoltage trip attachment and shunt trip auxiliary relay coils (reactor trip) and master relays (engineered safeguards actuation) are pulsed for all combinations of trip or actuation logic with and without the interlock signals. For example, reactor trip on low flow is tested to verify operability of the trip above P-7 and nontrip below P-7 (Figure 7.2-1, Sheet 5). Interlock testing may be performed at power.

Testing of the logic trains of the RTS includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

a. Check of input relays

   During testing of the process instrumentation system and NIS channels, each channel bistable is placed in a trip mode causing one input relay in Train A and one in Train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Each reactor trip input relay contact causes a status lamp and an annunciator on the control board to operate. Either the Train A or Train B input relay operation will light the status lamp and annunciator.

Each train contains a multiplexing test switch. At the start of a process or NIS test, this switch (in either train) is placed in the A + B position. The A + B position alternately allows information to be transmitted from the two trains to the main control board. A steady status lamp and annunciator indicates that input relays in both trains have been de-energized. A flashing lamp means that the input relays in the two trains did not both de-energize. Contact inputs to the logic protection system such as RCP bus underfrequency relays operate input relays which are tested by operating the remote contacts as described previously and using the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the main control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two out of four channels trip becomes a one out of three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

b. Check of logic matrices

Logic matrices are checked one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semi-automatic test panel in the train. At the completion of the logic matrix tests, closure of the input error inhibit switch contacts is verified by either a continuity check or by channel inputs that are tripped.

The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus, there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage trip attachment and shunt trip auxiliary relay coils to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil does not de-energize.

Test indications that are provided are: an annunciator in the main control room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semi-automatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

4. General Warning Alarm Reactor Trip

Each of the two trains of the SSPS is continuously monitored by the general warning alarm RTS. The warning circuits are actuated if undesirable train conditions are set up by improper alignment of testing systems, circuit malfunction, or failure, etc as listed subsequently. A trouble condition in a logic train is indicated in the main control room. However, if any one of the conditions exists in Train A at the same time any one of the conditions exists in Train B, the reactor will be automatically tripped by the general warning alarm system. These conditions are:

a. Loss of either of two 48 V dc or either of two 15 V dc power supplies,

b. Printed circuit card improperly inserted,

c. Input error inhibit switch in the inhibit position,

d. Slave relay tester mode selector in test position,

e. Multiplexing selector switch in inhibit position,

f. Train bypass breaker racked in and closed,

g. Permissive or memory test switch not in off position,

h. Logic function test switch not in off position, or

i. Loss of power to the output cabinet.

5. Testing of Reactor Trip Breakers

Normally, reactor trip breakers 52/RTA and 52/RTB are in service and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers. The following procedure describes the method used for testing the trip breakers:

a. With bypass breaker 52/BYA racked out, manually close and trip it to verify its operation.

b. Rack in and close 52/BYA. Manually trip 52/RTA through a protection system logic matrix while at the same time operating the "Auto Shunt Trip Block" pushbutton on the automatic shunt trip panel. This verifies operation of the undervoltage trip attachment (UVTA) when the breaker trips. After reclosing RTA, trip it again by operation of the "Auto Shunt Trip Test" pushbutton on the automatic shunt

Trip panel. This is to verify tripping of the breaker through the shunt trip device.

c. Reset 52/RTA.

d. Trip and rack out 52/BYA.

e. Repeat preceding steps to test trip breaker 52/RTB using bypass breaker 52/BYB.

Auxiliary contacts of the bypass breakers are connected in the alarm system of their respective trains such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breakers and both bypass breakers will automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to close the bypass breaker in one train while the bypass breaker of the other train is already closed, both bypass breakers will automatically trip.

The Train A and Train B alarm systems operate separate annunciators in the main control room. The two bypass breakers also operate an annunciator in the main control room. Bypassing of a protection train with either the bypass breaker or with the test switches will result in both audible and visual indications.

The complete RTS is normally required to be in service. However, to permit online testing of the various protection channels or to permit continued operation in the event of a system instrumentation channel failure, a Technical Specification defining the minimum number of operable channels and the minimum degree of channel redundancy, has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability and degree of redundancy requirements cannot be met.

<u>Channel Bypass or Removal From Operation</u>

The protection system is designed to permit periodic testing of the analog channel portion of the RTS during reactor power operation without initiating a protective action, unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip.

<u>Operating Bypasses</u>

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the protective system and are designed in accordance with the criteria of this section. Indication is provided in the main control room if some part of the system has been administratively bypassed or taken out of service.

Indication of Bypasses

Bypass indication is discussed in Section 7.1.2.5.

Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions. Additional background information is provided by Reid (1973).

Multiple Set Points

For monitoring neutron flux, multiple set points are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to assure that the more restrictive trip set point is used. The devices used to prevent improper use of less restrictive trip settings are considered part of the protective system and are designed in accordance with the criteria of this section.

Completion of Protective Action

The protection system is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

Manual Initiation

Switches are provided on the main control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment. This meets the intent of Regulatory Guide 1.62.

Access

The design provides for administrative control of access to all set point adjustments, module calibration adjustments, and test points. Additional background information, is provided by Reid (1973).

Identification of Protective Actions

Protective channel identification is discussed in Section 7.1.2.3. Indication is discussed subsequently.

Information Readout

The protection system provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature) which can cause a reactor trip will be either indicated or recorded for every channel, including all neutron flux power range currents (top detector, bottom detector, algebraic difference, and average of bottom and top detector currents).

Any reactor trip will actuate an alarm and an indicator in the main control room. Such protective actions are indicated and identified down to the channel level.

Alarms and indicators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

System Repair

The system is designed to facilitate the recognition, location, replacement, and repair of malfunctioning components or modules. The capability for testing was previously discussed in Section 7.2.2.2.3.

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

Four power range neutron flux channels are provided for overpower protection. An isolation signal is also provided for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but a two out of four overpower trip logic ensures an overpower trip, if needed, even with an independent failure in another channel.

In addition, channel deviation signals in the control system will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the control system will respond only to rapid changes in indicated neutron flux. Slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range channel will block manual rod withdrawal. The set point for this rod stop is below the reactor trip set point. The automatic rod withdrawal function has been removed from the plant.

7.2.2.3.2 Coolant Temperature

The accuracy of the RTD loop temperature measurements is demonstrated during BVPS-2 start-up tests by comparing the temperature measurements from all RTDs with one another, as well as with the temperature measurements obtained from the wide range RTD located in the hot leg and cold leg piping of each loop. The comparisons are done with the RCS in an isothermal condition. The RTS setpoints are based on percentages of the indicated ΔT at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which are inherent. Therefore, the percent ΔT scheme is relative, not absolute, and provides better protective action without the expense of accuracy. For this reason, the linearity of the ΔT signals, as a function of power, is of importance rather than the absolute values of the ΔT. As part of the BVPS-2 start-up tests, the loop RTD signals will be compared with the core exit thermocouple signals during isothermal RCS conditions.

Plant control is based upon signals derived from protection system channels after isolation, by isolation amplifiers such that no feedback effect can perturb the protection channels.

The input signals (one per loop) to the Reactor Control System are obtained from electronically isolated protection Tavg and Delta-T signals. A Median Signal Selector (MSS) is implemented in the Reactor Control System, one for Tavg and one for Delta-T. The MSS receives three signals as input and selects the median signal for input to the appropriate control systems. Any single failure, high or low, in a calculated temperature will not result in an adverse control system response since the failed high or low temperature signal will be rejected by the MSS.

Hence, the implementation of a MSS in the Reactor Control System in conjunction with two out of three protection logic satisfies the requirements of IEEE 279-1971, Section 4.7, "Control and Protection System Interaction".

The response time allocated for measuring RCS hot and cold leg temperatures using thermowell mounted fast response RTDs is four seconds. This response time does not include the process electronics.

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the median value. The manual rod withdrawal blocks and turbine runback (power demand reduction) will also occur if any two out of the three overtemperature or overpower ΔT channels indicate an adverse condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature T trip protection function. Separate control channels are used to control pressurizer spray and heaters and pressurizer power-operated relief valves (PORVs). Pressurizer pressure is sensed by fast response pressure transmitters.

A spurious high pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip and in the logic for safety injection to ensure low pressure protection.

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a set point of 2,500 psia and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the pressurizer PORVs during this surge.

In addition, operation of any one of the pressurizer PORVs can maintain pressure below the high pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

7.2.2.3.4 Pressurizer Water Level

Three pressurizer water level channels are used for reactor trip. Isolated signals from these channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of 1/2 hour or more).

The high water level trip set point provides sufficient margin such that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve set point.

For control failures which tend to empty the pressurizer, two out of three logic for safety injection action on low pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time is available and alarms exist to alert the operator of the need for appropriate action.

7.2.2.3.5 Steam Generator Water Level

The basic function of the reactor protection circuit associated with low steam generator water level is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition, auxiliary feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip. This reactor trip acts before the steam generators are dry to reduce the required capacity and increase the starting time requirements of these auxiliary feedwater pumps, and to minimize the thermal transient on the RCS and steam generators. A low-low steam generator water level reactor trip circuit is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient.

It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents. Hence, it should be noted that controller malfunctions caused by a protection system failure will affect only one steam generator. Additionally, the steam generator level signals used in the feedwater control are processed by a median signal selector as discussed in Section 7.2.2.2.3.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow, preventing that channel from ultimately tripping. However, the mismatch between steam demand and feedwater flow produced by this spurious signal will actuate alarms to alert the operator of this situation in time for manual correction or the reactor will eventually trip on a low-low water level signal independent of the indicated feedwater flow.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition continues, a two out of three high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The turbine trip will result in a subsequent reactor trip. The high-high steam generator water level trip is an equipment protective trip preventing excessive moisture carryover which could damage the turbine blading.

In addition, the three element feedwater controller incorporates reset action on the level error signal such that with expected controller settings, a rapid increase or decrease in the flow signal would cause only a small change in level before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, as discussed previously.

A spurious high or low steam generator water level signal from the protection channel will be rejected by the median signal selector eliminating spurious feedwater control actions.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of primary plant component cooling water is discussed in Section 7.3.2. Load rejection and turbine trip are discussed in further detail in Section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4.1 and listed in Table 7.7-1. Excessively high power operation (which is prevented by blocking of rod withdrawal), if allowed to continue, might lead to a safety limit (Chapter 16) being reached. Before such a limit is reached, protection will be available from the RTS. At the power levels of the rod block set points, safety limits have not been reached. Therefore, these rod withdrawal stops do not come under the scope of safety-related systems and are considered as control systems.

7.2.3 Tests and Inspections

The RTS meets the intent of the testing requirements of IEEE Standard 338-1977. The testability of the system is discussed in Section 7.2.2.2.3. The test intervals are specified in Chapter 16. Written test procedures and documentation, conforming to the requirements of IEEE Standard 338-1977 will be available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22, and as discussed in Sections 7.1.2.10 and 7.2.2.2.3.

7.2.4 References for Section 7.2

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Tables for Section 7.2

TABLE 7.2-1

LIST OF REACTOR TRIPS

	Reactor Trip	Coincidence Logic	Interlocks	Comments
1.	High neutron flux (power range)	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
2.	Intermediate range high neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
3.	Source range high neutron flux	1/2	Manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset; automatic block above P-10
4.	Power range high positive neutron flux rate	2/4	No interlocks	
5.	Deleted			
6.	Overtemperature ΔT	2/3	No interlocks	
7.	Overpower ΔT	2/3	No interlocks	
8.	Pressurizer low pressure	2/3	Interlocked with P-7	Blocked below P-7
9.	Pressurizer high pressure	2/3	No interlocks	
10.	Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7

TABLE 7.2-1 (Cont)

	Reactor Trip	Coincidence Logic	Interlocks	Comments
11.	Low reactor coolant flow	2/3 per loop	Interlocked with P-7 and P-8	Low flow in one loop will cause a reactor trip when above P-8, and a low flow in two loops will cause a reactor trip when above P-7; blocked below P-7.
12.	Reactor coolant pump breakers open (anticipatory)	2/3	Interlocked with P-7	Blocked below P-7
13.	Reactor coolant pump bus undervoltage (anticipatory)	2/3	Interlocked with P-7	Low voltage permitted below P-7
14.	Reactor Coolant pump bus underfrequency (anticipatory)	2/3	Interlocked with P-7	Under frequency on two pump buses will trip all RCP breakers and cause reactor trip; blocked below P-7
15.	Low-low steam generator water level	2/3 per loop	No interlocks	
16.	Safety injection signal	Coincident with actuation of safety injection	No interlocks	Section 7.3 discusses ESF actuation conditions

TABLE 7.2-1 (Cont)

Reactor Trip	Coincidence Logic	Interlocks	Comments
17. Turbine-generator (anticipatory)			
a. Low emergency trip fluid pressure	2/3	Interlocked with P-9	Blocked below P-9
b. Turbine main stop valve close	4/4	Interlocked with P-9	Blocked below P-9
18. Manual	1/2	No interlocks	

TABLE 7.2-2

PROTECTION SYSTEM INTERLOCKS AND BLOCKS

Designation	Condition and Derivation	Function
	I. POWER ESCALATION PERMISSIVES	
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above set point	Allows manual block of source range reactor trip.
	Absence of P-6: 2/2 neutron flux (intermediate range) below set point	Defeats the block of source range reactor trip.
P-10	Presence of P-10: 2/4 neutron flux (power range) above set point	Allows manual block of power range (low set point) reactor trip.
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1).
		Blocks source range reactor trip (backup for P-6).
		Input to P-7.
	Absence of P-10: 3/4 neutron flux (power range) below set point	Defeats the block of power range (low set point) reactor trip.
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1) input to P-7.
	II. BLOCKS OF REACTOR TRIPS	
P-7	Absence of P-7: 3/4 neutron flux (power range) below set point (from P-10), and 2/2 turbine first stage pressure below set point (from P-13)	Blocks reactor trip on: Low reactor coolant flow in more than one loop, and undervoltage, underfrequency, or RCP breakers open in more than one loop, pressurizer low pressure, and pressurizer high level.
P-8	Absence of P-8: 3/4 neutron flux (power range) below set point	Blocks reactor trip on low reactor coolant flow in a single loop.

TABLE 7.2-2 (Cont)

Designation	Condition and Derivation	Function
P-9	Absence of P-9: 3/4 neutron flux (power range) below set point	Blocks reactor trip on turbine trip.
P-13	2/2 turbine first stage pressure below set point	Input to P-7.

TABLE 7.2-3

REACTOR TRIP SYSTEM INSTRUMENTATION

	Reactor Trip Signal	Range	Typical Trip Accuracy
1.	Power range high neutron flux.	1 to 120% full power	±5% (NOTE 1)
2.	Intermediate range high neutron flux	8 decades of neutron flux overlapping source range by 2 decades and including 100% power	±9.8% (NOTE 1)
3.	Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/sec)	±10.8% (NOTE 1)
4.	Power range high positive neutron flux rate	2 to 30% of full power	±1.5% (NOTE 1)
5.	Deleted		
6.	Overtemperature ΔT:	T_H 530 to 650°F T_C 510 to 630°F T_{avg} 530 to 630°F P_{przr} 1,700 to 2,500 psi F $\Delta\phi$ -50 to +50 ΔT set point 0 to 100°F	±8.0% (NOTE 2)
7.	Overpower ΔT	Refer to overtemperature T	±4.9% (NOTE 3)
8.	Pressurizer low pressure	1,700 to 2,500 psig	±25 psig
9.	Pressurizer high pressure	1,700 to 2,500 psig	±52 psig
10.	Pressurizer high water level	Entire cylindrical portion of pressurizer	±3.3% of full range between taps at design temperature and pressure

TABLE 7.2-3 (Cont)

	Reactor Trip Signal	Range	Typical Trip Accuracy
11.	Low reactor coolant flow	0 to 120% of rated flow	±2.1% (Note 4)
12.	Reactor coolant pump undervoltage	0 to 100% rated voltage	±13.6% of rated voltage
13.	Reactor coolant pump under frequency	50 to 65 Hz	±0.1 Hz
14.	Low-low steam generator water level	±6 ft from nominal full load water level	±20.2%
15.	Turbine trip		

NOTES:

1. In percent span (120% Rated Thermal Power (RTP))
2. In percent ΔT span (* °F = 150% RTP), T_{avg} -100°F, Pressure 800 psig, ±30% ΔI
3. In percent ΔT span (* °F = 150% RTP), T_{avg} -100°F, Pressure 800 psig
4. In percent span (120% flow)

*NOTE: Temperature value is based on cycle specific measurements

TABLE 7.2-4

REACTOR TRIP CORRELATION

Trip		Accident[1]	Technical Specification[2]
1. Power range high neutron flux trip (low set point)	a.	Uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition (Section 15.4.1)	2.b
	b.	Excessive heat removal due to feedwater system malfunctions (Sections 15.1.1 and 15.1.2)	
	c.	Rupture of a control rod drive mechanism housing (rod cluster control assembly ejection) (Section 15.4.8)	
2. Power range high neutron flux trip (high set point)	a.	Uncontrolled rod cluster control assembly bank withdrawal from subcritical condition (Section 15.4.1)	2.a
	b.	Uncontrolled rod cluster control assembly bank withdrawal at power (Section 15.4.2)	
	c.	Excessive heat removal due to feedwater system malfunctions (Section 15.1.1 and 15.1.2)	
	d.	Excessive load increase incident (Section 15.1.3)	
	e.	Accidental depressurization of the steam system (Section 15.1.4)	
	f.	Major secondary system pipe ruptures (Section 15.1.5)	

TABLE 7.2-4 (Cont)

Trip		Accident[1]	Technical Specification[2]
	g.	Rupture of a control rod drive mechanism housing (rod cluster control assembly ejection) (Section 15.4.8)	
3. Intermediate range high neutron flux trip		Uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition (Section 15.4.1)	5
4. Source range high neutron flux trip		Uncontrolled rod cluster control bank withdrawal from a subcritical condition (Section 15.4.1)	6
5. Power range high positive neutron flux rate trip		Rupture of a control rod drive mechanism housing (rod cluster control assembly ejection) (Section 15.4.8)	3
6. Deleted			
7. Overtemperature ΔT trip	a.	Uncontrolled rod cluster control assembly bank withdrawal at power (Section 15.4.2)	7
	b.	Uncontrolled boron dilution (Section 15.4.6)	
	c.	Loss of external electrical load and/or turbine trip (Sections 15.2.2, 15.2.3, and 15.2.5)	
	d.	Excessive heat removal due to feedwater system malfunctions (Sections 15.2.1 and 15.1.3)	
	e.	Excessive load increase incident (Section 15.1.3)	
	f.	Accidental depressurization of the reactor coolant system (Section 15.6.1)	

TABLE 7.2-4 (Cont)

Trip		Accident[1]	Technical Specification[2]
	g.	Accidental depressurization of the main steam system (Section 15.1.4)	
	h.	Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates ECCS (Section 15.6.2)	
8. Overpower ΔT trip	a.	Uncontrolled rod cluster control assembly bank withdrawal at power (Section 15.4.2)	8
	b.	Excessive heat removal due to feedwater system malfunctions (Sections 15.1.1 and 15.1.2)	
	c.	Excessive load increase incident (Section 15.1.3)	
	d.	Accidental depressurization of the main steam system (Section 15.1.4)	
9. Pressurizer low pressure trip	a.	Accidental depressurization of the reactor coolant system (Section 15.6.1)	9
	b.	Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates ECCS (Section 15.6.2)	
	c.	Major reactor coolant system pipe ruptures (LOCA) (Section 15.6.5)	
	d.	Steam generator tube rupture (Section 15.6.3)	
10. Pressurizer high pressure trip	a.	Uncontrolled rod cluster control assembly bank withdrawal at power (Section 15.4.2)	10

TABLE 7.2-4 (Cont)

Trip		Accident[1]	Technical Specification[2]
	b.	Loss of external electrical load and/or turbine trip (Sections 15.2.2, 15.2.3, and 15.2.5)	
	c.	Major rupture of a main feedwater pipe	
11. Pressurizer high water level trip	a.	Uncontrolled rod cluster control assembly bank withdrawal at power (Section 15.4.2)	11
	b.	Loss of external electrical load and/or turbine trip (Sections 15.2.2, 15.2.3, and 15.2.5)	
	c.	Major rupture of a main feedwater pipe	
12. Low reactor coolant flow	a.	Partial loss of forced reactor coolant flow (Section 15.3.1)	12
	b.	Loss of offsite power to the station auxiliaries (station blackout) (Section 15.2.6)	
	c.	Complete loss of forced reactor coolant flow (Section 15.3.2)	
	d.	Reactor Coolant Pump Shaft Seizure (Locked Rotor) (Section 15.3.3)	
13. Reactor coolant pump breaker trip		Not used nor credit taken in any accident analysis	Note 3
14. Reactor coolant pump bus undervoltage trip		Not used nor credit taken in any accident analysis	15

TABLE 7.2-4 (Cont)

Trip		Accident[1]	Technical Specification[2]
15. Reactor coolant pump bus under-frequency trip		Not used nor credit taken in any accident analysis	16
16. Low-low steam generator water level trip	a.	Loss of normal feedwater (Section 15.2.7)	13
	b.	Major rupture of a main feedwater pipe.	
17. Reactor trip on turbine trip	a.	Loss of external electrical load and/or turbine trip (Sections 15.2.2, 15.2.3, and 15.2.5)	Note 3
	b.	Loss of offsite power to the station auxiliaries (station blackout) (Section 15.2.6)	Note 3
18. Safety injection signal actuation trip	a.	Accidental depressurization of the main steam system (Section 15.1.4)	Note 4
	b.	Major secondary system pipe ruptures.	
19. Manual trip		Available for all accidents (Chapter 15)	1

NOTES:

1 References refer to accident analysis presented in Chapter 15.
2 References refer to Technical Specifications.
3 A Technical Specification is not required because this trip is not assumed to function in the accident analyses.
4 Accident assumes that the reactor is tripped at end of life, which is the worst initial condition for this case. Pressurizer low pressure is the initial trip of safety injection.

REFER TO FIGURE 7.3-6

FIGURE 7.2-1 (SH. 1 OF 18)
FUNCTIONAL DIAGRAM
INDEX AND SYMBOLS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-7

FIGURE 7.2-1 (SH. 2 OF 18)
FUNCTIONAL DIAGRAM
REACTOR TRIP SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-8

FIGURE 7.2-1 (SH. 3 OF 18)
FUNCTIONAL DIAGRAM
NUCLEAR INSTRUMENTATION &
MANUAL TRIP SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-9

FIGURE 7.2-1 (SH. 4 OF 18)
FUNCTIONAL DIAGRAM
NUCLEAR INSTRUMENTATION
PERMISSIVES & BLOCKS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-10

FIGURE 7.2-1 (SH. 5 OF 18)
FUNCTIONAL DIAGRAM
PRIMARY COOLANT SYSTEM
TRIP SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-11

FIGURE 7.2-1 (SH. 6 OF 18)
FUNCTIONAL DIAGRAM
PRESSURIZER TRIP SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-12

FIGURE 7.2-1 (SH. 7 OF 18)
FUNCTIONAL DIAGRAM
STEAM GENERATOR TRIP SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-13

FIGURE 7.2-1 (SH. 8 OF 18)
FUNCTIONAL DIAGRAM
SAFEGUARD ACTUATION SIGNALS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-14

FIGURE 7.2-1 (SH. 9 OF 18)
FUNCTIONAL DIAGRAM ROD
CONTROLS & ROD BLOCKS
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-15

FIGURE 7.2-1 (SH. 10 OF 18)
FUNCTIONAL DIAGRAM
STEAM DUMP CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-16

FIGURE 7.2-1 (SH. 11 OF 18)
FUNCTIONAL DIAGRAM
PRESSURIZER PRESSURE &
LEVEL CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-17

FIGURE 7.2-1 (SH. 12 OF 18)
FUNCTIONAL DIAGRAM
PRESSURIZER HEATER CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-18

FIGURE 7.2-1 (SH. 13 OF 18)
FUNCTIONAL DIAGRAM
FEEDWATER CONTROL & ISOLATION
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-19

FIGURE 7.2-1 (SH. 14 OF 18)
FUNCTIONAL DIAGRAM
AUXILIARY FEEDWATER
PUMPS STARTUP
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-20

FIGURE 7.2-1 (SH. 15 OF 18)
FUNCTIONAL DIAGRAM
TURBINE TRIP RUNBACKS &
OTHER SIGNALS (W REQUIREMENTS)
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-21

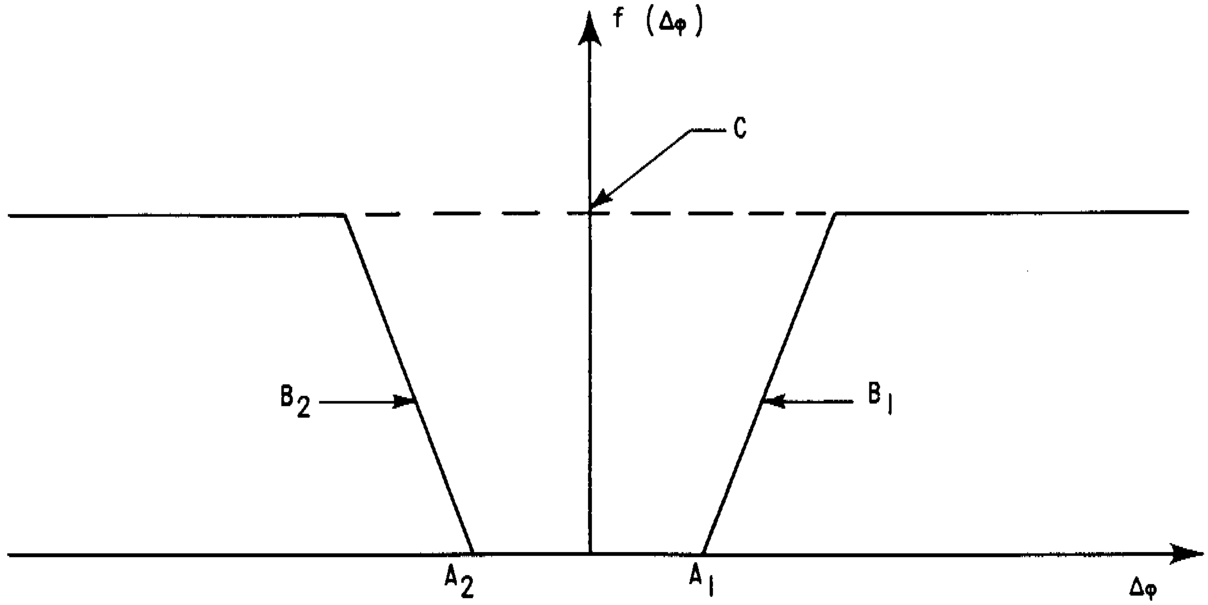
FIGURE 7.2-1 (SH. 16 OF 18)
FUNCTIONAL DIAGRAM
LOOP STOP VALVE LOGIC
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-23

FIGURE 7.2-1 (SH. 17 OF 18)
FUNCTIONAL DIAGRAM
PRESSURIZER PRESSURE
RELIEF SYSTEM (TRAIN "A")
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

REFER TO FIGURE 7.3-22

FIGURE 7.2-1 (SH. 18 OF 18)
FUNCTIONAL DIAGRAM
PRESSURIZER PRESSURE
RELIEF SYSTEM (TRAIN "B")
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT



Δφ - NEUTRON FLUX DIFFERENCE BETWEEN UPPER AND LOWER LONG ION CHAMBERS

A_1, A_2 - LIMIT OF F (Δφ) DEADBAND

B_1, B_2 - SLOPE OF RAMP; DETERMINES RATE AT WHICH FUNCTION REACHES IT'S MAXIMUM VALUE ONCE DEADBAND IS EXCEEDED

C - MAGNITUDE OF MAXIMUM VALUE THE FUNCTION MAY ATTAIN

FIGURE 7.2-2
SETPOINT REDUCTION FUNCTION FOR OVERPOWER AND OVERTEMPERATURE ΔT TRIPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

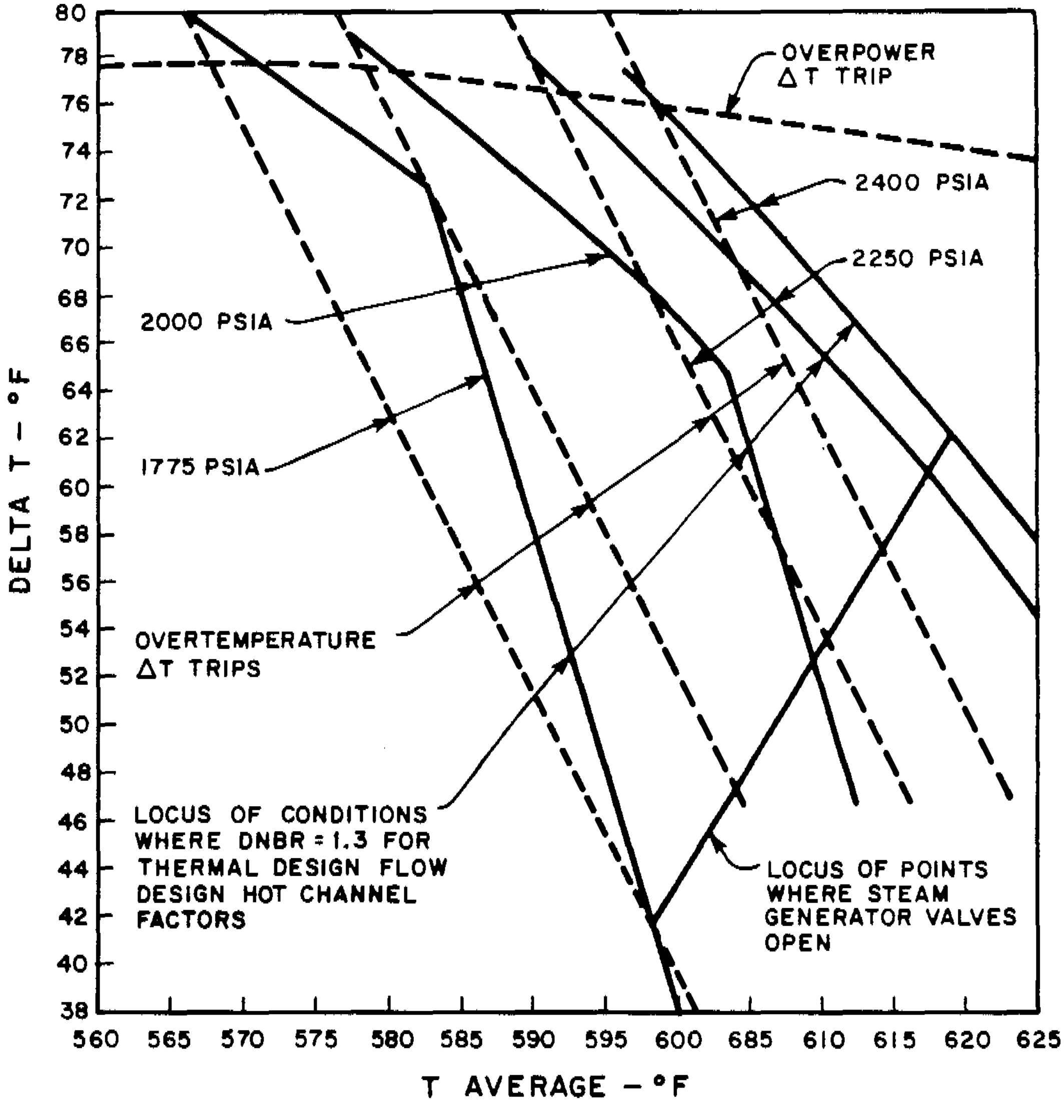


FIGURE 7.2-3
ILLUSTRATION OF OVERPOWER AND OVERTEMPERATURE ΔT PROTECTION (TYPICAL)
BEAVER VALLEY POWER STATION- UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

In addition to the requirements for a reactor trip for anticipated abnormal transients, the facility shall be provided with adequate instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features (ESF). The occurrence of a limiting fault, such as a loss-of-coolant accident (LOCA) or a main steam line break (MSLB), requires a reactor trip plus actuation of one or more of the ESF in order to prevent or mitigate damage to the core and reactor coolant system (RCS) components, and ensure containment integrity.

In order to accomplish these design objectives the engineered safety features actuation system (ESFAS) shall have proper and timely initiating signals which are to be supplied by the sensors, transmitters, and logic components making up the various instrumentation channels of the ESFAS. Figures 7.3-6, 7.3-7, 7.3-8, 7.3-9, 7.3-10, 7.3-11, 7.3-12, 7.3-13, 7.3-14, 7.3-15, 7.3-16, 7.3-17, 7.3-18, 7.3-19, 7.3-20, 7.3-21, 7.3-22 and 7.3-23 show Westinghouse Electric Corporation functional diagrams and 7.3-24, 7.3-25, 7.3-26, 7.3-27, 7.3-28, 7.3-29, 7.3-30, 7.3-31, 7.3-32, 7.3-33, 7.3-34, 7.3-35, 7.3-36, 7.3-37, 7.3-38, 7.3-39, 7.3-40, 7.3-41, 7.3-42, 7.3-43, 7.3-44, 7.3-45, 7.3-46, 7.3-47, 7.3-48, 7.3-49, 7.3-50, 7.3-51, 7.3-52, 7.3-52a, 7.3-53, 7.3-54, 7.3-55, 7.3-56, 7.3-56a, 7.3-57, 7.3-58, 7.3-59, 7.3-60, 7.3-61, 7.3-62, 7.3-63, 7.3-64, 7.3-65, 7.3-66, 7.3-67, 7.3-68, 7.3-69, 7.3-70, 7.3-71, 7.3-72, 7.3-72a, 7.3-72b, 7.3-72c, 7.3-73, 7.3-74, 7.3-75, 7.3-76, 7.3-77, 7.3-77a, 7.3-78, 7.3-79, 7.3-80, 7.3-81, 7.3-82, 7.3-82a, 7.3-82b, 7.3-82c, 7.3-83, 7.3-84, 7.3-85, 7.3-86, 7.3-86a, 7.3-87, 7.3-88, 7.3-89, 7.3-90, 7.3-91, 7.3-92, 7.3-93, 7.3-94 and 7.3-95 show logic diagrams for the ESFAS.

7.3.1 Description

The ESFAS uses selected plant parameters, determines whether or not predetermined safety limits are being exceeded and, if they are, combines the signals into logic matrices sensitive to combinations indicative of primary or secondary system boundary ruptures (Condition III or IV faults). Once the required logic combination is completed, the system sends actuation signals to the appropriate ESF components. The ESFAS meets the functional requirements of General Design Criteria (GDC) 13, 20, 27, and 38.

7.3.1.1 System Description

The ESFAS is a functionally defined system described in this section. The equipment which provides the actuation functions identified in Section 7.3.1.1.1 is listed as follows and is discussed in this section.

1. Process instrumentation and control system (Reid 1973),
2. Solid state protection system (Katz 1971),
3. Engineered safety features test cabinet (Mesmeringer 1980), and
4. Manual actuation circuits.

The ESFAS consists of two discrete portions of circuitry: 1) an analog portion consisting of three to four redundant channels per parameter or variable to monitor various Beaver Valley Power Station - Unit 2 (BVPS-2) parameters such as the RCS and steam system pressures, temperatures, and flows, and containment pressures, and 2) a portion consisting of two redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the ESF. Each actuation train is capable of actuating the minimum ESF equipment required, thereby assuring that any single failure within either of the redundant trains shall not result in the defeat of the required protective function.

The redundant concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment vessel penetrations, and analog protection racks, terminating at the redundant group of logic racks. The design meets the requirements of GDC 20, 21, 22, 23, and 24.

The variables are sensed by the analog circuitry as discussed in WCAP-7913 (Reid 1973) and in Section 7.2. The outputs from the analog channels are combined into actuation logic as shown on Figure 7.2-1, Sheets 5, 6, 7, and 8. Tables 7.3-1 and 7.3-2 give additional information pertaining to logic and function.

The interlocks associated with the ESFAS are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.1.2.

System level manual initiation from the main control board is provided for the following systems:

Safety Injection

Two switches, operating either switch will actuate.

Containment Isolation Phase A

Two switches, operating either switch will actuate.

Control Room Isolation

Two switches, operating either switch will actuate.

Steam Line Isolation

Four switches, operating two associated switches per train, simultaneously controls all steam line isolation valves (SLIVs) and bypass valves.

Containment Spray and Containment Isolation Phase B

Four switches, actuation will occur if two associated controls are operated simultaneously. For the transfer of emergency core cooling system (ECCS) injection to the recirculation mode, refer to Sections 6.3.2.8 and 7.6.5 and Table 6.3-7.

7.3.1.1.1 Function Initiation

The specific functions which rely on the ESFAS for initiation are:

1. A reactor trip, provided one has not already been generated by the reactor trip system.

2. Cold leg injection isolation valves, which are opened to align the charging pumps for high pressure safety injection into the cold legs of the RCS.

3. Charging pumps, low head safety injection (LHSI) pumps, and associated valving, which provide emergency makeup water to the cold legs of the RCS following a LOCA.

4. Automatic transfer of ECCS injection to recirculation on extreme low refueling water storage tank (RWST) level.

5. Pumps and valves, which serve as part of the heat sink and as part of the heat sink for containment cooling, for example, service water pumps.

6. Motor-driven auxiliary feedwater pumps and associated valves and the valves required to initiate a steam supply to the turbine-driven auxiliary feedwater pump.

7. Containment isolation Phase A, whose function is to prevent fission product release. (Isolation of all lines not essential to reactor protection.)

8. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled RCS cooldown.

9. Main feedwater line isolation, as required, to prevent or mitigate the effects of excessive cooldown.

10. Start-up of the emergency diesel generators to assure the backup supply of power to emergency and supporting systems components.

11. Isolation of the main control room air ducts to meet control room occupancy requirements and start of the emergency ventilation fans to pressurize the control room.

12. Containment quench and recirculation spray systems, which performs the following functions:

    a. Initiate quench and recirculation sprays to reduce containment pressure and temperature following a LOCA or MSLB accident inside containment.

b. Initiates containment isolation Phase B which, except for ESF lines penetrating containment, isolates the containment following a LOCA, or an MSLB or feedwater line break within containment to limit radioactive releases. (Section 6.2.4 considers isolation valves in further detail.)

13. Sequencers for loss of offsite power (LOOP) or safety injection (Chapter 8).

7.3.1.1.2 Analog Circuitry

The process analog sensors and racks for the ESFAS are discussed in WCAP-7913 (Reid 1973). Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures, as well as the measurement and signal transmission considerations. Other considerations discussed are automatic calculations, signal conditioning and location, and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in Chapter 5, Reactor Coolant System and Connected Systems. The secondary system sensor locations are shown on the steam system flow diagrams given in Chapter 10.

There are four instrument lines which penetrate the containment and which are required to remain functional following a LOCA or MSLB inside containment. These lines sense the pressure of containment atmosphere on the inside and are connected to pressure transmitters on the outside. Signals from these transmitters can initiate safety injection and containment isolation on Hi-1 containment pressure, and initiate main steam line isolation on Hi-2 containment pressure. These signals also, upon Hi-3 containment pressure, produce the automatic signal to initiate containment depressurization system spray and provide for post-accident monitoring (PAM) of containment pressure. In view of these functions, these lines do not have automatic isolation valves since it is essential that the lines remain open and not be isolated following an accident. This system is described in Section 6.2.4.

7.3.1.1.3 Digital Circuitry

The ESF logic racks are discussed in detail in WCAP-7488-L (Katz 1971). The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Katz (1971) also discusses certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, and considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown on Figure 7.2-1, Sheets 5 (Tavg), 6 (Pressurizer Pressure), 7 (Low Steam Line Pressure), 8 (Engineered Safety Features Actuation), and 14 (Auxiliary Feedwater).

To facilitate ESF actuation testing, two cabinets (one per train) are provided which enable operation, to the maximum extent practical, of safety features loads on a group by group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.2.

7.3.1.1.4 Final Actuation Circuitry

The outputs of the solid-state protection system (SSPS) (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are listed as follows:

1. Safety injection system pump and valve actuators. (Chapter 6 provides flow diagrams and additional information).
2. Containment isolation Phase A and Phase B (Chapter 6.)
3. Automatic transfer of ECCS injection to recirculation on extreme low RWST level.
4. Service water pump and valve actuators (Chapter 9).
5. Auxiliary feedwater pumps start (Chapter 10).
6. Emergency diesel generators start (Chapter 8).
7. Feedwater isolation (Chapter 10).
8. Main control room ventilation isolation valve and damper actuators (Chapter 6).
9. Steam line isolation valve actuators (Chapter 10).
10. Containment quench spray, recirculation spray, and valve actuators (Chapter 6).

If an accident is assumed to occur coincident with a LOOP, the ESF loads are sequenced onto the emergency diesel generators to prevent overloading them. This sequence is discussed in Chapter 8. The design meets the requirements of GDC 35.

7.3.1.1.5 Support Systems

The following systems are required for support of the ESF:

1. Service water - heat removal (Section 9.2.1).
2. Safety-related ventilation systems (Section 9.4).
3. Electrical power distribution systems (Section 8.3).
4. Emergency diesel generator fuel oil system (Section 9.5.4).

7.3.1.2 Design Bases Information

The functional diagrams presented on Figure 7.2-1, Sheets 5, 6, 7, and 8 provide a graphic outline of the functional logic associated with requirements for the ESFAS. Requirements for the ESF systems are given in Chapter 6. Given by the following is the design bases information required by the Institute of Electrical and Electronics Engineers (IEEE) Standard 279-1971.

7.3.1.2.1 Generating Station Conditions

The following is a summary of those generating station conditions requiring protective action from the ESFAS to mitigate an accident (for transient termination, refer to Section 7.2).

1. Primary System:

    a. Rupture in small pipes or cracks in large pipes,

    b. Rupture of a reactor coolant pipe (LOCA), and

    c. Steam generator tube rupture.

2. Secondary System:

    a. Minor secondary system pipe breaks resulting in steam release rates equivalent to a single dump, relief, or safety valve,

    b. Rupture of a major steam pipe, and

    c. Rupture of a major feedwater pipe.

7.3.1.2.2 Generating Station Variables

The following list summarizes the generating station variables required to be monitored for the automatic initiation of ESF during each accident identified in the preceding section. Requirements for PAM are given in Table 7.5-1.

1. Primary system accidents:

    a. Pressurizer pressure,

    b. RWST water level, and

    c. Containment pressure (not required for steam generator tube rupture).

2. Secondary system accidents:

    a. Pressurizer pressure,

    b. Steam line pressures and pressure rates,

c. Containment pressure, and

d. Steam generator water level.

7.3.1.2.3 Limits, Margins, and Levels

Prudent operational limits, available margins, and set points before onset of unsafe conditions requiring protective action are discussed in Chapters 15 and 16.

7.3.1.2.4 Abnormal Events

The malfunctions, accidents, or other unusual events which could physically damage protection system components or could cause environmental changes are as follows:

1. LOCA (Chapter 15),

2. Secondary system accidents (Chapter 15),

3. Earthquakes (Chapters 2 and 3),

4. Fire (Section 9.5.1),

5. Missiles (Section 3.5),

6. Flood (Chapters 2 and 3),

7. Environmental transients (temperature/pressure/humidity) due to ventilation system failures (Section 3.11), and

8. High energy line breaks (Section 3.6).

7.3.1.2.5 Minimum Performance Requirements

Minimum performance requirements are as follows:

1. System response times.

   The ESFAS response time is defined as the interval required for the ESF sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed set points. The ESF sequence is initiated by the output of the ESFAS, which is by the operation of the dry contacts of the slave relays (600 series relays) in the output cabinets of the SSPS. The list of response times which follows, includes the interval of time which will elapse between the time the parameter, as sensed by the sensor, exceeds the safety set point and the time the SSPS slave relay dry contacts are operated. These values are maximum allowable values consistent with the safety analyses and the Licensing Requirements Manual and are systematically verified during plant preoperational start-up tests. For the overall ESF response time, refer to Table 3.3.2-1 of the

Licensing Requirements Manual. In a similar manner for the overall RTS instrumentation response time, refer to Table 3.3.1-1 of the Licensing Requirements Manual.

The ESFAS is always capable of having response time tests performed, using the same methods as those tests performed during the preoperational test program or following significant component changes.

a. Typical maximum allowable time delays in generating the actuation signal for loss-of-coolant accident (LOCA) protection are:

(1)	Pressurizer pressure	1.0 second
(2)	RWST water level	1.5 seconds
(3)	Containment pressure	1.5 seconds

b. Typical maximum allowable time delays in generating the actuation signal for main steam line break (MSLB) protection are:

(1)	Steam line pressure	1.0 second
(2)	Steam line pressure rate	1.0 second
(3)	Pressurizer pressure	1.0 second
(4)	High containment pressure for closing main steam line stop valves (Hi-2)	1.5 seconds
(5)	Actuation signals for auxiliary feedwater pumps	2.0 seconds

2. Systems accuracies.

a. Typical accuracies required for generating the required actuation signals for LOCA are:

(1)	Pressurizer pressure (uncompensated)	±25 psi
(2)	Containment pressure	±2.9 percent of full scale
(3)	RWST water level	±5.7 percent of span

b. Typical accuracies required in generating the required actuation signals for MSLB protection are given:

(1)	Steam line pressure	±8.3 percent of span
(2)	Steam generator water level	±18.2 percent of span

(3) Pressurizer pressure ±25 psig

(4) Containment pressure signal ±2.9 percent of span

3. Ranges of sensed variables to be accommodated until conclusion of protective action is assured.

   a. Typical ranges required in generating the actuation signals for LOCA protection are given:

      (1) Pressurizer pressure 1,700 to 2,500 psig

      (2) Containment pressure 0 to 115 percent of containment design pressure

      (3) RWST water level 0 to 144 inches

   b. Typical ranges required in generating the required actuation signals for MSLB protection are given:

      (1) Steam line pressure (from which steam line pressure rate is also derived) 0 to 1,300 psig

      (2) Steam generator water level 0 to 144 inches

      (3) Containment pressure 0 to 115 percent of containment design pressure

7.3.1.3 Final System Drawings

Functional block diagrams, electrical elementaries, and other drawings, as required to assure electrical separation and to perform a safety review, are provided in the drawing supplement (Section 1.7) prepared by Stone & Webster Engineering Corporation. These will include Westinghouse process block diagrams, Westinghouse nuclear instrumentation system block diagrams, and Westinghouse safeguards test cabinets drawings. The functional logic diagram is shown on Figure 7.2-1.

7.3.2 Analysis

Failure modes and effects analyses (FMEAs) have been performed on ESF systems equipment within the Westinghouse scope of supply. The interfaces between the Westinghouse ESF systems and the BVPS-2 ESF systems have been analyzed and found to meet the interface requirements specified in WCAP-8760 (Mesmeringer 1980). The BVPS-2 ESF systems, although not identical, have been designed to equivalent safety design criteria.

For balance of plant (BOP) safety systems, FMEAs have also been performed on the instrumentation and controls and electrical power portions of those systems used to initiate the operation of the ESF systems and their essential auxiliary supporting systems (Table 7.3-4). The analyses were made to assure that each system satisfies the applicable design criteria and will perform as intended during all BVPS-2 operations and accident conditions for which its function is required.

The ESF and supporting systems are designed so that a LOOP, the loss of cooling water to vital equipment, a plant load rejection, or a turbine trip will not prevent the completion of the safety function under postulated accidents and failures. Evaluation of the individual and combined capabilities of the ESF and supporting systems can be found in Chapters 6 and 15.

Compliance with the IEEE Standards, Regulatory Guides, and GDC is as follows: discussion of the GDC is provided in various sections of Chapter 7 where a particular GDC is applicable; applicable GDC include Criteria 13, 20, 21, 22, 23, 24, 25, 26, 27, 28, 35, 37, 38, 40, 43, and 46; compliance with certain IEEE Standards is presented in Sections 7.1.2.6, 7.1.2.8, 7.1.2.9, and 7.1.2.10; compliance with Regulatory Guides is discussed in Section 7.1.

7.3.2.1 Failure Mode and Effects Analyses

The systematic, organized, analytical procedure for identifying the possible modes of failure and evaluating their consequences is called a FMEA. Its purpose is to demonstrate and verify how the GDC of 10 CFR 50 Appendix A and IEEE Standard 279-1971 requirements are satisfied. The FMEAs that are performed on the Class 1E electric power and instrumentation and controls portions of the safety-related auxiliary supporting systems also determine if they will meet the single failure criteria.

The FMEA for a BOP safety-related system is produced in the form of a computerized tabulation that identifies the component, its failure mode, the method of failure detection, and its effect on the safety-related system. This tabulation is derived from the fault tree analysis (FTA).

The FTA is a technique by which failures that can contribute to an undesired event are systematically and deductively organized from a top event down to subordinate events. It is pictorially represented by rectangular blocks connected via flow lines to logic gates, all placed together in a tree-shaped configuration called a fault tree diagram.

The fault tree diagram identifies all the failure modes that are significant to the failure of the BOP safety-related system, the failure paths from the failed items up through the fault tree to a single top failure event, and any single failures that may result in the failure of the system to perform its intended safety function. It also provides a visual display of how the system can malfunction.

When the event blocks and logic gates on the fault tree diagram have been assigned unique computer-readable codes, they can be computer-processed and printed out in a standard format as an auditable, permanent record called the FMEA.

The FMEAs for the BOP safety-related systems of BVPS-2 are provided in a separate document entitled Failure Modes and Effects Analysis (Section 1.7).

7.3.2.2 Compliance with IEEE Standard 279-1971

The discussion that follows shows that the ESFAS complies with IEEE Standard 279-1971.

7.3.2.2.1 Single Failure Criteria

The discussion presented in Section 7.2.2.2.3 is applicable to the ESFAS, with the following exception:

In the ESF systems, a de-energization of the bistable will call for actuation of ESF equipment controlled by the specific bistable that lost power (containment spray and RWST extreme low bistables excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in Section 7.6 and in Chapter 8. For containment spray and RWST extreme low bistables, the final bistables are energized to trip to avoid spurious actuation. In addition, manual containment spray requires a simultaneous actuation of two manual controls. This is considered acceptable because spray actuation on Hi-3 containment pressure signal provides automatic initiation of the system via protection channels, meeting the criteria in IEEE Standard 279-1971. Moreover, two sets (two switches per set) of the containment spray manual initiation switches are provided to meet the requirements of IEEE Standard 279-1971. Also, it is possible for all ESF equipment (valves, pumps, etc) to be individually manually-actuated from the main control board. Hence, a third mode of containment spray initiation is available. The design meets the requirements of GDC 21 and 23.

7.3.2.2.2 Equipment Qualification

The subject of equipment qualification is addressed in Sections 3.10 and 3.11.

7.3.2.2.3 Channel Independence

The discussion presented in Section 7.2.2.2.3 is applicable. The ESF slave relay outputs from the solid state logic protection cabinets are redundant, and the actuation signals associated with each train are energized up to and including the final actuators by the separate ac power supplies which power the logic trains.

7.3.2.2.4 Control and Protection System Interaction

The discussions presented in Section 7.2.2.2.3 are applicable.

7.3.2.2.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of the system testability in Section 7.2.2.2.3 are applicable to the sensors, analog circuitry, and logic trains of the ESFAS.

The following discussions cover those areas in which the testing provisions differ from those for the RTS.

Testing of Engineered Safety Features Actuation Systems

The ESFAS are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program meets the requirements of GDC 21, 37, 40, and 43 and Regulatory Guide 1.22, as discussed in Section 7.1.2.4. The tests described herein, and further discussed in Section 6.3.4, meet the requirements on testing of the ECCS, as stated in GDC 37, except for the operation of those components that will cause an actual safety injection. The test demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources, and the operation of associated cooling water systems. The charging pumps and LHSI pumps are started and operated and their performance verified in a separate test discussed in Section 6.3.4. When the pump tests are considered in conjunction with the ECCS test, the requirements of GDC 37 on testing of the ECCS are met as closely as possible without causing an actual safety injection.

Testing described in Sections 6.3.4, 7.2.2.2.3, and 7.3.2.2.3 provides complete periodic testability during reactor operation of all logic and components associated with the ECCS. This design meets the requirements of Regulatory Guide 1.22, as discussed in the previous sections. The program is as follows:

1. Prior to initial plant operations, ESF system tests will be conducted.

2. Subsequent to initial start-up, ESF system tests will be conducted during each regularly scheduled refueling outage.

3. During on-line operation of the reactor, all of the ESF analog and logic circuitry will be fully tested. In addition, essentially all of the ESF final actuators will be fully tested. The remaining few final actuators whose operation is not compatible with continued on-line plant operation will be checked by means of continuity testing.

Performance Test Acceptability Standard for Safety Injection Signal and Automatic Signal for Containment Depressurization Actuation Generation

During reactor operation, the basis for ESFAS acceptability will be the successful completion of the overlapping tests performed on the initiating system and the ESFAS (Figure 7.3-3). Checks of process indications verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of these circuits through and including the logic input relays except for the input relays during the solid state logic testing. Solid state logic testing also checks the digital signal path from and including logic input relay contacts through the logic matrices and master relays and perform continuity tests on the coils of the output slave relays. Final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing plant upset. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication, and by visual observation that the appropriate pump breakers close and automatic valves have completed their travel.

The basis for acceptability for the ESF interlocks will be control board indication of proper receipt of the signal upon introducing the required input at the appropriate set point.

Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed in accordance with the Technical Specifications. Testing, including the sensors, is also performed during scheduled BVPS-2 shutdown for refueling.

Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the on-line portion of the testing program. The guidelines used in developing the circuitry and procedures are:

1. The test procedures must not involve the potential for damage to any BVPS-2 equipment,

2. The test procedures must minimize the potential for accidental tripping of BVPS-2 systems, and

3. The provisions for on-line testing must minimize complication of ESF actuation circuits so that their reliability is not degraded.

Description of Initiation Circuitry

Several systems (listed in Section 7.3.1.1.1) comprise the total ESF system, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in Section 7.3.1.1.1) are initiated by a common signal (safety injection signal) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, primary component cooling water, and service water is initiated by the safety injection signal.

Each function is actuated by a logic circuit, which is duplicated for each of the two redundant trains of ESF initiation circuits.

The output of each of the initiation circuits consists of a master relay, which drives slave relays for contact multiplication as required. The master and slave relays are mounted in the ESFAS cabinets, designated Train A and Train B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor-operated valve (MOV) contactors, solenoid-operated valves, emergency diesel generator starting, etc.

Analog Testing

Analog testing is identical (except as noted) to that used for reactor trip circuitry and is described in Section 7.2. An exception to this is containment quench spray, which is energized to actuate two out of four and reverts to two out of three when one channel is in test.

Solid State Logic Testing

Except for containment spray channels, solid-state logic testing is the same as that discussed in Section 7.2. During logic testing of one train, the other train can initiate the required ESF function (Katz 1971). Katz (1971) gives additional information on solid-state logic testing.

Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. Slave relays do not operate because of the reduced voltage.

The ESFAS final actuation device or actuated equipment testing will be performed from the engineered safeguards test cabinets. These cabinets are normally located near the SSPS equipment. One test cabinet is provided for each of the two protection trains, Trains A and B. Each cabinet contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators have been made such that groups of devices or actuated equipment can be operated individually during BVPS-2 operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its safeguards position.

During this last procedure, close communication between the main control room operator and the operator at the test panel is required. Prior to the energizing of a slave relay, the operator in the main control room assures that plant conditions will permit operation of the equipment that is to be actuated by the relay. After the test panel operator has energized the slave relay, the main control room operator observes that all equipment has operated, as indicated by appropriate indicating lamps, monitor lamps, and annunciators on the main control board, and using a prepared checklist, records all operations. This operator then resets all devices and prepares for operation of the next slave relay-actuated equipment.

By means of the procedure outlined previously, all ESF devices actuated by the ESFAS initiation circuits, with the exceptions noted in Section 7.1.2.4 under a discussion of Regulatory Guide 1.22, are operated by the automatic circuitry.

Actuator Blocking and Continuity Test Circuits

Those few final actuation devices that cannot be designed to be actuated during BVPS-2 operation (discussed in Section 7.1.2.4) have been assigned to slave relays, for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations and continuity of the electrical circuits associated with the final devices' control, are checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices' control circuit cabling, control voltage, and the devices' actuation solenoids. Interlocking prevents blocking the output from more than one output relay in a protection train at a time. Interlocking between Trains A and B is also provided to prevent continuity testing in both trains simultaneously. The redundant device associated with the protection train not under test will be available in the event protective action is required. If an accident occurs during testing, the automatic actuation circuitry will override testing as noted previously. One exception to this is that if the accident occurs while testing a slave relay whose output must be blocked, those few final actuation devices associated with this slave relay will not be overridden; however, the redundant devices in the other train would be operational and would perform the required safety function. Actuation devices to be blocked are identified in Section 7.1.2.4.

The continuity test circuits for those components that cannot be actuated on-line are verified by providing indicating lights on the safeguards test racks.

The typical schemes for blocking operation of selected protection function actuator circuits are shown on Figure 7.3-4 as Details A and B. The schemes operate as explained by the following and are duplicated for each safeguards train.

Detail A shows the circuit for contact closure for protection function actuation. Under normal BVPS-2 operation, and equipment not under test, the test lamp DS* for the various circuits will be energized. Typical circuit path will be through the normally closed test relay contact K8* and through test lamp connections 1 to 3. Coil X2 will be capable of being energized for protection function actuation upon closure of solid-state logic output relay contact K*. Coil X2 is typical for a breaker closing auxiliary coil, motor starter master coil, coil of a solenoid valve, auxiliary relay, etc. When the contact K8* is opened to block energizing of coil X2, the white lamp is de-energized and the slave relay

K* may be energized to perform continuity testing. This continuity testing is verified by depressing test lamp DS* and observing that the lamp lights through connection 2 (Contact K8* open) through solid-state logic output relay contact K* (now closed) and finally through actuator coil X2. Sufficient current will flow in the circuit to cause the lamp to glow but insufficient to cause the actuator coil X2 to operate. To verify operability of the blocking relay in both blocking and restoring normal service, open the blocking relay contact in series with lamp connections - the test lamp should be de-energized; close the blocking relay contact in series with the lamp connections - the test lamp should now be energized. This test verifies that the circuit is now in its normal, that is, operable condition.

Detail B shows the circuit for contact opening for protection function actuation. Under normal BVPS-2 operation, and equipment not under test, the white test lamp DS*, for the various circuits will be energized, and green test lamp DS* will be de-energized. Typical circuit path for white lamp DS* will be through the normally closed solid-state logic output relay contact K* and through test lamp connections 1 to 3. Coil Y2 will be capable of being de-energized for protection function actuation upon opening of solid-state logic output relay contact K*. Coil Y2 is typical for a solenoid valve coil, auxiliary relay, etc. When the contact K8* is closed to block de-energizing of coil Y2, the green test lamp is energized and the slave relay K* may be energized to verify operation (opening of its contacts). To verify operability of the blocking relay in both blocking and restoring normal service, close the blocking relay contact to the green lamp - the green test lamp should be energized; open this blocking relay contact - the green test lamp should be de-energized, which verifies that the circuit is now in its normal (that is, operable) condition.

Time Required for Testing

It is estimated that analog testing can be performed at a rate of several channels per hour. Logic testing of Train A or B can be performed in less than 2 hours. Testing of actuated components (including those which can only be partially tested) will be a function of main control room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be closed and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time, the redundant devices in the other trains would be functional.

Summary of On-Line Testing Capabilities

The procedures described provide capability for checking completely from the process signal to the logic cabinets and from there to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc, including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those few devices whose operation could adversely affect BVPS-2 or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device a continuity test of the individual control circuits is performed.

The procedures require testing at various locations:

1. Analog testing and verification of bistable set points are accomplished at the process analog racks. Verification of bistable relay operation is done by the main control room status lights.

2. Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

3. Testing of pumps, fans, and valves is done at a test panel located in the vicinity of the logic racks, in combination with the main control room operator.

4. Continuity testing for those circuits that cannot be operated is done at the same test panel mentioned in item 3.

The reactor coolant pump (RCP) essential service isolation valves consist of the isolation valves for the component cooling water (CCW) and the seal water return header. For the discussion of testing limitations of these valves, refer to Section 7.1.2.4, Items 7 and 9.

Containment spray system tests will be performed periodically. The pump tests will be performed with the isolation valves in the spray supply lines at the containment and spray chemical additive tank closed. The valves tests are performed with the pump stopped. During this testing, automatic actuation circuitry will override testing.

Testing During Shutdown

The ECCS tests will be performed in accordance with the Surveillance Frequency Control Program with the RCS isolated from the ECCS by closing the appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the ECCS. This is in compliance with GDC 37.

7.3.2.2.6 Manual Resets and Blocking Features

The manual reset feature associated with containment spray actuation is provided in the SSPS design for two basic purposes: 1) the feature permits the operator to start an interruption procedure of automatic containment in the event of false initiation of an actuate signal, and 2) although spray system performance is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

It is most important to note that manual control of the spray system does not occur, once actuation has begun, by just resetting the associated logic devices alone. Components will seal in (latch) so that removal of the actuate signal, in itself, will neither cancel nor prevent completion of protection action, nor provide the operator with manual override of the automatic system by this single action. In order to take complete control of the system to interrupt its automatic performance, the operator must deliberately unlatch relays which have sealed in the initial actuate signals in the associated motor control center in addition to tripping the pump motor circuit breakers, if stopping the pumps is desirable or necessary.

The feature of manual reset associated with containment spray does not perform bypass function. It is merely the first of several manual operations required to take control from the automatic system or interrupt its completion should such an action be considered necessary.

In the event that the operator anticipates system actuation and erroneously concludes that it is undesirable or unnecessary and imposes a standing reset condition in one train (by operating and holding the corresponding reset switch at the time the initiate signal is transmitted), the other train will automatically carry the protective action to completion. In the event that the reset condition is imposed simultaneously in both trains at the time the initiate signals are generated, the automatic sequential completion of system action is interrupted and control will have been taken over by the operator. Manual takeover will be maintained, even though the reset switches are released, if the original initiate signal exists. Should the initiate signal then clear and return again, automatic system actuation will repeat.

Note also that any time delays imposed on the system action are to be applied after the initiating signals are latched.

The manual block features associated with pressurizer and steam line safety injection signals provide the operator with the means to block initiation of safety injection during BVPS-2 start-up and shutdown. These block features meet the requirements of Paragraph 4.12 of IEEE Standard 279-1971 in that automatic removal of the block occurs when plant conditions require the protection system to be functional.

7.3.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62)

The ESFAS agrees with Regulatory Guide 1.62 with the following clarification:

1. Manual initiation at the system level is interpreted to mean no more than three operator actions will be required to initiate at least one train, division, or channel of final actuation devices, including support systems.

2. Engineering judgement will be exercised to assure that a minimum of operator actions are required to achieve system level manual initiation without unnecessarily jeopardizing the return to operation of the power plant. For protective actions that significantly affect return to operation, or for those protective actions that may, if inadvertently initiated, result

in a less safe plant condition, operator actions on two control devices will be required.

3. Designs requiring more than two operator actions per train, division, or channel to achieve protective action are to be limited to those actions required only in the long term and will be evaluated on a case-by-case basis.

4. All equipment that contributes to the protective action will be initiated at the system level.

5. Switches for manual initiation will be located in the main control room in such a manner as to permit deliberate expeditious action by the operator.

6. Equipment common to both manual and automatic initiation will be minimized. Where manual and automatic action sequencing functions and interlocks that contribute to the protective action are common, component or channel level initiation will also be provided in the main control room.

7. Manual initiation portions of the protection system will meet the single failure criterion.

8. Manual initiation portions of the protection system will not impair the ability of the automatic system to meet the single failure criterion.

9. Manual initiation portions of the protective system are designed such that once initiated, a protective action at the system level (indication of the final actuation device associated with a given protective function) goes to completion.

   Having gone to completion (that is, once sufficient breakers are closed or sufficient MOVs or other actuators are operated), a device shall only be returned to its pre-initiation status by deliberate operator action. This action shall be similar in nature for all protection systems.

   This design is in compliance with Paragraph 4.16 of IEEE Standard 279-1971.

10. In addition, manual initiation is provided to allow the operator to take early action based on observation of plant parameters. It is not to be treated as a backup to automatic features. Operator actions will not be required to compensate for single failures.

This discussion represents an interpretation of the stated position of Regulatory Guide 1.62 with regard to philosophy and definition of terms. As such, it describes, in as much detail as required, exactly how the subject guide will be implemented. It does not take any exceptions to the stated position in the regulatory guide.

The ESFAS agrees with Regulatory Guide 1.62 with the following additional clarification:

There are three individual main steam stop valve control devices (one per loop) mounted on the main control board. Each device when actuated will isolate one of the main steam lines. In addition, there will be two sets (two momentary controls per set) of system level control devices, with either set capable of actuating all steam lines at the system level.

No exception to the requirements of IEEE Standard 279-1971 has been taken in the manual initiation circuit of safety injection. Although Paragraph 4.17 of IEEE Standard 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, IEEE Standard 279-1971 does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety injection functions associated with one actuation train (for example, Train A) shares portions of the automatic initiation circuitry logic of the same logic train; however, a single failure in shared functions does not defeat the protective action of the redundant actuation train (for example, Train B). A single failure in shared functions does not defeat the protective action of the safety function. It is further noted that the sharing of the logic by manual and automatic initiation is consistent with the system level action requirements of IEEE Standard 279-1971, Paragraph 4.17, and consistent with the minimization of complexity.

For the transfer of ECCS injection to the recirculation mode, refer to Sections 6.3.2.8 and 7.6.5, and Table 6.3-7.

7.3.2.3 Further Considerations

7.3.2.3.1 Instrument Air and Component Cooling

In addition to the considerations given previously, a loss of reactor plant instrument air or loss of CCW to vital equipment has been considered. For the discussion concerning loss of component cooling water to the RCPs, refer to Section 7.1.2.4 under Item 7, which addresses closure of the CCW isolation valves. Loss of instrument air does not prevent the operation of the minimum systems necessary for hot standby or cold shutdown, assuming limited operator action outside the main control room, as well as operator control of the control room. Furthermore, all pneumatically-operated valves and controls will assume a safe operating position upon loss of instrument air. It is also noted that, for conservatism during the accident analysis (Chapter 15), credit is not taken for the instrument air systems nor for any control system benefit.

Circuitry is not provided which directly trips the RCPs on a loss of primary CCW. The BOP design provides for alarms in the main control room whenever CCW is lost. The RCPs can run about 10 minutes after a loss of CCW. This provides adequate time for the operator to correct the problem or trip the plant if necessary.

7.3.2.3.2 Auxiliary Feedwater System

The auxiliary feedwater system (AFWS) complies with the intent of NUREG-0737 (USNRC 1980), Action Item II.E.1.2. For the description of the AFWS, refer to Section 10.4.9.

The two motor-driven AFW pumps are started automatically by any one or more of the following conditions. Starting the motor-driven AFW pumps will cause the blowdown isolation and sampling isolation valves for all steam generators to close.

1. Safety injection,

2. Two out of three low-low level in any two steam generators (from SSPS),

3. Automatic trip of main feedwater pumps,

4. AMSAC Auto Start.

The turbine-driven AFW pump is started automatically by any one or more of the following conditions. Starting the turbine driven AFW pump will cause the blowdown isolation and sampling isolation valves for all steam generators to close.

1. Safety injection,

2. Two out of three low-low level in any steam generator (from SSPS),

3. Two out of three reactor coolant pump bus undervoltage, or

4. AMSAC Auto Start.

7.3.2.4 Summary

The ESFAS detects Condition III and IV faults and generates signals which actuate the ESF. The system senses the accident condition and generates the signal actuating the protection function reliably and within a time determined by and consistent with the accident analysis in Chapter 15.

Much longer times are associated with the actuation of the mechanical and fluid system equipment related with the ESF. This includes the time required for switching, bringing pumps and other equipment to speed, and the time required for them to take load. For the maximum time duration associated with ESF load sequencing, refer to Section 8.3.

Operating procedures require that the complete ESFAS normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode or bypass mode in the case of containment spray.

Containment isolation satisfies the intent of NUREG-0737 (USNRC 1980), Action Item II.E.4.2, Position 4, by providing containment isolation either by a safety injection signal or by a high containment pressure signal, as shown in Table 7.3-2.

7.3.2.4.1 Loss-of-Coolant Accident Protection

By analysis of LOCAs and in system tests it has been verified that except for very small coolant system breaks, which can be protected against by the charging pumps followed by an orderly shutdown, the effects of various LOCAs are reliably detected by the low pressurizer pressure signal and the ECCS is actuated in time to prevent or limit core damage.

For large RCS breaks, the passive accumulators inject first because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active ECCS phase.

Hi-1 containment pressure also actuates the ECCS. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break, that is, the ESFAS detects the leakage of the coolant into the containment. Section 7.3.1.2.5 gives the time between the occurrence of the low pressurizer pressure signal or the Hi-1 containment pressure signal and the generation of the actuation signal.

Containment spray will provide additional emergency cooling of containment and also limit fission product release upon sensing elevated containment pressure (Hi-3) to mitigate the effects of a LOCA.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is assumed to be about 1.0 second, well within the capability of the protection system equipment. However, this time is short compared to that required for start-up of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss-of-coolant.

7.3.2.4.2 Main Steam Line Break Protection

The ECCS is also actuated in order to protect against an MSLB. Section 7.3.1.2.5 gives the time between occurrence of low steam line pressure, high containment pressure (for breaks in containment), or high steam line pressure rate and generation of the actuation signal. Analysis of MSLB accidents, assuming this delay for signal generation, shows that the ECCS is actuated for an MSLB in time to limit or prevent further core damage for MSLB cases.

Additional protection against the effects of MSLB is provided by feedwater isolation, which occurs upon actuation of the ECCS. Feedwater isolation is initiated in order to prevent excessive cooldown of the reactor vessel and thus protect the RCS boundary.

Supplementary protection against a MSLB accident is provided by closure of all SLIVs in order to prevent uncontrolled blowdown of all steam generators. The generation of the protection system signal is again short compared to the time to trip the fast acting SLIVs which are designed to close in less than approximately 5 seconds.

In addition to actuation of the ESF, the effect of an MSLB accident also generates a signal resulting in a reactor trip on overpower ΔT or following ECCS actuation. The core reactivity is further reduced by the highly borated water injected by the ECCS.

The analyses in Chapter 15 of the MSLB accidents and an evaluation of the protection system instrumentation and channel design show that the ESFAS are effective in preventing or mitigating the effects of an MSLB accident.

7.3.3 References for Section 7.3

Katz, D. N. 1971. Solid-State Logic Protection System Description. WCAP-7488-L (Proprietary) and WCAP-7672. (Instrumentation operation details apply to three loop plants; however, block diagram may not.)

Mesmeringer, J. C. 1980. Failure Modes and Effects Analysis of the Engineered Safety Features Actuation System. WCAP-8760.

Reid, J. B. 1973. Process Instrumentation for Westinghouse Nuclear Steam Supply System. WCAP-7913 (Instrumentation operation details apply to three loop plants; however, block diagrams may not).

U.S. Nuclear Regulatory Commission 1980. Clarification of TMI Action Plan Requirements. NUREG-0737.

Tables for Section 7.3

TABLE 7.3-1

INSTRUMENT OPERATING CONDITIONS FOR
ENGINEERED SAFETY FEATURES

Functional Unit	No. of Channels	No. of Channels to Trip
Safety Injection		
Manual	2	1
Containment pressure (Hi-1)	3	2
Low compensated steam (lead-lag compensated)	3/steam line	2/steam line any steam line
Pressurizer low pressure*	3	2
Containment Quench Spray		
Manual**	4	2
Containment pressure (Hi-3) high high	4	2
Containment Recirculation Spray		
Manual**	4	2
RWST level low	3	2
Coincident with Containment Pressure high high	4	2

NOTES:

*Permissible bypass if reactor coolant pressure is less than 2,000 psig.

**Manual actuation of containment spray is accomplished by actuating either of two sets (two switches per set). Both switches in a set must be actuated to obtain a manually initiated containment depressurization signal per train.

TABLE 7.3-2

INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

Functional Unit	No. of Channels	Channels Needed to Trip
Containment Isolation		
1. Automatic safety injection (Phase A)		
a. Containment pressure (Hi-1)	3	2
b. Low compensated steam line pressure (lead-lag compensated)	3/steam line	2/steam line any steam line
c. Pressurizer low pressure*	3	2
2. Containment pressure (Phase B)		
a. Hi-3	4	2
3. Manual		
a. Phase A	2	1
b. Phase B**	4	2
Steam Line Isolation		
1. High steam pressure rate	3/steam line	2/steam line any steam line
2. Containment pressure (Hi-2)	3	2
3. Low steam line pressure	3/steam line	2/steam line any steam line
4. Manual	1 loop***	1/loop
Feedwater Line Isolation		
1. Safety Injection		
a. Manual	2	1
b. Containment pressure (Hi-1)	3	2
c. Low compensated steam line pressure (lead-lag compensated)	3/steam line	2/steam line any steam line
d. Pressurizer low pressure*	3	2

TABLE 7.3-2 (Cont)

NOTES:

*Permissible bypass if reactor coolant pressure is less than 2,000 psig.

**Manual actuation of containment spray is accomplished by actuating either of two sets (two switches per set). Both switches in a set must be actuated to obtain a manually-initiated containment depressurization signal per train.

***Additionally there will be two sets of control devices (two momentary controls per set) on the main control board. Operating either set will actuate all three main steam line stop and bypass valves at the system level.

TABLE 7.3-3

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Input	Function Performed
P-4[1]	Reactor tripped	Presence of P-4 signal actuates turbine trip
		Presence of P-4 signal allows manual reset/block of the automatic reactuation of safety injection
		Absence of P-4 signal defeats the manual reset/block preventing automatic reactuation of safety injection
		Presence of P-4 signal closes main feedwater valves on T_{avg} below setpoint. Presence of P-4 signal prevents opening of main feedwater valves which were closed by safety injection high-high steam generator water level
P-11	2/3 pressurizer pressure below setpoint (Presence signal permits functions shown. Absence of signal defeats functions shown)	Allows manual block of safety injection on low pressurizer pressure signal
		Allows manual block of safety injection actuation on low compensated steamline pressure signal
		Permits steamline isolation via high steam pressure rate if low pressure signal manually blocked

TABLE 7.3-3 (Cont)

Designation	Input	Function Performed
P-12	2/3 T_{avg} below setpoint (Presence of P-12 signal performed or permits functions shown. Absence of signal defeats function shown)	Blocks steam dump except for cooldown condenser dump valves Allows manual bypass of steam water dump block for the cooldown valves only

(1) See Table 7.7-1 for control system functions.

TABLE 7.3-4

FMEAs PERFORMED ON
INSTRUMENTATION & CONTROLS AND ELECTRICAL PORTIONS
ENGINEERED SAFETY FEATURES & AUXILIARY SUPPORTING SYSTEMS

FMEA Title	FMEA Dwg No.
Steam Systems	
Main steamline isolation system	15-2
Steam generator blowdown system	5-15
Water Systems	
Station service water system	17-1
Primary component cooling water system	12-7
Condensate and feedwater system	5-4
Auxiliary feedwater system	5-13
Engineered Safety Features Systems	
Residual heat removal system	25-7
High head safety injection system	26-1
Low head safety injection system	26-2
Recirculation spray system	27-1
Quench spray system	27-9
RCS - pump hot/cold leg, bypass isolation	25-4
RCS - pressurizer control	25-6
RCS - reactor coolant letdown	25-13
Electrical Systems	
Class 1E ac power system	22-5
Class 1E dc power system	22-10
Vital bus uninterruptible power system	22-12
Engineered safety features load sequencing	22-6.1
480 V ac emergency power supply	22-8
Containment isolation signal initiation system	27-12
Emergency Diesel Generator Systems	
Emergency diesel generator fuel oil storage and transfer system	8-9
Emergency diesel generator starting system	22-6
Emergency diesel generator spurious trip	22-6.5

TABLE 7.3-4 (Cont)

FMEA Title	FMEA Dwg No.
Ventilation Systems	
Control room ventilation system	21-1
Control building ventilation system	21-2
Main steam and feedwater valve area ventilation system	21-6
Safeguards area ventilation system	21-7
Cable vault and rod control area ventilation system	21-8
Auxiliary building ventilation system	21-21
Primary intake structure ventilation system	21-23
Emergency diesel generator building ventilation system	21-34
Emergency switchgear room ventilation system	21-55
Battery room ventilation system	21-56
Service Systems	
Reactor plant and process sampling system	14-15
Supplementary leak collection and release system	21-18
Containment purge air system	21-19
Containment vacuum leakage monitoring system	27-10
Combustible gas control system	27-13
Spent fuel pool cooling and cleanup system	29-8

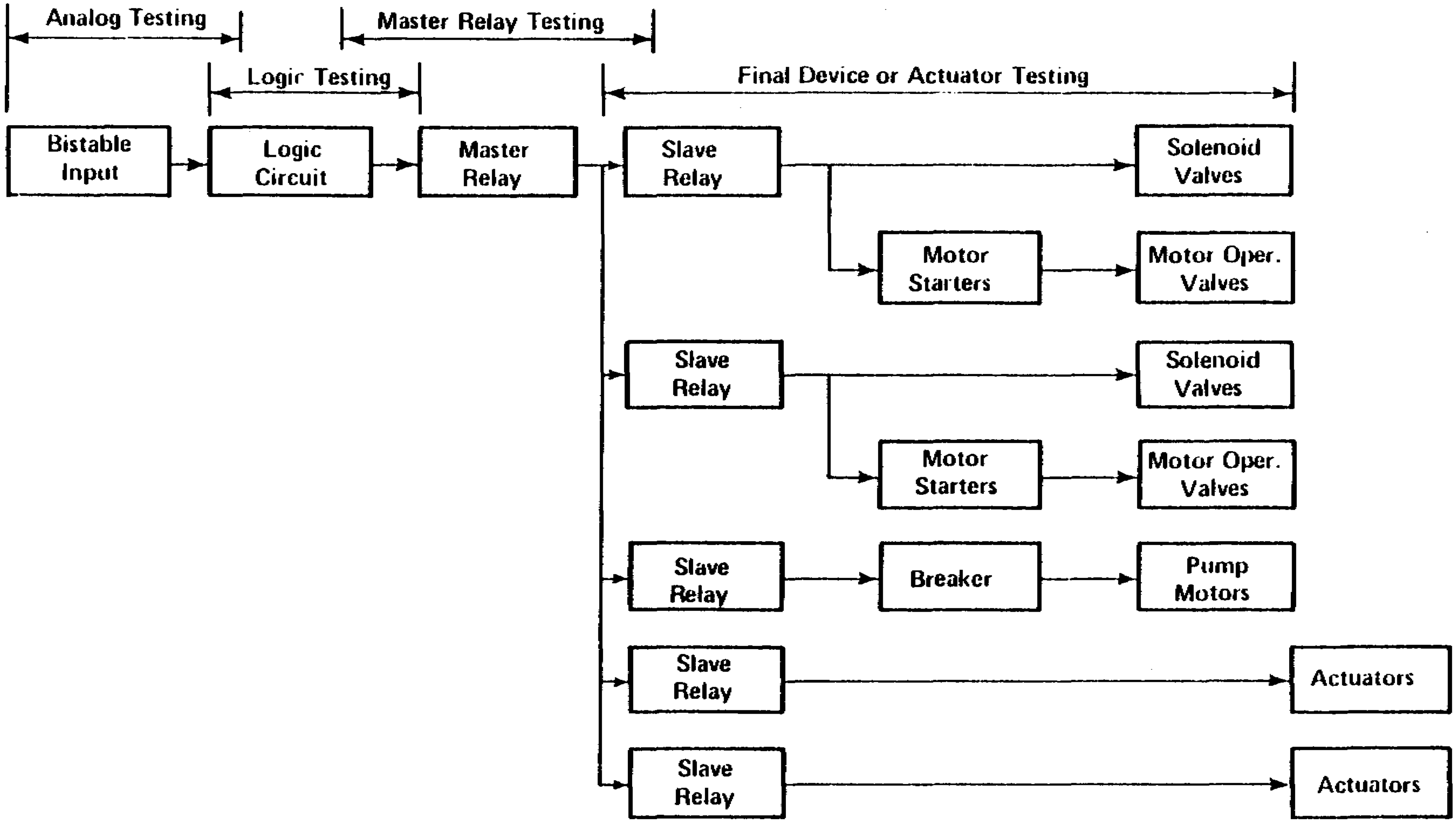
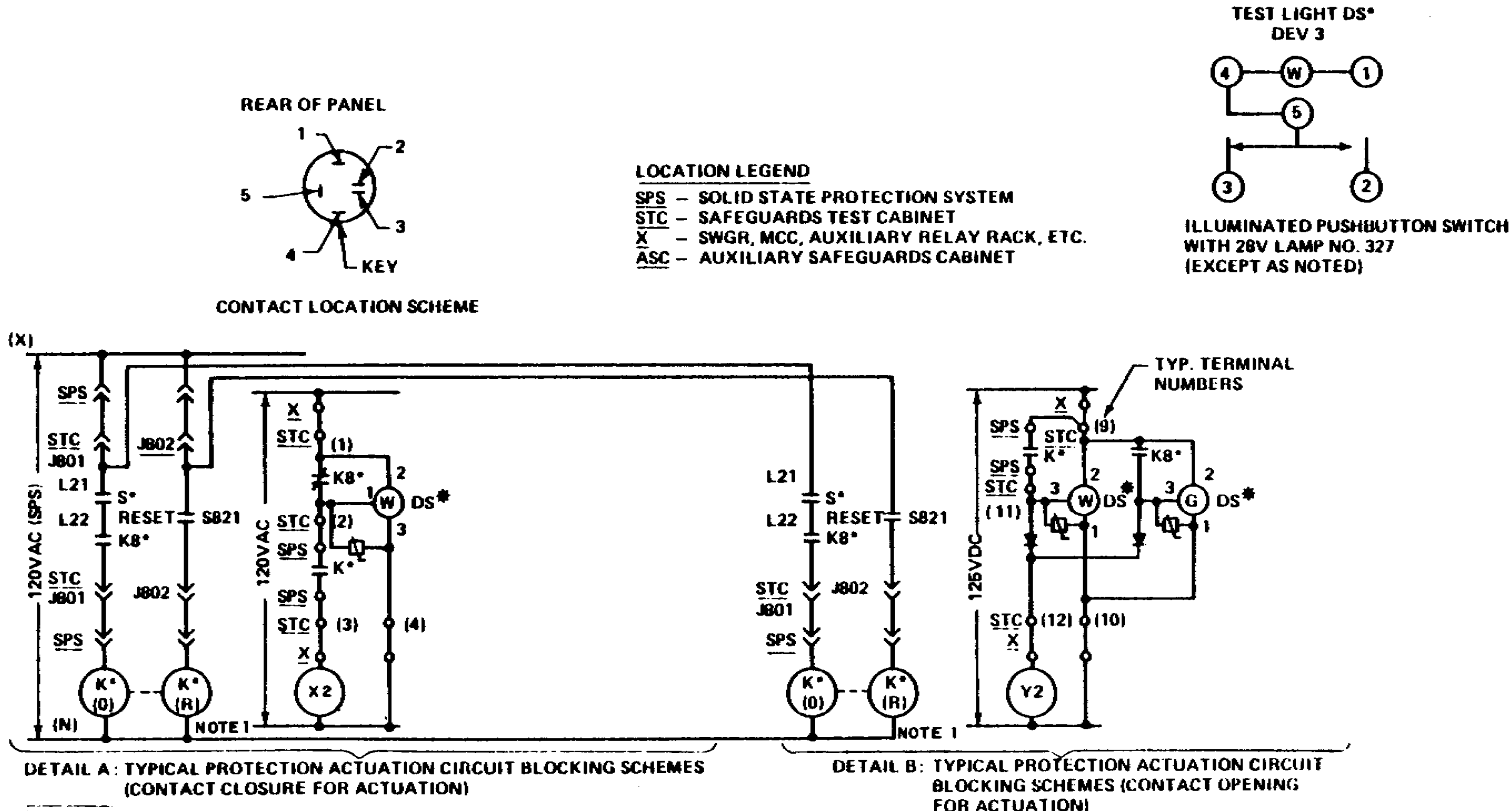


FIGURE 7.3-3
TYPICAL ESF TEST CIRCUITS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



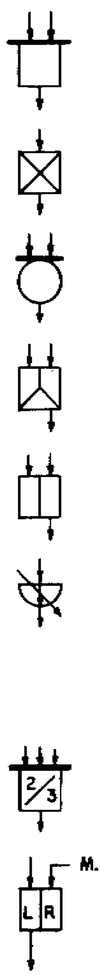
*DETAILS A AND B OF THIS FIGURE ARE NOT TO BE CONFUSED WITH ALPHA DESIGNATION OF LOGIC TRAINS A AND B

NOTES:

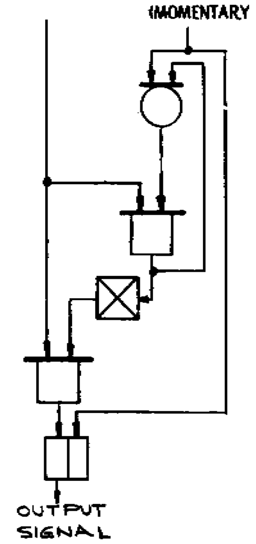
1. SOLID STATE PROTECTION SYSTEM OUTPUT (SLAVE RELAY)
2. ALL DIODES ARE 1N5408
3. ALL VARISTORS ARE GE V130LA20A UNLESS OTHERWISE SPECIFIED. POLARITY NEED NOT TO BE OBSERVED.

FIGURE 7.3-4
SIMPLIFIED ELEMENTARY ENGINEERED SAFEGUARDS TEST CABINET
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

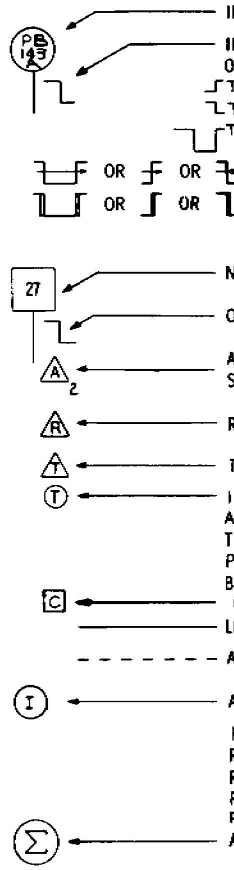
LOGIC SYMBOLS



SYMBOL	LOGIC FUNCTION	
	AND	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN EVERY INPUT EXISTS.
	NOT	A DEVICE WHICH PRODUCES AN OUTPUT ONLY WHEN THE INPUT DOES NOT EXIST.
	OR	A DEVICE WHICH PRODUCES AN OUTPUT WHEN ONE INPUT (OR MORE) EXISTS.
	OFF RETURN MEMORY	A DEVICE WHICH RETAINS THE CONDITION OF OUTPUT CORRESPONDING TO THE LAST ENERGIZED INPUT, EXCEPT UPON INTERRUPTION OF POWER IT RETURNS TO THE OFF CONDITION.
	RETENTIVE MEMORY	A DEVICE WHICH RETAINS THE CONDITION OF OUTPUT CORRESPONDING TO THE LAST ENERGIZED INPUT (ALSO UPON INTERRUPTION OF POWER).
	ADJUSTABLE TIME DELAY ENERGIZING	A DEVICE WHICH PRODUCES AN OUTPUT FOLLOWING DEFINITE INTENTIONAL TIME DELAY AFTER RECEIVING AN INPUT.
2/3	COINCIDENCE (2 OUT OF 3 SHOWN)	A DEVICE WHICH PRODUCES AN OUTPUT WHEN THE PRESCRIBED NUMBER OF INPUTS EXIST (EXAMPLE 2 INPUTS MUST EXIST FOR AN OUTPUT).
M.R. L R	RETENTIVE MEMORY WITH MANUAL RESET	A DEVICE HAVING THE LOGICAL FUNCTION AS INDICATED BY THE DIAGRAM BELOW



ADDITIONAL SYMBOLS



INSTRUMENT CHANNEL BISTABLE

INDICATES THAT THE DEVICE OR INSTRUMENT CHANNEL HAS A BISTABLE LOGIC 1 OUTPUT WHEN:

- THE PARAMETER MEASURED IS GREATER THAN A PRESET VALUE
- THE PARAMETER MEASURED IS LESS THAN A PRESET VALUE
- THE PARAMETER MEASURED DEVIATES FROM A PRESET VALUE BY MORE THAN A PRESET AMOUNT.

OR OR SAME AS ABOVE EXCEPT WITH AN AUTOMATICALLY SET VARIABLE VALUE

OR OR SAME AS ABOVE EXCEPT WITH REQUIRED HYSTERESIS BETWEEN TURN ON AND TURN OFF.

NON-INSTRUMENT BISTABLE

OUTPUT INDICATOR SAME AS EXPLAINED ABOVE

ALARM ANNUNCIATOR (ALARMS ON THE SAME SHEET WITH THE SAME SUBSCRIPT SHARE A COMMON ANNUNCIATOR WINDOW

REACTOR TRIP "FIRST OUT" ANNUNCIATOR

TURBINE TRIP "FIRST OUT" ANNUNCIATOR

INDICATOR LAMP
A ACTUATION STATUS LIGHTS
T TRIP STATUS LIGHTS
P PERMISSIVE STATUS LIGHTS
B - BYPASS STATUS LIGHTS

COMPUTER INPUT

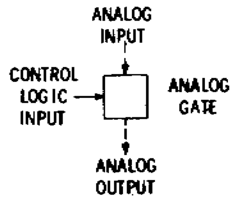
LOGIC INFORMATION TRANSMISSION

- - - - - - - ANALOG INFORMATION TRANSMISSION

ANALOG DISPLAY

I	ANALOG INDICATOR
R	RECORDER
R2	RECORDER 2 PEN
R3	RECORDER 3 PEN
R8	RECORDER 8 POINT

ANALOG SUMMER



A DEVICE WHICH PERMITS AN ANALOG SIGNAL TO PASS IN AN ISOLATED CIRCUIT IF THE CONTROL LOGIC INPUT EXISTS.

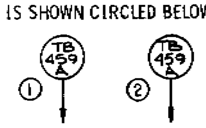
NOTES:

1. IN ALL LOGIC CIRCUITS, THE INDICATED ACTUATION OF A SYSTEM OR DEVICE OCCURS WHEN A LOGIC 1 SIGNAL IS PRESENT. EXCEPT WHERE INDICATED OTHERWISE, ALL BISTABLES ARE "DE-ENERGIZE TO ACTUATE" SUCH THAT A LOGIC 1 SIGNAL IS DEFINED TO BE PRESENT WHEN THE BISTABLE OUTPUT VOLTAGE IS OFF.
2. EXCEPT WHERE INDICATED OTHERWISE, THE FOLLOWING IS TRUE: ALL LOGIC CIRCUITS ARE REDUNDANT. ALL INSTRUMENT CHANNELS, BISTABLES, ANNUNCIATORS, COMPUTER INPUTS, AND INDICATOR LAMPS ARE NOT REDUNDANT. MANUAL CONTROLS DO NOT HAVE REDUNDANT ACTUATORS, BUT DO HAVE REDUNDANT CONTACTS WHERE LOGIC IS REDUNDANT. ALL INDICATOR LAMPS, ANNUNCIATORS, AND COMPUTER INPUTS ARE CONNECTED TO BOTH TRAINS (WHERE LOGIC IS REDUNDANT) SO THAT A SIGNAL IN EITHER TRAIN WILL ACTUATE.
3. FOR UNIT 2 TAG NUMBERS ADD A PREFIX '2'.
   EXAMPLE: 2PB-143A.
4. WHENEVER A PROCESS SIGNAL IS USED FOR CONTROL AND IS DERIVED FROM A PROTECTION CHANNEL, ISOLATION MUST BE PROVIDED.
5. THIS SET OF DRAWINGS ILLUSTRATES THE FUNCTIONAL REQUIREMENTS OF THE REACTOR CONTROL AND PROTECTION SYSTEM, INCLUDING ENGINEERED SAFEGUARDS. THESE DRAWINGS DO NOT REPRESENT ACTUAL HARDWARE IMPLEMENTATION. FOR HARDWARE IMPLEMENTATION, REFER TO THE FOLLOWING LIST:

FUNCTIONAL DIAGRAM	BLOCK OR WIRING DIAGRAM
REACTOR PROTECTION SYSTEM (SHEETS 1 TO 8 AND 16)	DRAWING NUMBERS: 7243D05, 5655D49, 5665D50, 5655D51, 1189E15, 271C821, 1083H85, 7247D75.
REACTOR CONTROL SYSTEM (SHEETS 9 TO 15)	DRAWING NUMBERS: 7243D05, 5655D52, 271C821.

6. FOR DUAL BISTABLES (I.E. BISTABLE WITH COMMON INPUT CIRCUITRY, BUT WITH 2 SETPOINTS, 2 OUTPUTS) THE OUTPUT/SETPOINT NUMBER (AS TAGGED PHYSICALLY ON THE BISTABLE) IS SHOWN CIRCLED BELOW THE BISTABLE SYMBOL.

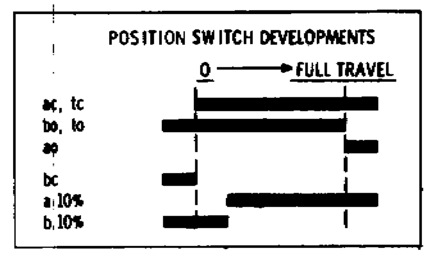
EXAMPLE



DEVICE FUNCTION LETTERS AND NUMBERS

FB	FLOW CHANNEL
LB	LEVEL CHANNEL
NC	NUCLEAR CHANNEL
PB	PRESSURE CHANNEL
RC	RADIATION CHANNEL
SB	SPEED CHANNEL
TB	TEMPERATURE CHANNEL
ZB	POSITION CHANNEL
20	ELECTRIC OPERATED VALVE
27	UNDERVOLTAGE RELAY
33	POSITION SWITCH

SUFFIX LETTER:
ac, ao, bc, bo LIMIT SWITCH
tc, to - TORQUE SWITCH



(VALVE CLOSED) (VALVE OPEN)

52 AC CIRCUIT BREAKER
SUFFIX LETTER:
a AUXILIARY CONTACT - OPEN WHEN MAIN CONTACTS ARE OPEN
b AUXILIARY CONTACT - CLOSED WHEN MAIN CONTACTS ARE OPEN
H-IN CELL SWITCH - CLOSE WHEN BREAKER IS IN THE CONNECTED POSITION

63	PRESSURE SWITCH
71	LEVEL SWITCH
80	FLOW SWITCH
81	UNDERFREQUENCY RELAY

INDEX

TITLE	SHEET NO.	SUBS									
INDEX AND SYMBOLS	1	1	2	3	4	5	6	7	8		
REACTOR TRIP SIGNALS	2	1	2	3	3	3	4	4	4		
NUCLEAR INSTR. AND MANUAL TRIP SIGNALS	3	1	2	2	2	2	2	2	2		
NUCLEAR INSTR. PERMISSIVES AND BLOCKS	4	1	1	2	3	3	3	3	3		
PRIMARY COOLANT SYSTEM TRIP SIGNALS	5	1	2	2	3	4	4	5	5		
PRESSURIZER TRIP SIGNALS	6	1	2	3	4	5	5	6	6		
STEAM GENERATOR TRIP SIGNALS	7	1	2	3	4	4	4	4	4		
SAFEGUARDS ACTUATION SIGNALS	8	1	2	3	4	5	6	7	8		
ROD CONTROLS & ROD BLOCKS	9	1	2	2	2	2	2	2	2		
STEAM DUMP CONTROL	10	1	2	3	4	4	4	4	4		
PRESSURIZER PRESSURE & LEVEL CONTROL	11	1	2	3	3	4	4	4	4		
PRESSURIZER HEATER CONTROL	12	1	1	2	2	2	2	2	2		
FEEDWATER CONTROL & ISOLATION	13	1	2	3	3	3	3	4	4		
AUXILIARY FEEDWATER PUMPS STARTUP	14	1	2	3	3	3	3	3	3		
TURBINE TRIPS RUNBACKS & OTHER SIGNALS (* REQUIREMENTS)	15	1	2	3	4	4	4	5	5		
LOOP STOP VALVE INTERLOCKS	16	1	2	2	2	2	2	2	2		
PRESSURIZER PRESSURE RELIEF SYSTEM (TRAIN A)	17					1	2	2	2		
PRESSURIZER PRESSURE RELIEF SYSTEM (TRAIN B)	18					1	2	2	2		

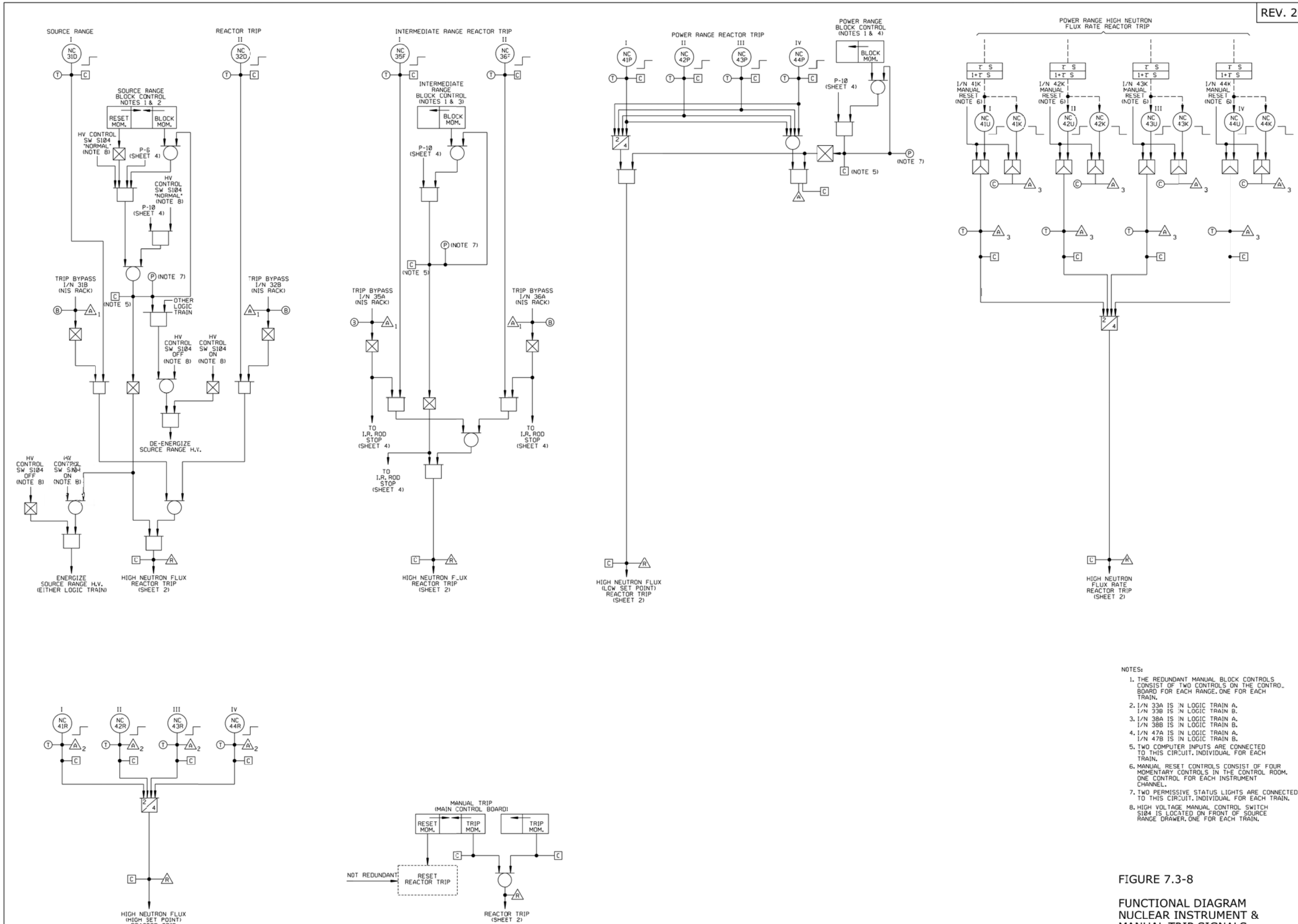
FIGURE 7.3-6
FUNCTIONAL DIAGRAM INDEX AND SYMBOLS
BEAVER VALLEY POWER STATION-UNIT-2

UPDATED FINAL SAFETY ANALYSIS REPORT

NOTES:

1. TRIPPING THE REACTOR TRIP BREAKERS 52/RTA AND 52/RTB REDUNDANTLY DE-ENERGIZES THE ROD DRIVES. ALL FULL LENGTH CONTROL RODS AND SHUTDOWN RODSARE THEREBY RELEASED FOR GRAVITY INSERTION INTO THE REACTOR CORE.
2. NORMAL REACTOR OPERATION IS TO BE WITH REACTOR TRIP BREAKERS 52/RTA AND 52/RTB IN SERVICE AND BY-PASS BREAKERS 52/BYA AND 52/BYB WITHDRAWN. DURING TEST ONE BY-PASS BREAKER IS TO BE PUT IN SERVICE AND THEN THE RESPECTIVE REACTOR TRIP BREAKER IS OPERATED USING A SIMULATED REACTOR TRIP SIGNAL IN THE TRAIN UNDER TEST. THE REACTOR WILL NOT BE TRIPPED BY THE SIMULATED SIGNAL SINCE THE BY-PASS BREAKER IS CONTROLLED FROM THE OTHER TRAIN.
3. THE BY-PASS BREAKER INTERLOCK IS OPERATIVE ONLY WHEN BOTH BY-PASS BREAKERS ARE IN THE OPERATE POSITION.
4. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT BECAUSE BOTH TRAINS ARE SHOWN.

FIGURE 7.3-7
FUNCTIONAL DIAGRAM
REACTOR TRIP SIGNALS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

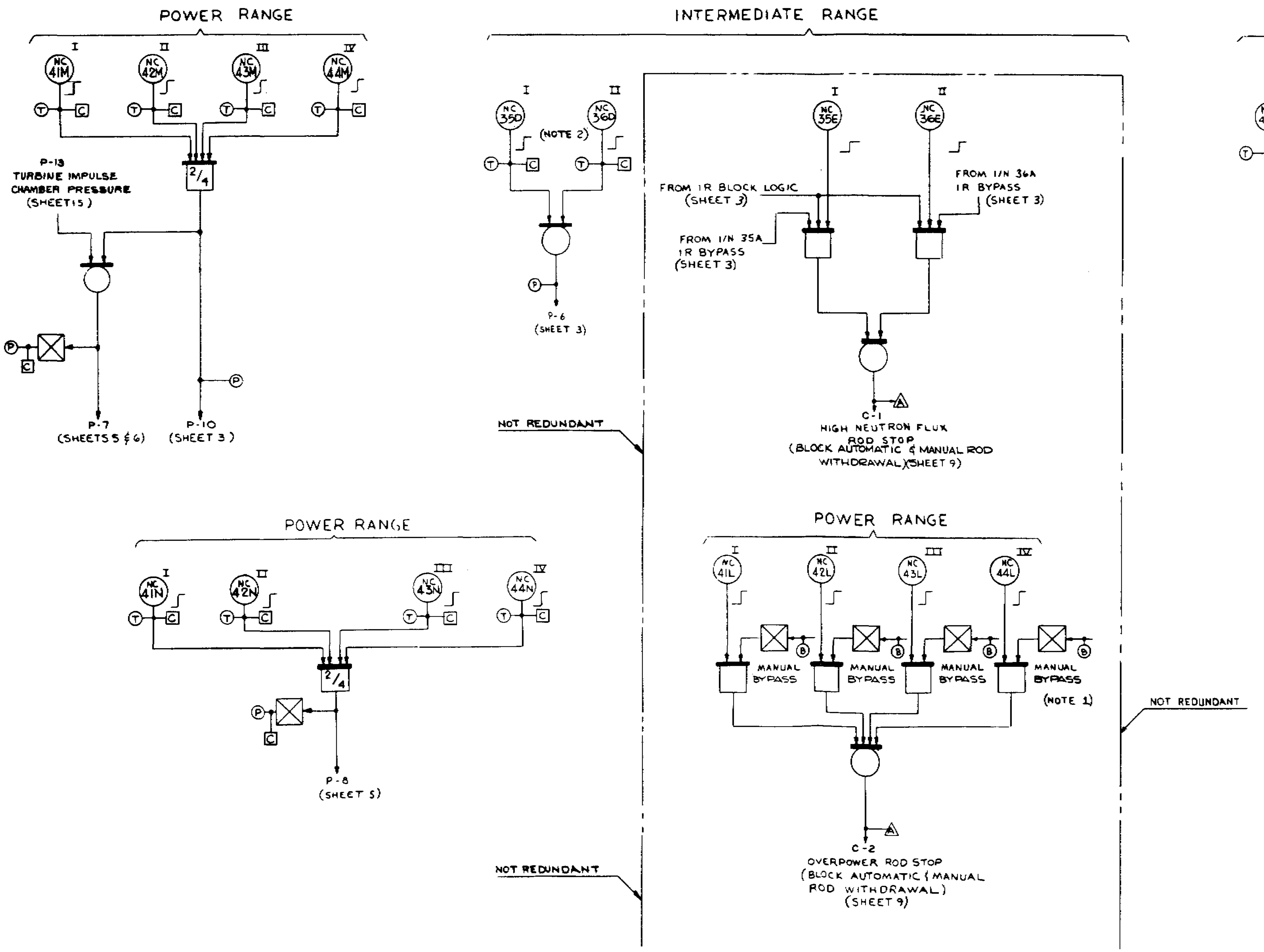
1. THE REDUNDANT MANUAL BLOCK CONTROLS CONSIST OF TWO CONTROLS ON THE CONTROL BOARD FOR EACH RANGE. ONE FOR EACH TRAIN.
2. I/N 33A IS IN LOGIC TRAIN A. I/N 33B IS IN LOGIC TRAIN B.
3. I/N 38A IS IN LOGIC TRAIN A. I/N 38B IS IN LOGIC TRAIN B.
4. I/N 47A IS IN LOGIC TRAIN A. I/N 47B IS IN LOGIC TRAIN B.
5. TWO COMPUTER INPUTS ARE CONNECTED TO THIS CIRCUIT. INDIVIDUAL FOR EACH TRAIN.
6. MANUAL RESET CONTROLS CONSIST OF FOUR MOMENTARY CONTROLS IN THE CONTROL ROOM. ONE CONTROL FOR EACH INSTRUMENT CHANNEL.
7. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT. INDIVIDUAL FOR EACH TRAIN.
8. HIGH VOLTAGE MANUAL CONTROL SWITCH S104 IS LOCATED ON FRONT OF SOURCE RANGE DRAWER. ONE FOR EACH TRAIN.

FIGURE 7.3-8

FUNCTIONAL DIAGRAM
NUCLEAR INSTRUMENT &
MANUAL TRIP SIGNALS

(BV2 2001.409-001-019, REV. N)
BEAVER VALLEY POWER STATION UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

K:\u2\UFSAR\FIGURES 7.1 THRU\FIG 7.3-8.dgn



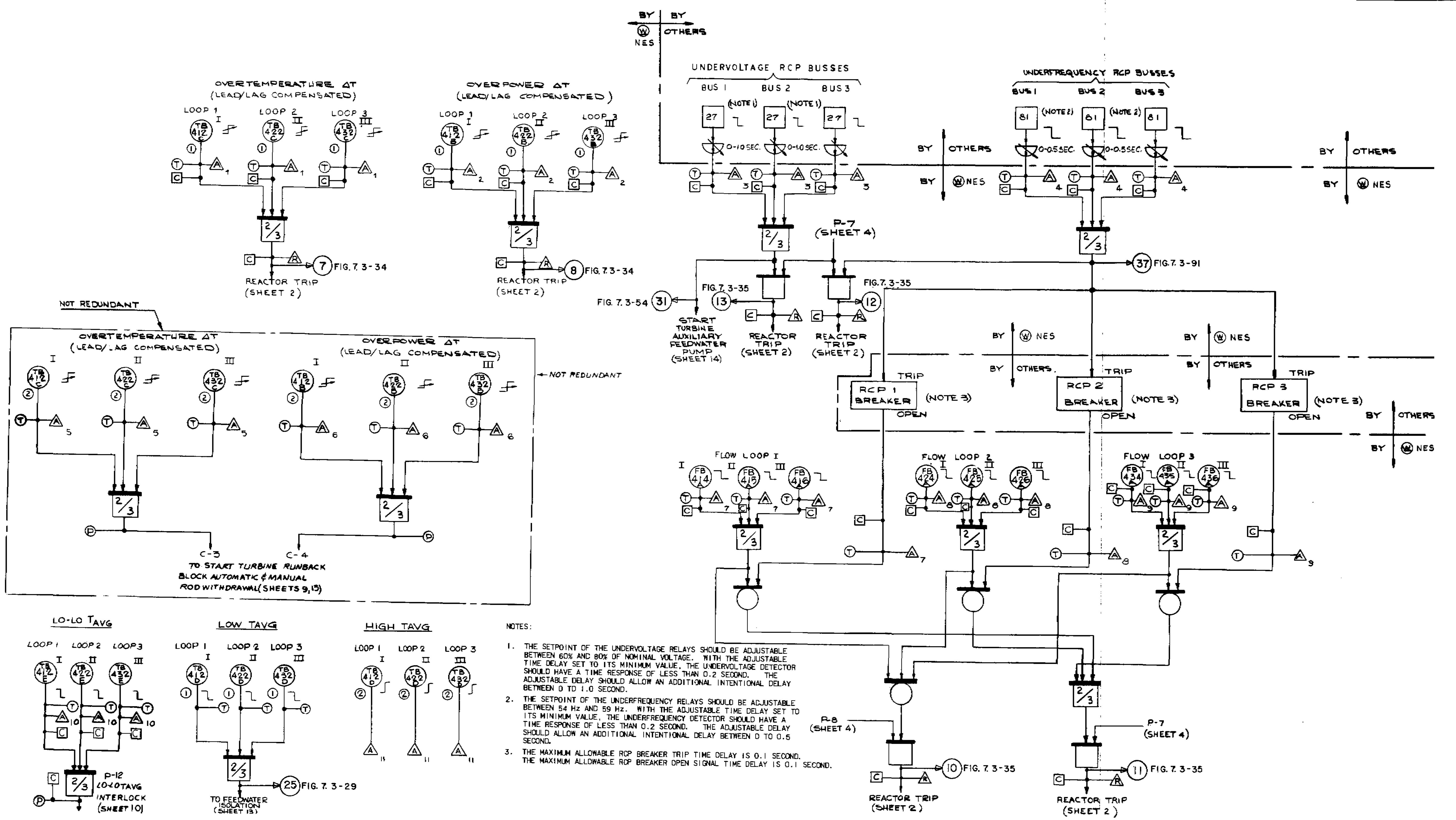
NOTES:

1. THE BY-PASS SIGNALS ARE MADE UP BY MEANS OF TWO THREE-POSITION SWITCHES ON A NIS RACK. SWITCH I/N 49A BYPASSES EITHER NC-41L OR NC-43L. SWITCH I/N 49B BYPASSES EITHER NC-42L OR NC-44L.

2. THE TWO P-6 BISTABLES NO. NC-350 AND NC-36D ARE "ENERGIZED TO ACTUATE" SUCH THAT A LOGIC I SIGNAL IS DEFINED TO BE PRESENT WHEN THE BISTABLE OUTPUT VOLTAGE IS ON.

FIGURE 7.3-9
FUNCTIONAL DIAGRAM NUCLEAR INSTRUMENT PERMISSIVES & BLOCKS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 9 (96)

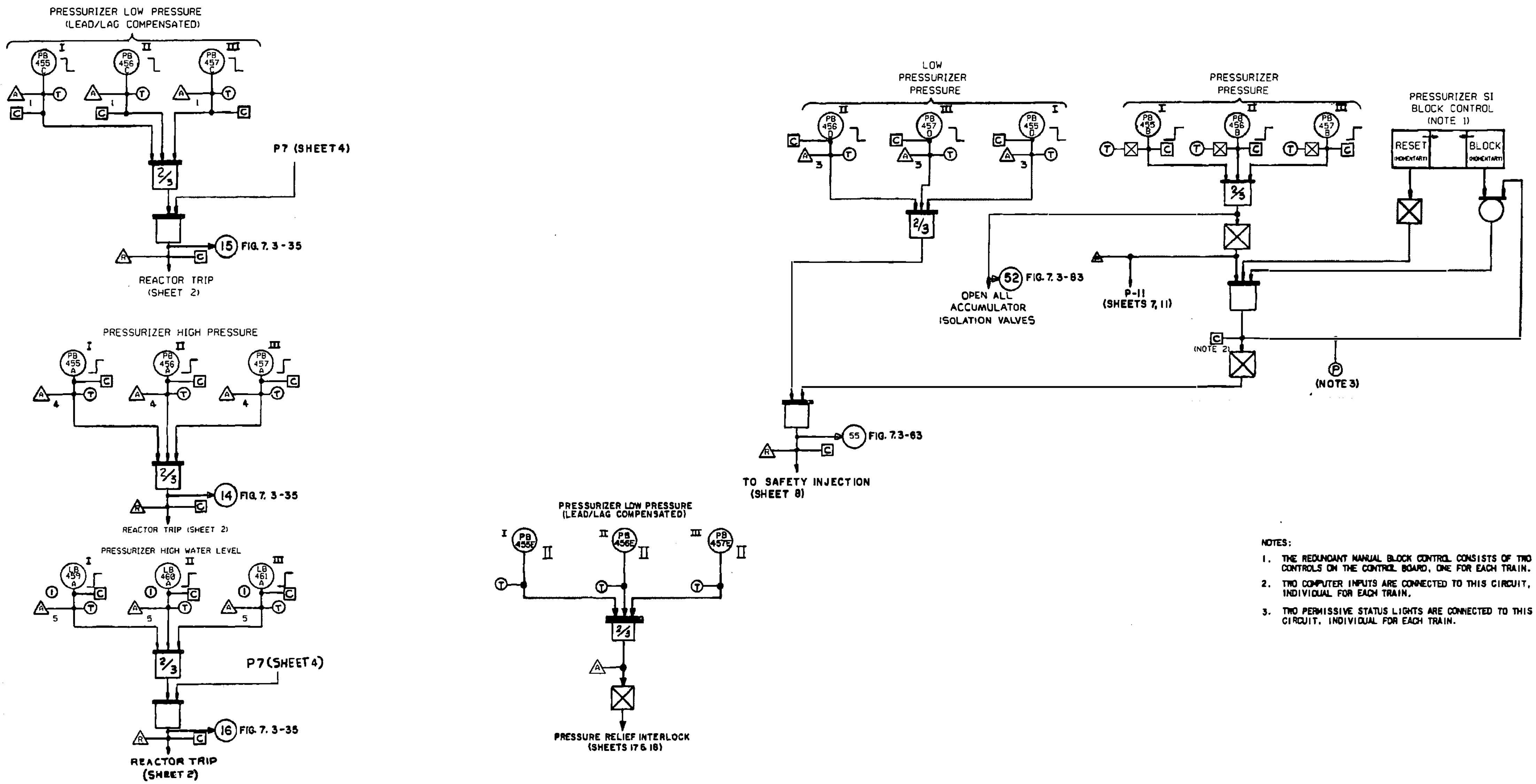


NOTES:

1. THE SETPOINT OF THE UNDERVOLTAGE RELAYS SHOULD BE ADJUSTABLE BETWEEN 60% AND 80% OF NOMINAL VOLTAGE. WITH THE ADJUSTABLE TIME DELAY SET TO ITS MINIMUM VALUE, THE UNDERVOLTAGE DETECTOR SHOULD HAVE A TIME RESPONSE OF LESS THAN 0.2 SECOND. THE ADJUSTABLE DELAY SHOULD ALLOW AN ADDITIONAL INTENTIONAL DELAY BETWEEN 0 TO 1.0 SECOND.
2. THE SETPOINT OF THE UNDERFREQUENCY RELAYS SHOULD BE ADJUSTABLE BETWEEN 54 Hz AND 59 Hz. WITH THE ADJUSTABLE TIME DELAY SET TO ITS MINIMUM VALUE, THE UNDERFREQUENCY DETECTOR SHOULD HAVE A TIME RESPONSE OF LESS THAN 0.2 SECOND. THE ADJUSTABLE DELAY SHOULD ALLOW AN ADDITIONAL INTENTIONAL DELAY BETWEEN 0 TO 0.5 SECOND.
3. THE MAXIMUM ALLOWABLE RCP BREAKER TRIP TIME DELAY IS 0.1 SECOND. THE MAXIMUM ALLOWABLE RCP BREAKER OPEN SIGNAL TIME DELAY IS 0.1 SECOND.

FIGURE 7.3-10
FUNCTIONAL DIAGRAM PRIMARY COOLANT SYSTEM TRIP SIGNALS
BEAVER VALLEY POWER STATION-UNIT 2

UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. THE REDUNDANT MANUAL BLOCK CONTROL CONSISTS OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
2. TWO COMPUTER INPUTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.
3. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT, INDIVIDUAL FOR EACH TRAIN.

THIS FIGURE SUPERSEDES FIGURE OF SAME NUMBER REV.3

FIGURE 7.3-11

FUNCTIONAL DIAGRAMS
PRESSURIZER TRIP SIGNALS

(2001.409-001-022, REV K)

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

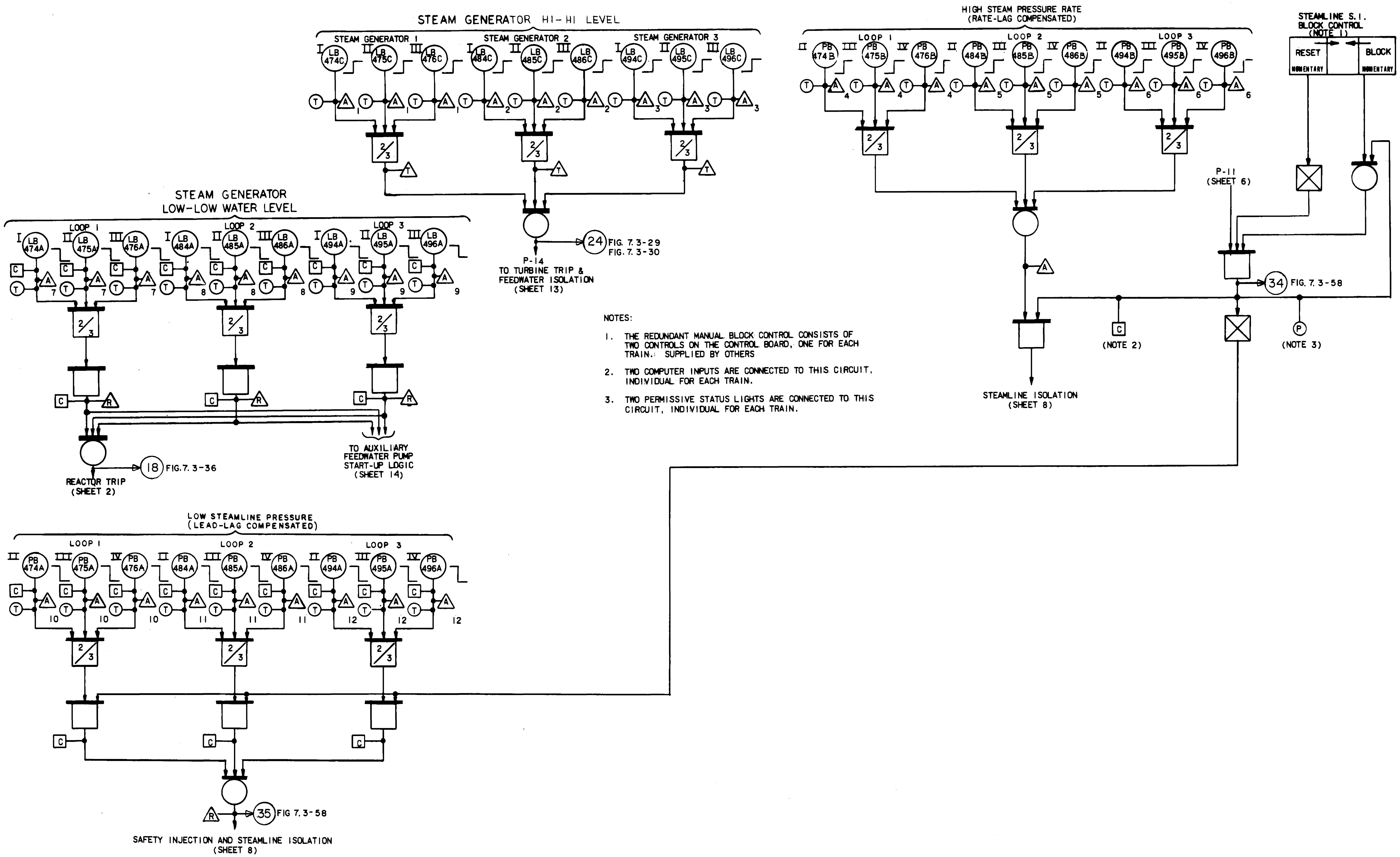
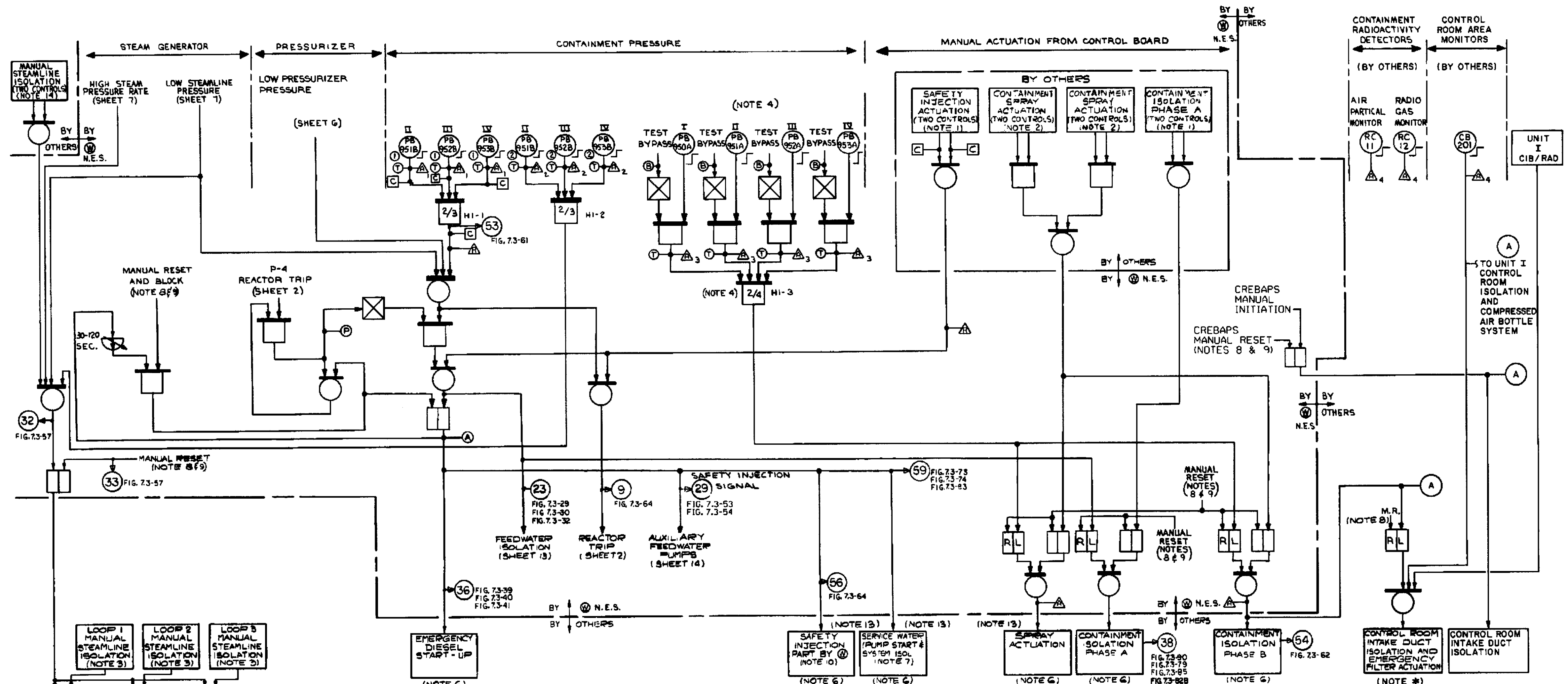
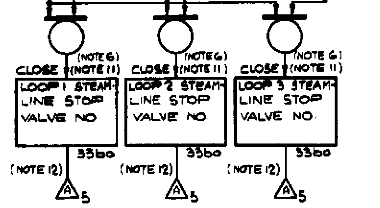


FIGURE 7.3-12
FUNCTIONAL DIAGRAM
STEAM GENERATOR TRIP SIGNALS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



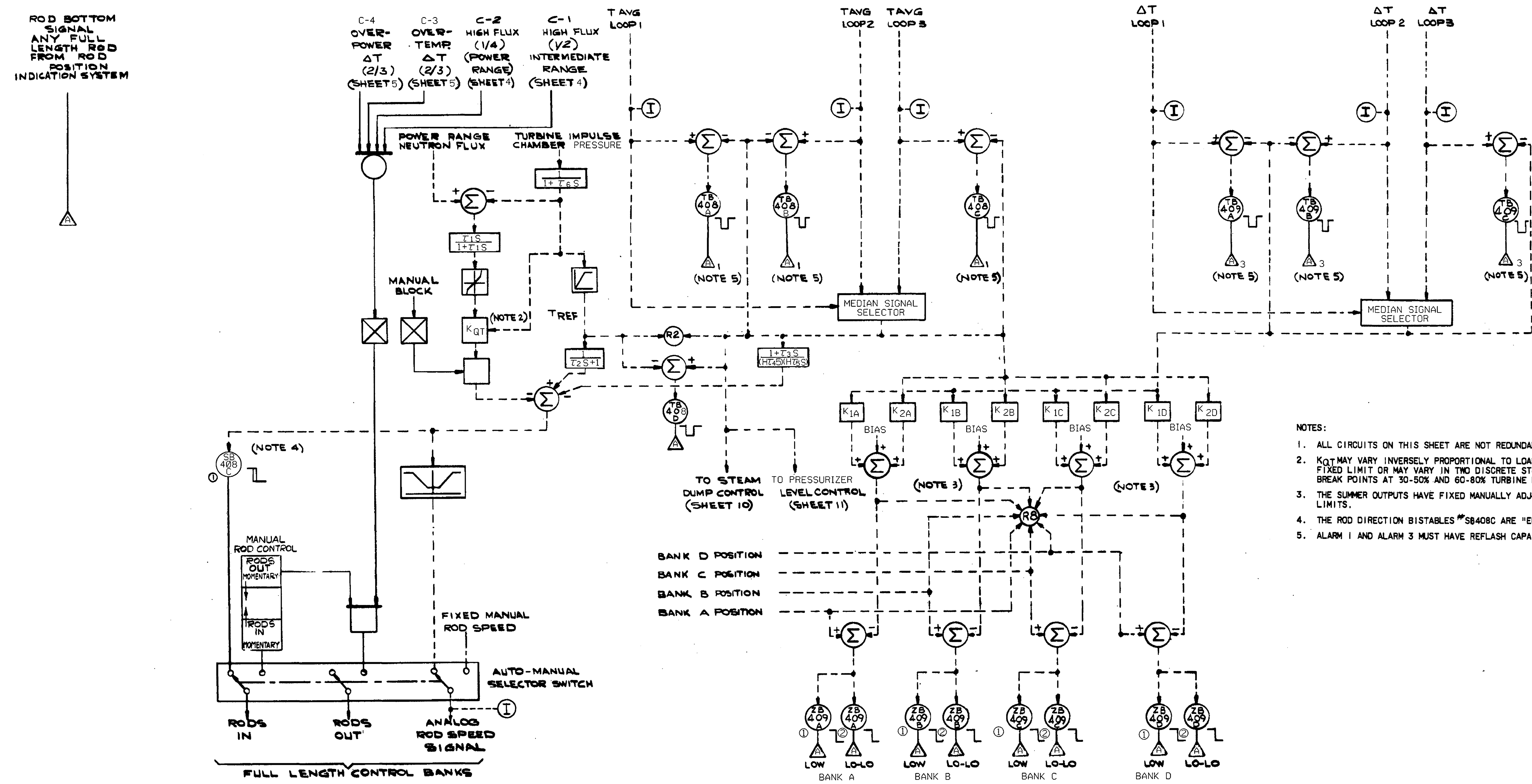


NOTES:

1. TWO MOMENTARY CONTROLS ON THE CONTROL BOARD. OPERATING EITHER CONTROL WILL ACTUATE.
2. THE MANUAL SPRAY ACTUATION CONSISTS OF FOUR MOMENTARY CONTROLS, ACTUATION WILL OCCUR ONLY IF TWO ASSOCIATED CONTROLS ARE OPERATED SIMULTANEOUSLY.
3. ONE MOMENTARY CONTROL PER LOOP ON THE CONTROL BOARD.
4. CONTAINMENT PRESSURE BISTABLES FOR SPRAY ACTUATION ARE ENERGIZE-TO-ACTUATE (OTHER BISTABLES ARE DE-ENERGIZE TO ACTUATE).
6. COMPONENTS ARE INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
7. SERVICE WATER SYSTEM ISOLATION IS USED ONLY IF REQUIRED.
8. THE REDUNDANT MANUAL RESET CONSISTS OF TWO MOMENTARY CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
9. SUPPLIED BY OTHERS.
10. SAFETY INJECTION SEQUENCE REQUIREMENTS (IF SEQUENCE IS NECESSARY) ARE SPECIFIED BY Ⓦ N.E.S.
11. ALSO CLOSES THE BYPASS VALVE IN PARALLEL WITH THE ASSOCIATED STEAM LINE STOP VALVE.
12. LIGHTS SHOULD BE PROVIDED IN THE CONTROL ROOM FOR EACH STEAMLINE STOP VALVE TO INDICATE WHEN THE VALVE IS FULLY CLOSED OR FULLY OPEN.
13. THE ACTUATION MAY BE DELAYED AND SEQUENCED IF THE EMERGENCY DIESEL POWER CAPABILITY IS LESS THAN THE TOTAL LOAD WITH ALL SYSTEMS STARTING. THE TIME DELAY(S), IF USED, MAY NOT EXCEED THE MAXIMUM STARTING TIME REQUIREMENT(S) FOR EACH SYSTEM.
14. THE REDUNDANT MANUAL ACTUATION FOR SYSTEM LEVEL STEAMLINE ISOLATION CONSISTS OF FOUR MOMENTARY CONTROLS, TWO FOR EACH TRAIN. ACTUATION WILL OCCUR IN A GIVEN TRAIN ONLY IF THE TWO ASSOCIATED CONTROLS ARE OPERATED SIMULTANEOUSLY.

NOTE *EMERGENCY FILTRATION SYSTEM IS DELAYED 60 MINUTES.

FIGURE 7.3-13
FUNCTIONAL DIAGRAM
SAFEGUARD ACTUATION SIGNAL
(2001.409-001-024 REV. L)



NOTES:

1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. K_{QT} MAY VARY INVERSELY PROPORTIONAL TO LOAD WITH A FIXED LIMIT OR MAY VARY IN TWO DISCRETE STEPS WITH BREAK POINTS AT 30-50% AND 60-80% TURBINE LOAD.
3. THE SUMMER OUTPUTS HAVE FIXED MANUALLY ADJUSTABLE UPPER LIMITS.
4. THE ROD DIRECTION BISTABLES #SB408C ARE "ENERGIZE TO ACTUATE".
5. ALARM 1 AND ALARM 3 MUST HAVE REFLASH CAPABILITY.

FIGURE 7.3-14

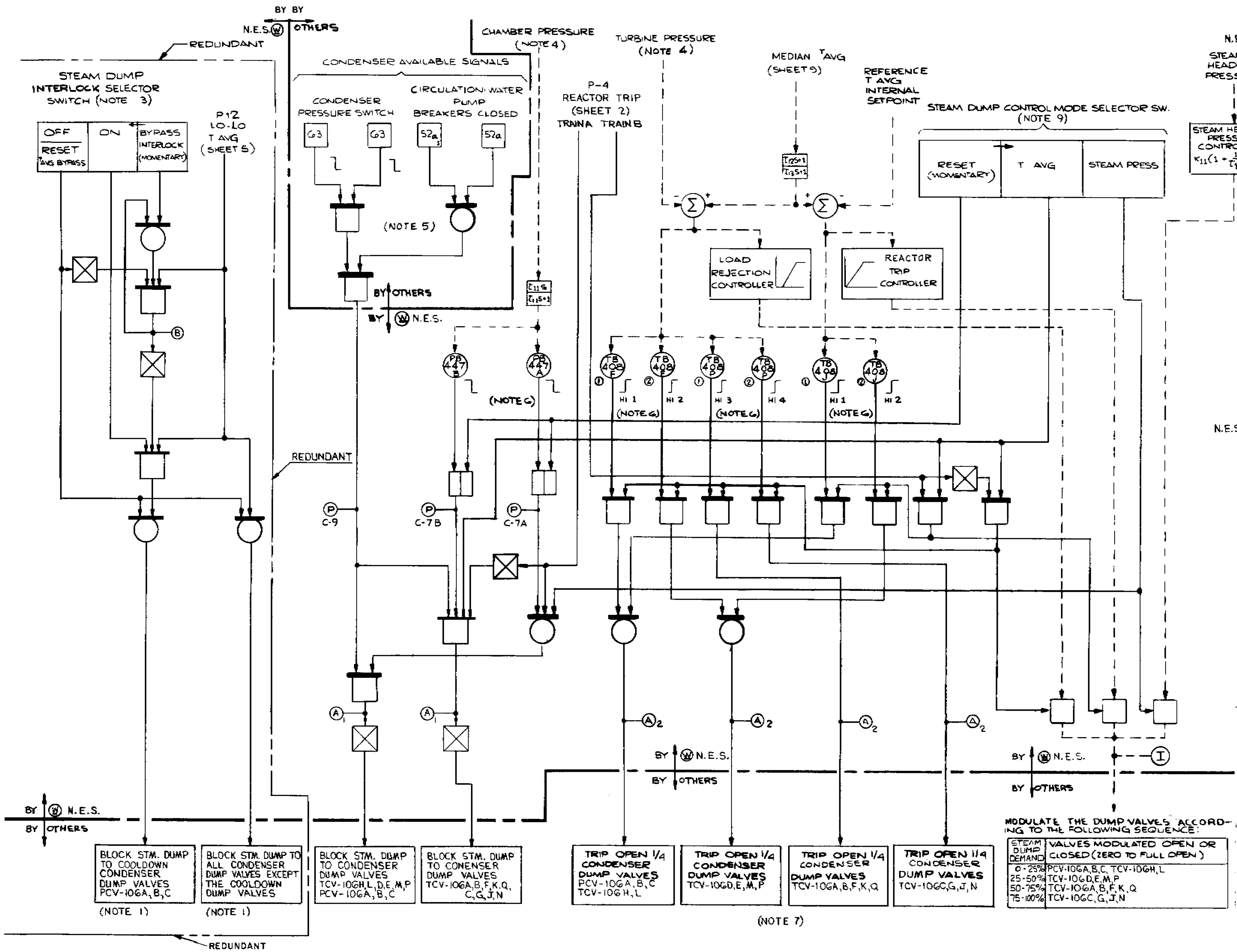
FUNCTIONAL DIAGRAM ROD CONTROLS & ROD BLOCKS

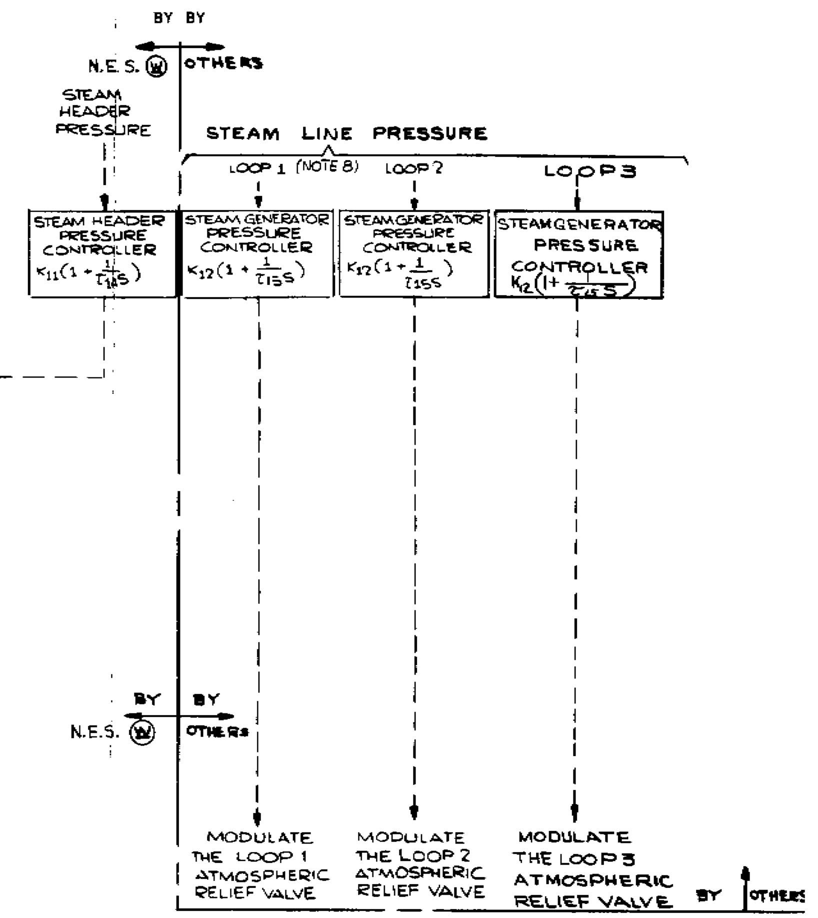
(2001.409-001-025, REV. L)

BEAVER VALLEY POWER STATION-UNIT 2

UPDATED FINAL SAFETY ANALYSIS REPORT

REV 3





NOTES:

1. STEAM DUMP IS BLOCKED BY BLOCKING AIR TO THE DUMP VALVES AND VENTING THE DIAPHRAGM. THE REDUNDANT LOGIC OUTPUT OPERATES 2 SOLENOID VENT VALVES IN SERIES TO REDUNDANTLY INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE NON-REDUNDANT LOGIC OUTPUT OPERATES ONE SOLENOID VENT VALVE TO INTERLOCK THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE SOLENOID VALVES ARE DE-ENERGIZED TO VENT, CAUSING THE MAIN DUMP VALVE TO CLOSE IN FIVE SECONDS. EITHER OF THE TWO REDUNDANT BLOCK SIGNA OR THE NON-REDUNDANT BLOCK SIGNAL WILL BLOCK STEAM DUMP INDEPENDENT OF THE OTHERS.
2. CIRCUITRY ON THIS SHEET IS NOT REDUNDANT EXCEPT WHERE INDICATED REDUNDANT.
3. SELECTOR SWITCH WITH THE FOLLOWING 3 POSITIONS:

   ON - STEAM DUMP IS PERMITTED.

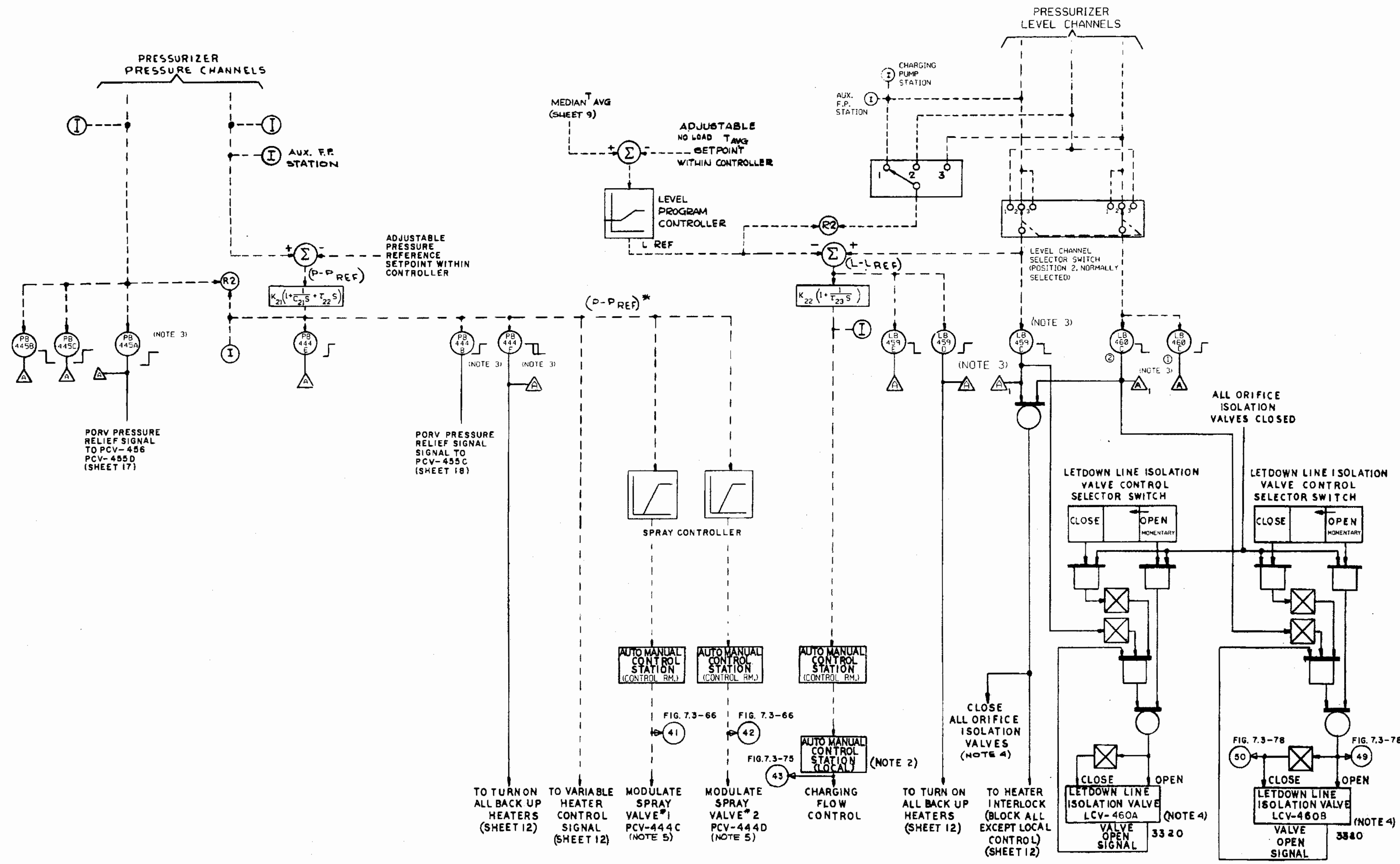
   BYPASS - T AVG INTERLOCK IS BYPASSED FOR LO-LO T AVG. SPRING RETURN TO ON POSITION.

   OFF - STEAM DUMP IS NOT PERMITTED AND RESET T AVG BYPASS.

   THE REDUNDANT INTERLOCK SELECTOR SWITCH CONSISTS OF TWO CONTROLS ON THE CONTROL BOARD, ONE FOR EACH TRAIN.
4. THE TWO ANALOG SIGNAL INPUTS COMING FROM TURBINE PRESSURE MUST COME FROM DIFFERENT PRESSURE TAPS TO MEET THE SINGLE FAILURE CRITERION.
5. THE CONDENSER AVAILABLE SIGNAL LOGIC IS TYPICAL. ACTUAL IMPLEMENTATION MAY BE DIFFERENT.
6. ALL TEMPERATURE BISTABLES ON THIS SHEET AND TURBINE IMPULSE CHAMBER PRESSURE BISTABLES # PB-447A AND PB-447B ARE "ENERGIZE TO ACTUATE".
7. LIGHTS SHOULD BE PROVIDED IN THE CONTROL ROOM FOR EACH DUMP VALVE TO INDICATE WHEN THE VALVE IS FULLY CLOSED OR FULLY OPEN.
8. THE STEAM LINE PRESSURE SIGNAL ORIGIN MUST BE DIFFERENT FROM THAT WHICH IS USED FOR THE STEAMLINE PRESSURE PROTECTION SIGNALS SHOWN ON SHEET 7 TO MEET THE SINGLE FAILURE CRITERION.

FIGURE 7.3-15
FUNCTIONAL DIAGRAM
STEAM DUMP CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 14



THIS FIGURE SUPERSEDES FIGURE OF THE SAME NUMBER REV. 10

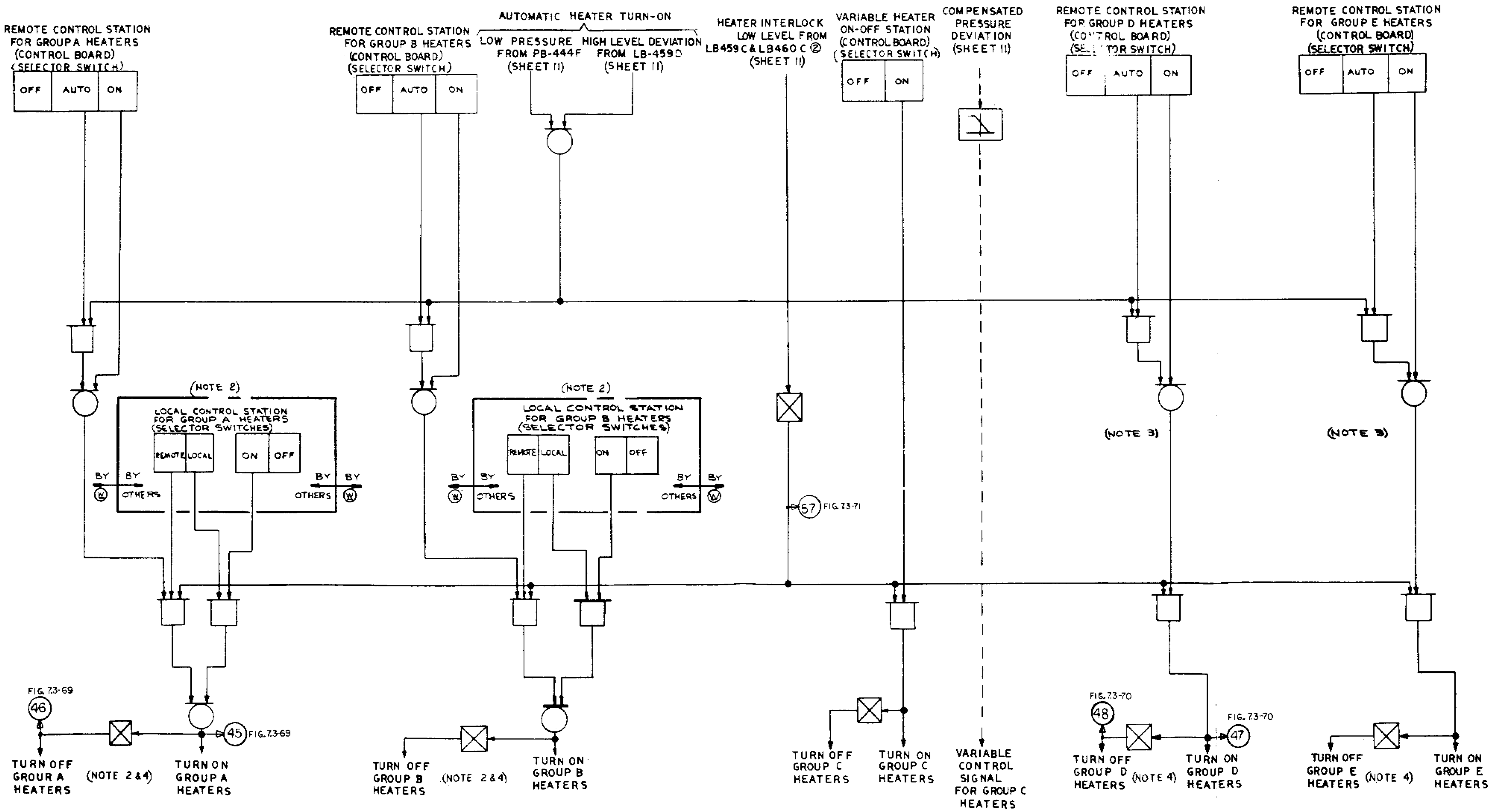
NOTES:

1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. LOCAL CONTROL OVERRIDES ALL OTHER SIGNALS. LOCAL OVERRIDE ACTUATES ALARM IN CONTROL ROOM.
3. PRESSURE BISTABLES NO. PB-444B, PB-444F AND PB-444A AND LEVEL BISTABLES LB-459C, LB-459D AND LB-460C 2 ARE "ENERGIZE TO ACTUATE".
4. OPEN/SHUT INDICATION ON CONTROL ROOM.
5. A LIGHT SHOULD BE PROVIDED IN THE CONTROL ROOM FOR EACH SPRAY VALVE TO INDICATE WHEN THE VALVE IS NOT REALLY CLOSED.

FIGURE 7.3-16

FUNCTIONAL DIAGRAM PRESSURIZER PRESSURE & LEVEL CONTROL

(2001.409-001-027 REV. J)

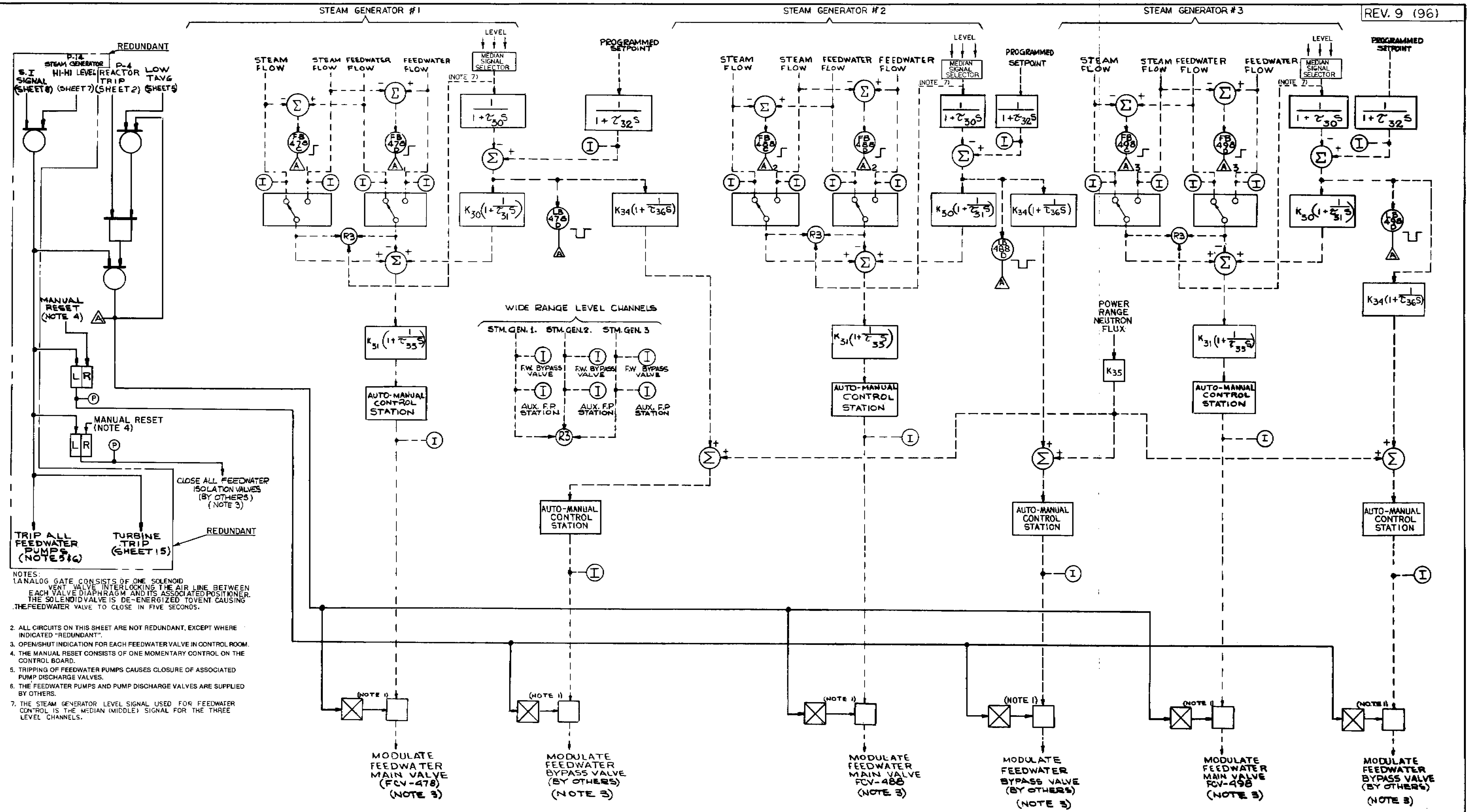


NOTES:

1. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT.
2. GROUP A AND GROUP B HEATERS MUST BE ON SEPARATE VITAL POWER SUPPLIES WITH THE LOCAL CONTROLS SEPARATED SO THAT ANY SINGLE FAILURE DOES NOT DEFEAT BOTH.
3. THE NUMBER OF BACKUP HEATER GROUPS IS TYPICAL. ACTUAL NUMBER OF GROUPS MAY DIFFER DEPENDING ON ELECTRICAL LOADING REQUIREMENTS.
4. BACKUP HEATER STATUS INDICATION IN CONTROL ROOM.

FIGURE 7.3-17
FUNCTIONAL DIAGRAM
PRESSURIZER HEATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 9 (96)



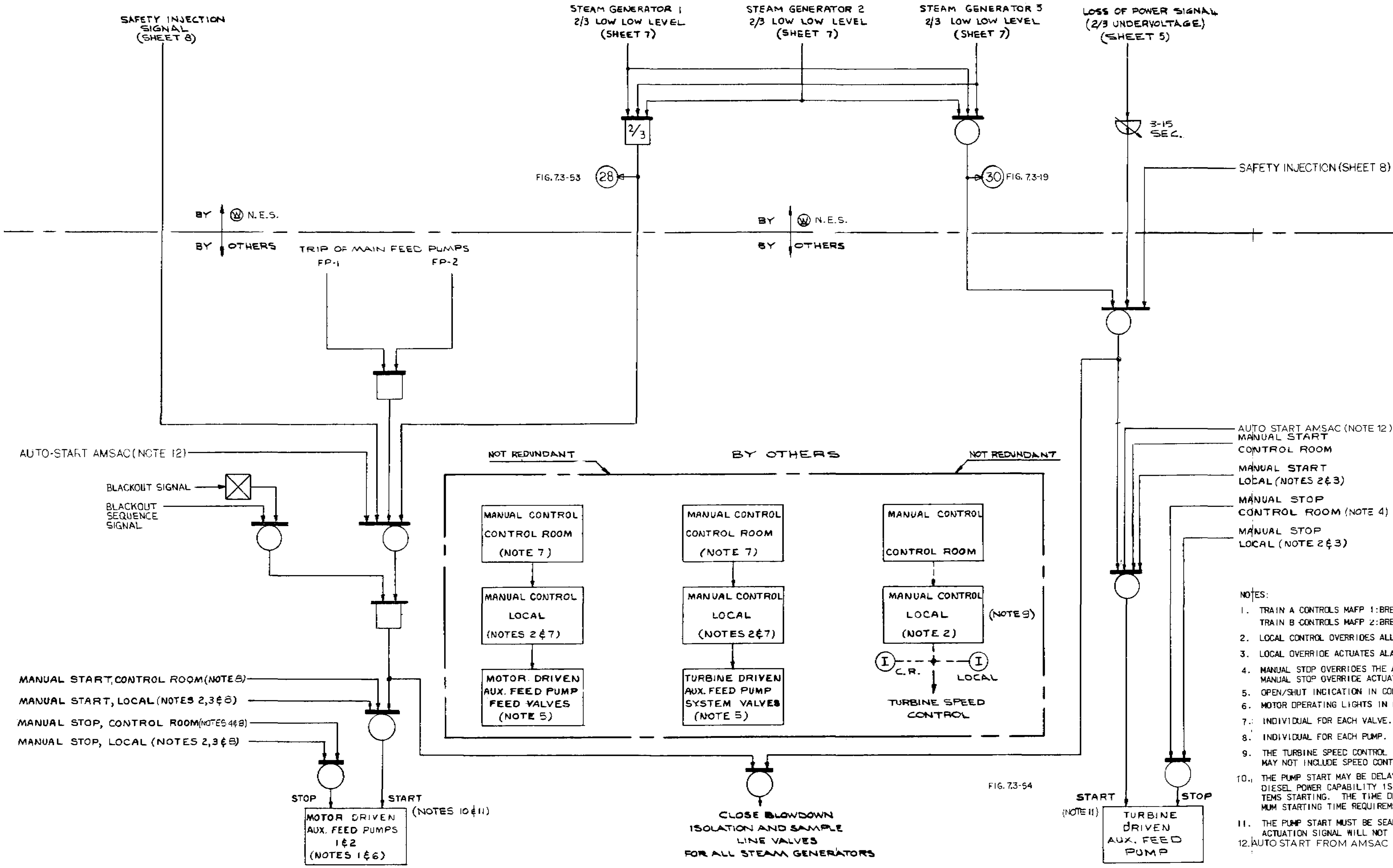
NOTES:

1. ANALOG GATE CONSISTS OF ONE SOLENOID VENT VALVE INTERLOCKING THE AIR LINE BETWEEN EACH VALVE DIAPHRAGM AND ITS ASSOCIATED POSITIONER. THE SOLENOID VALVE IS DE-ENERGIZED TO VENT CAUSING THE FEEDWATER VALVE TO CLOSE IN FIVE SECONDS.
2. ALL CIRCUITS ON THIS SHEET ARE NOT REDUNDANT, EXCEPT WHERE INDICATED "REDUNDANT".
3. OPEN/SHUT INDICATION FOR EACH FEEDWATER VALVE IN CONTROL ROOM.
4. THE MANUAL RESET CONSISTS OF ONE MOMENTARY CONTROL ON THE CONTROL BOARD.
5. TRIPPING OF FEEDWATER PUMPS CAUSES CLOSURE OF ASSOCIATED PUMP DISCHARGE VALVES.
6. THE FEEDWATER PUMPS AND PUMP DISCHARGE VALVES ARE SUPPLIED BY OTHERS.
7. THE STEAM GENERATOR LEVEL SIGNAL USED FOR FEEDWATER CONTROL IS THE MEDIAN (MIDDLE) SIGNAL FOR THE THREE LEVEL CHANNELS.

FIGURE 7.3-18
FUNCTIONAL DIAGRAM
FEEDWATER CONTROL & ISOLATION
BEAVER VALLEY POWER STATION

UPDATED FINAL SAFETY ANALYSIS REPORT

REV 7



NOTES:

1. TRAIN A CONTROLS MAFP 1:BREAKER NUMBER.
   TRAIN B CONTROLS MAFP 2:BREAKER NUMBER.
2. LOCAL CONTROL OVERRIDES ALL OTHER SIGNALS.
3. LOCAL OVERRIDE ACTUATES ALARM IN CONTROL ROOM.
4. MANUAL STOP OVERRIDES THE AUTOMATIC START. MANUAL STOP OVERRIDE ACTUATES ALARM IN CONTROL ROOM.
5. OPEN/SHUT INDICATION IN CONTROL ROOM.
6. MOTOR OPERATING LIGHTS IN CONTROL ROOM.
7. INDIVIDUAL FOR EACH VALVE.
8. INDIVIDUAL FOR EACH PUMP.
9. THE TURBINE SPEED CONTROL IS TYPICAL. ACTUAL IMPLEMENTATION MAY NOT INCLUDE SPEED CONTROL.
10. THE PUMP START MAY BE DELAYED AND SEQUENCED IF THE EMERGENCY DIESEL POWER CAPABILITY IS LESS THAN THE TOTAL LOAD WITH ALL SYSTEMS STARTING. THE TIME DELAY, IF USED, MAY NOT EXCEED THE MAXIMUM STARTING TIME REQUIREMENTS FOR THIS SYSTEM.
11. THE PUMP START MUST BE SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THE PUMP TO STOP.
12. AUTO START FROM AMSAC SYSTEM

FIGURE 7.3-19
FUNCTIONAL DIAGRAM-AUXILIARY FEEDWATER PUMPS STARTUP
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 17

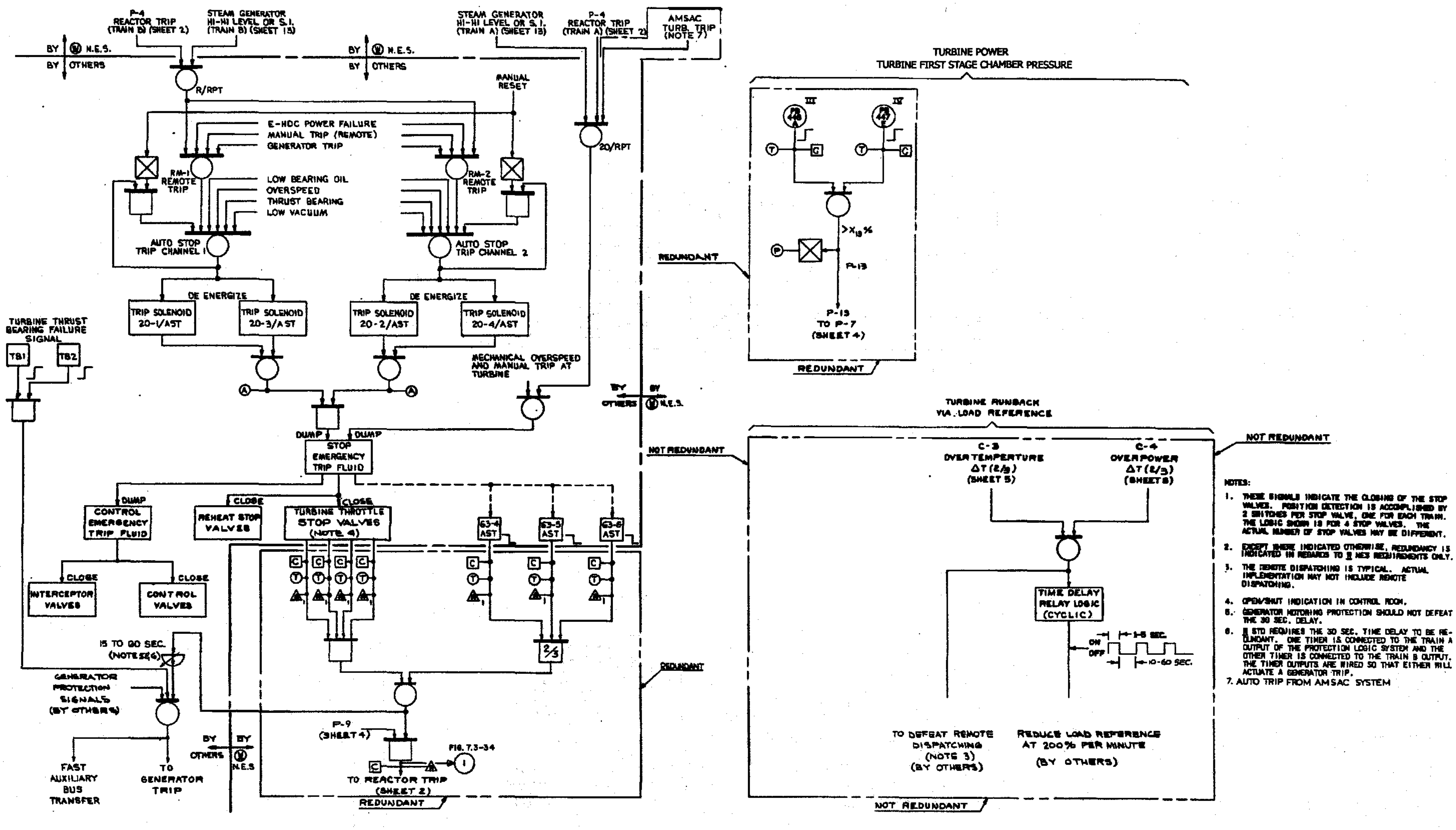
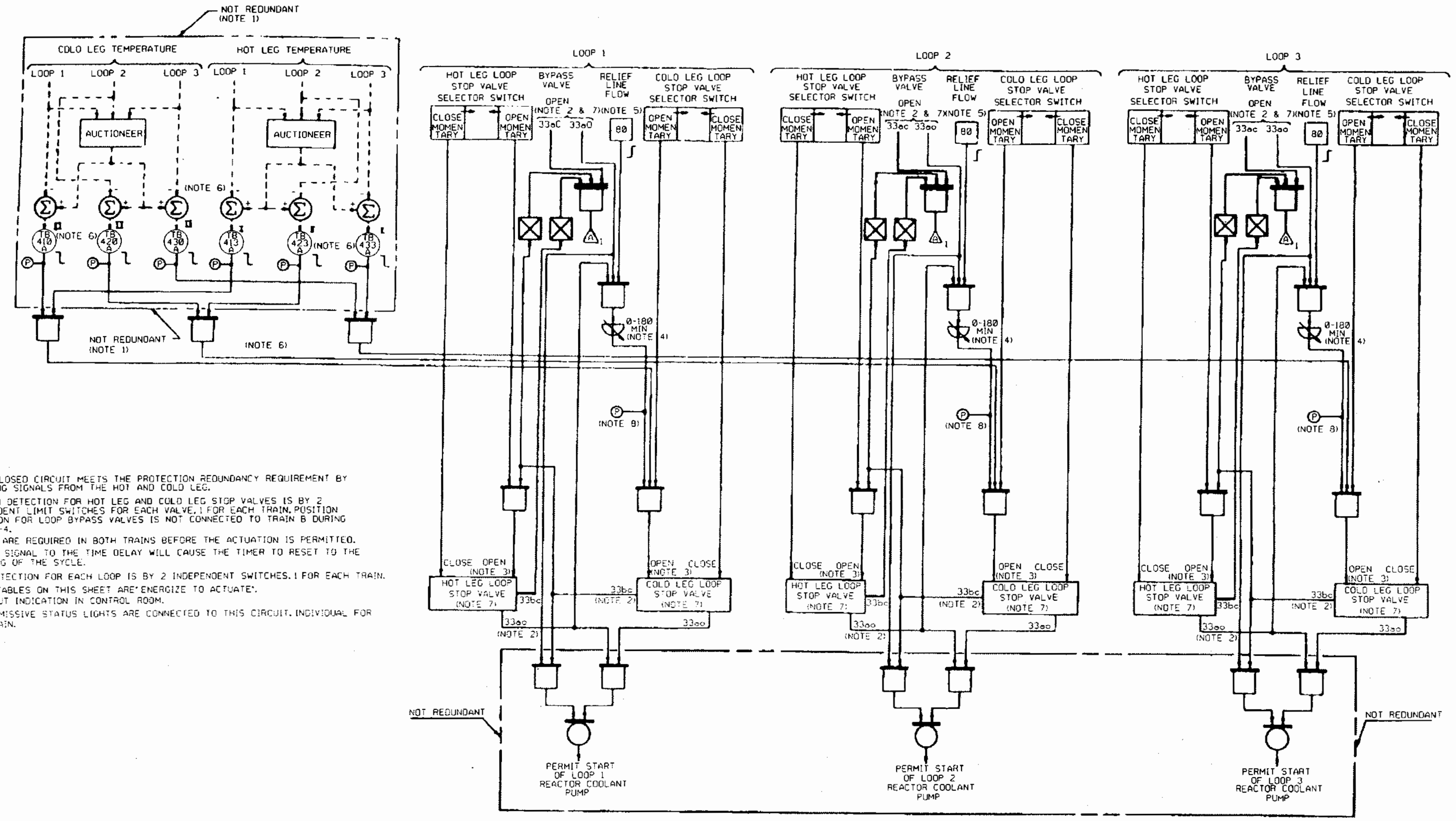


FIGURE 7.3-20

FUNCTIONAL DIAGRAM
TURBINE TRIP, RUNBACKS &
OTHER SIGNALS

(2001.409-001-031, REV. M)

BEAVER VALLEY POWER STATION UNIT No. 2
UPDATED FINAL SAFETY ANALYSIS REPORT



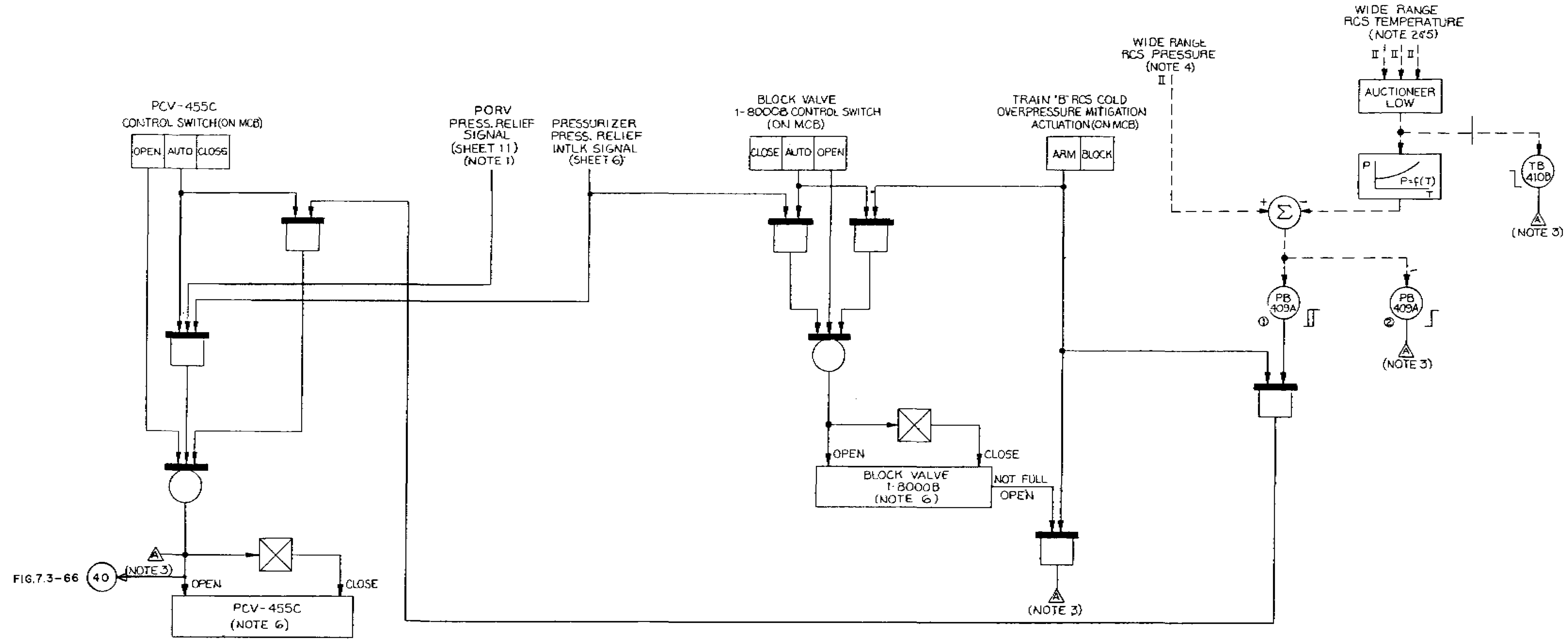
NOTES:

1. THE ENCLOSED CIRCUIT MEETS THE PROTECTION REDUNDANCY REQUIREMENT BY COMBINING SIGNALS FROM THE HOT AND COLD LEG.
2. POSITION DETECTION FOR HOT LEG AND COLD LEG STOP VALVES IS BY 2 INDEPENDENT LIMIT SWITCHES FOR EACH VALVE, 1 FOR EACH TRAIN. POSITION DETECTION FOR LOOP BYPASS VALVES IS NOT CONNECTED TO TRAIN B DURING MODES 1-4.
3. SIGNALS ARE REQUIRED IN BOTH TRAINS BEFORE THE ACTUATION IS PERMITTED.
4. LOSS OF SIGNAL TO THE TIME DELAY WILL CAUSE THE TIMER TO RESET TO THE BEGINNING OF THE SYCLE.
5. FLOW DETECTION FOR EACH LOOP IS BY 2 INDEPENDENT SWITCHES, 1 FOR EACH TRAIN.
6. ALL BISTABLES ON THIS SHEET ARE "ENERGIZE TO ACTUATE".
7. OPEN/SHUT INDICATION IN CONTROL ROOM.
8. TWO PERMISSIVE STATUS LIGHTS ARE CONNECTED TO THIS CIRCUIT. INDIVIDUAL FOR EACH TRAIN.

THIS UFSAR FIGURE SUPERSEDES FIGURE OF SAME NUMBER, REV. 1

FIGURE 7.3-21
FUNCTIONAL DIAGRAM
LOOP STOP VALVE LOGIC
(2001.409-032, REV. J)
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV. 4

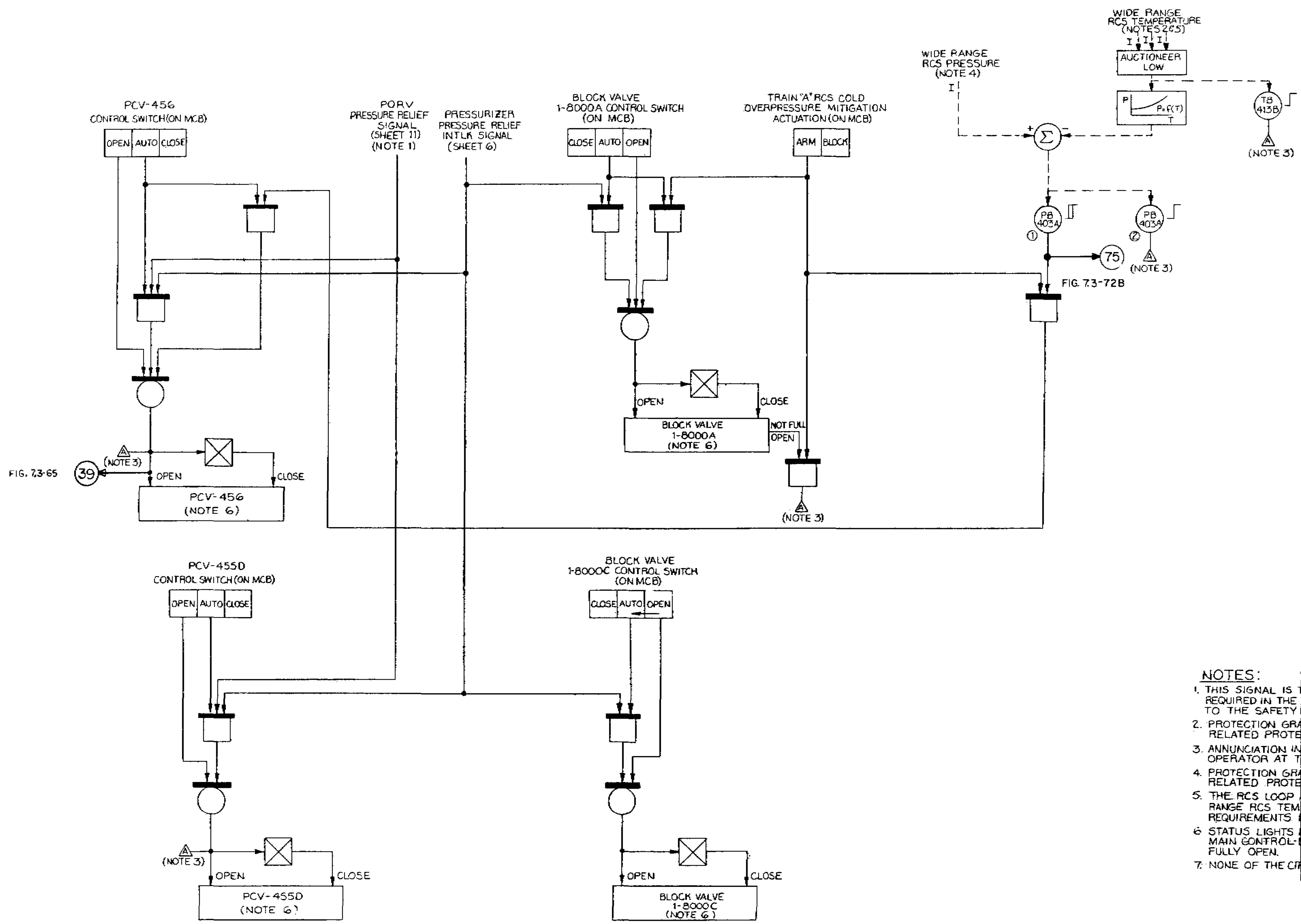


NOTES:

1. THIS SIGNAL IS THE OUTPUT FROM BISTABLE PB-444B. ELECTRICAL ISOLATION IS REQUIRED IN THE TRAIN "B" SSPS CABINET IN ORDER TO CONNECT THIS SIGNAL TO THE SAFETY GRADE CIRCUITS.
2. PROTECTION GRADE WIDE RANGE RCS TEMPERATURE SIGNALS FROM TRAIN "B" RELATED PROTECTION SETS.
3. ANNUNCIATION IN THE MAIN CONTROL ROOM IS REQUIRED TO BE VISIBLE TO THE OPERATOR AT THE MAIN CONTROL BOARD.
4. PROTECTION GRADE WIDE RANGE RCS PRESSURE SIGNAL FROM TRAIN "B" RELATED PROTECTION SET.
5. THE RCS LOOP AND HOT LEG OR COLD LEG ASSIGNMENTS FOR THE WIDE RANGE RCS TEMPERATURE SIGNALS MUST BE CONSISTENT WITH THE REQUIREMENTS FOR PAMS.
6. STATUS LIGHTS MUST PROVIDED FOR EACH PORV AND EACH PORV BLOCK VALVE AT THE MAIN CONTROL BOARD TO INDICATE WHEN THE VALVE IS FULLY CLOSED OR FULLY OPEN.
7. NONE OF THE CIRCUITS ON THIS SHEET ARE REDUNDANT.

FIGURE 7.3-22
FUNCTIONAL DIAGRAM
PRESSURIZER PRESSURE
RELIEF SYSTEM (TRAIN "B")
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

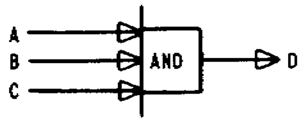
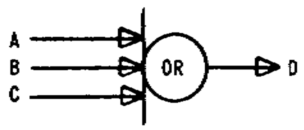
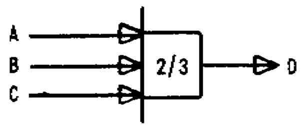
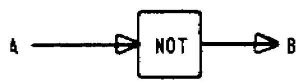
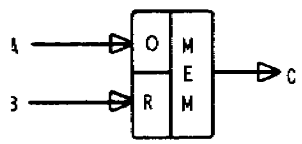
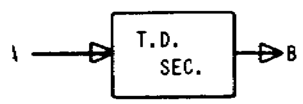
REV. 4

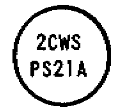
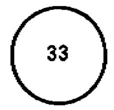
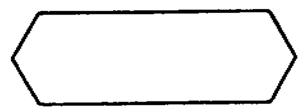
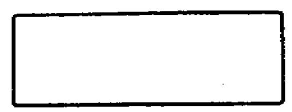
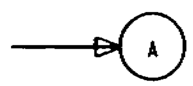
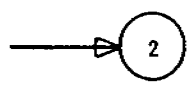


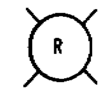
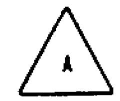
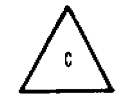
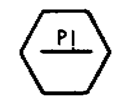
NOTES:

1. THIS SIGNAL IS THE OUTPUT FROM BISTABLE PB 445A. ELECTRICAL ISOLATION IS REQUIRED IN THE TRAIN "A" SSPS CABINET IN ORDER TO CONNECT THIS SIGNAL TO THE SAFETY GRADE CIRCUITS.
2. PROTECTION GRADE WIDE RANGE RCS TEMPERATURE SIGNALS FROM TRAIN "A" RELATED PROTECTION SETS.
3. ANNUNCIATION IN THE MAIN CONTROL ROOM IS REQUIRED TO BE VISIBLE TO THE OPERATOR AT THE MAIN CONTROL BOARD.
4. PROTECTION GRADE WIDE RANGE RCS PRESSURE SIGNAL FROM TRAIN "A" RELATED PROTECTION SET.
5. THE RCS LOOP AND HOT LEG OR COLD LEG ASSIGNMENTS FOR THE WIDE RANGE RCS TEMPERATURE SIGNALS MUST BE CONSISTENT WITH THE REQUIREMENTS FOR PAMS.
6. STATUS LIGHTS MUST BE PROVIDED FOR EACH PORV AND EACH PORV BLK. VALVE AT THE MAIN CONTROL BOARD TO INDICATE WHEN THE VALVE IS FULLY CLOSED OR FULLY OPEN.
7. NONE OF THE CIRCUITS ON THIS SHEET ARE REDUNDANT.

FIGURE 7.3-23
FUNCTIONAL DIAGRAM
PRESSURIZER PRESSURE
RELIEF SYSTEM (TRAIN "A")
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SYMBOL	LOGIC FUNCTION	DESCRIPTION
	AND	ALL INPUTS A, B, AND C ARE REQUIRED BEFORE PROCEEDING TO D.
	OR	ANY INPUT A, B, OR C IS REQUIRED BEFORE PROCEEDING TO D.
	COUNTING	ANY TWO INPUTS A, B, OR C ARE REQUIRED BEFORE PROCEEDING TO D.
	NOT	OUTPUT B EXISTS ONLY WHEN INPUT A DOES NOT EXIST.
	RETENTIVE MEMORY	MOMENTARY INPUT A CAUSES CONTINUOUS OUTPUT C MOMENTARY INPUT B CANCELS OUTPUT C IF INPUT A ABSENT
	TIME DELAY	CONTINUOUS INPUT A PRODUCES OUTPUT B AFTER DESIGNATED TIME, WHEN INPUT IS REMOVED, OUTPUT IS LOST AND TIME DELAY RESET.
	TIME RETENTION	CONTINUOUS INPUT A PRODUCES IMMEDIATE OUTPUT B FOR DESIGNATED RETENTION TIME THEN OUTPUT B IS LOST. RESET BY REMOVAL OF INPUT.

SYMBOL	LOGIC FUNCTION	DESCRIPTION
	INSTRUMENT SOURCE	2 - UNIT NUMBER CWS - SYSTEM CODE REFER TO 2BVM-146 PS - EQUIPMENT IDENT. CODE REFER TO 2BVM-146
	ELECTRICAL SOURCE	27 - UNDERVOLTAGE RELAY 33 - POSITION SWITCH 42 - MAGNETIC STARTER OR CONTACTOR 49 - MACHINE THERMAL RELAY 52 - AC CIRCUIT BREAKER 52H - CELL SWITCH CONTACT-CHANGES STATE WHEN SWITCHGEAR CIRCUIT BREAKER IS REMOVED FROM OPERATING POSITION. 74 - ALARM RELAY
	CONDITION	STATEMENT OF OPERATING STATUS
	CONTROL ACTION	CONTROL DEVICES CS - CONTROL SWTICH PB - PUSHBUTTON SS - SELECTOR SWITCH
	RESULTANT	STATEMENT OF FINAL ACTION
	ALPHABETICAL REFERENCE TO SAME SHEET	
	NUMERICAL REFERENCE TO ANOTHER SHEET	

SYMBOL	LOGIC FUNCTION	DESCRIPTION
	INDICATING LIGHT	R - RED G - GREEN A - AMBER W - WHITE B - BLUE SL - ENGRAVED STATUS LIGHT A - ANNUNCIATOR SEM - SEQUENCE OF EVENTS INPUT
	ALARM	
	COMMON ALARM SIMILAR EQUIPMENT	ANNUNCIATOR SYMBOLS NUMBERED IN THE LOWER RIGHT CORNER ARE COMMON TO OTHER ANNUNCIATORS WITH THE SAME NUMBER FOR THAT SERIES OF LOGIC DIAGRAMS.
	COMPUTER	
	INDICATOR OR RECORDER	L - LEVEL F - FLOW P - PRESSURE AMM - AMMETER

LOCATIONS

ABP - AUXILIARY BOILER CONTROL PANEL
AC - STATION AIR COMPRESSOR PANEL
ASP - ALTERNATE SHUTDOWN PANEL
AHP - AUXILIARY HYDROGEN CONTROL PANEL
B - MAIN CONTROL BOARD
BSC - BUILDING SERVICE CONTROL PANEL
CFP - CHEMICAL FEED CONTROL PANEL
CP - CHLORINATION CONTROL PANEL (UNIT 1)
GWPA - GAS WASTE CONTROL PANEL A (B SIMILAR)
IC - CONTAINMENT INSTRUMENT AIR COMPRESSOR CONTROL PANEL
L - LOCAL
PCP - POST ACCIDENT SAMPLE CONTROL PANEL
M - AT MOTOR
MCC - 480V MOTOR CONTROL CENTER
RC - ROD DRIVE M-G SET CONTROL PANEL
RH - SWITCHYARD RELAY HOUSE
RK - RACK
S - 4160V SWITCHGEAR
SDP - SHUTDOWN PANEL
SP - SAMPLE PANEL
SS - SEC. SYS. SAMP. PANEL
SWP - SOLID WASTE DISPOSAL CONTROL PANEL
TVP - TURBINE ROOM VENT PANEL
US - 480V SWITCHGEAR
VMP - VIBRATION MONITORING PANEL
WC - WATER CHILLER CONTROL PANEL
WNP - WASTE NEUTRALIZING CONTROL PANEL
RM - RADIATION MONITORING CABINET

FIGURE 7.3-24
LOGIC DIAGRAM
DIGITAL SYMBOLS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

SYMBOL	DESCRIPTION
K	PROPORTIONAL
-K	REVERSE PROPORTIONAL
∫	INTEGRAL, RESET
D	DERIVATIVE, RATE
Σ	ADD OR TOTALIZE
Δ	DIFFERENCE
AVG.	AVERAGING
X	MULTIPLYING
÷	DIVIDING
SQ. RT.	SQUARE ROOT
X^N	EXPONENTIAL

SYMBOL	DESCRIPTION
F(X)	NON-LINEAR OR UNSPECIFIED FUNCTION
+	POSITIVE BIAS
-	NEGATIVE BIAS
>	HIGH SELECTING
<	LOW SELECTING
≯	HIGH LIMITING
≮	LOW LIMITING
B → A, C → A, T; B, C, A	DIGITAL INPUT AT UPPER LEFT BLOCK (B→A) ALLOWS INCOMING SIGNAL AT B TO TRANSFER TO A. DIGITAL INPUT AT LOWER LEFT BLOCK (C→A) ALLOWS INCOMING SIGNAL AT C TO TRANSFER TO A.
A/D (TYPICAL)	FOR INPUT/OUTPUT CONVERSION OF THE FOLLOWING: E VOLTAGE, I CURRENT, H HYDRAULIC, P PNEUMATIC, A ANALOG, D DIGITAL
F(T)	TIME FUNCTION
Λ ≮	RATE OF CHANGE LIMITER

SYMBOL	DESCRIPTION
H/A	HAND - AUTOMATIC SELECTOR STATION
ADD → H/A BIAS	HAND - AUTOMATIC SELECTOR STATION WITH BIAS
Δ → K + ∫ (TYPICAL) → H/A SET POINT	HAND - AUTOMATIC SELECTOR STATION WITH SET POINT
H	MANUAL STATION

FIGURE 7.3-25
LOGIC DIAGRAM
ANALOG SYMBOLS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

1. GUIDE LINES TO LOGIC DIAGRAMS

1.1 THE PURPOSE OF THE LOGIC DIAGRAMS IS TO RECORD AN UNDERSTANDING OF THE CONTROL AND INSTRUMENTATION PROVISIONS FOR THE INDIVIDUAL EQUIPMENT COMPONENTS AND SYSTEMS OF THE POWER STATION. THEY ARE, HOWEVER, NOT INTENDED TO SUMMARIZE AND SPECIFY THE HARDWARE THAT IS REQUIRED. THIS WILL BE SHOWN IN DETAIL ON FLOW, ELEMENTARY AND INSTRUMENT-LOOP DIAGRAMS.

1.2 LOGIC DIAGRAMS AND SYSTEM DESCRIPTIONS ARE NOT INTENDED TO REPLACE EQUIPMENT OPERATING INSTRUCTIONS.

1.3 ALL ALARMS ARE LOCATED IN THE CONTROL ROOM UNLESS OTHERWISE NOTED.

1.4 THE ELECTRICAL POWER SOURCE FOR CONTROL AND INSTRUMENTATION IS NOTED ON ONE LINE DIAGRAMS, ELECTRICAL ELEMENTARY DIAGRAMS, AND INSTRUMENT-LOOP DIAGRAMS.

1.5 REFER TO LSK-0-1A AND 1B DIGITAL AND ANALOG SYMBOLS.

1.6 MARK NOS.HAVING AN ASTERISK AND ELECTRICAL OVERCODING INDICATE EQUIPMENT REQUIRED TO FUNCTION DURING OR AFTER AN ACCIDENT.

THE MECHANICAL FLOW PATH AND ELECTRICAL POWER SOURCE AS FOLLOWS:
(AO) MECHANICAL FLOW PATH A,ELECT. POWER SOURCE ORANGE.
(BP) MECHANICAL FLOW PATH B,ELECT.POWER SOURCE PURPLE.
(SG) DENOTES SPARE,ELECT.POWER SOURCE GREEN (CAPABLE OF BEING POWERED FROM EITHER EMERGENCY BUS).
REFER TO 2BVM-12,INSTRUCTIONS FOR PREPARATION OF FLOW DIAGRAMS.

1.7 WITH REGUARD TO EQUIPMENT CAPABLE OF CONTROL FROM THE CONTROL ROOM (B) ALTERNATE SHUTDOWN PANEL (ASP) OR THE SHUTDOWN PANEL (SDP), INDICAT ING LIGHTS ON THE SDP WILL BE ACTUATED ONLY WHEN CONTROL IS AT THE SDP, INDICATING LIGHTS IN THE CONTROL ROOM WILL BE ACTUATED ONLY WHEN CONTROL IS AT THE CONTROL ROOM, AND INDICATING LIGHTS ON THE ASP WILL BE ACTUATED ONLY WHEN CONTROL IS AT THE ASP.

2. MEDIUM VOLTAGE SWITCHGEAR

2.1 THE FOLLOWING IS A LISTING OF CONTROLS AND MONITORING DEVICES WHICH ARE PROVIDED FOR ALL MEDIUM VOLTAGE SWITCHGEAR BUT ARE NOT SHOWN ON THE LOGIC DIAGRAMS.

A. WITH THE BREAKER IN TEST POSITION, THE MAIN DISCONNECTS ARE OPEN AND BREAKER CONTROL IS AVAILABLE AT THE SWITCHGEAR ONLY.

B. WITH THE BREAKER IN THE OPERATE POSITION, THE BREAKER CAN BE OPERATED ONLY REMOTELY, UNLESS OTHERWISE NOTED.

C. STATIONARY CONTACTS LOCATED ON THE BREAKER STRUCTURE ARE USED FOR INTERLOCKING PURPOSES, OPERATION OF THE BREAKER IN THE "TEST" POSITION, OR COMPLETE WITHDRAWAL OF THE BREAKER WILL NOT CAUSE THESE CONTACTS TO CHANGE STATUS.

D. MECHANICAL TRIP SWITCHES AT THE SWITCHGEAR CAN BE USED TO OPEN THE BREAKER MECHANICALLY. THIS MAY BE NECESSARY IF 125 V DC CONTROL POWER IS LOST AT THE TRIP CIRCUIT.

2.2 OPERATION INDICATING LIGHTS LOCATED ON THE MAIN CONTROL BOARD SHOW:

A. WHITE (NORMAL) - BREAKER OPEN
B. RED - BREAKER CLOSED THIS LIGHT ALSO INDICATES THAT POWER IS AVAILABLE AT THE BREAKER TRIP CIRCUIT.
C. WHITE (BRIGHT) - BREAKER OPEN (AUTO TRIP CONDITION)
D. NO LIGHTS ON - WITH CONTROL SWITCH IN "PULL TO LOCK" OR LOSS OF CONTROL PWR OR BREAKER RACKED OUT

2.3 MEDIUM VOLTAGE SWITCHGEAR IS TRIPPED FOLLOWING A SUSTAINED UNDERVOLTAGE INCIDENT, EXCEPT FOR EMERGENCY SWITCHGEAR MOTORS WHICH ARE TRIPPED WILL FOLLOW THE EMERGENCY LOADING PROGRAM.

2.4 MEDIUM VOLTAGE SWITCHGEAR WITH AN AUTO START FEATURE WILL HAVE A MANUALLY RESET LOCKOUT RELAY, LOCATED AT THE SWITCHGEAR, OPERATED BY BREAKER OVERCURRENT OR GROUND CONDITIONS.

3. LOW VOLTAGE SWITCHGEAR

3.1 THE FOLLOWING IS A LISTING OF CONTROLS AND MONITORING DEVICES WHICH ARE PROVIDED FOR LOW VOLTAGE SWITCHGEAR BUT ARE NOT SHOWN ON THE LOGIC DIAGRAMS.

A. WITH THE BREAKER IN TEST POSITION, THE MAIN DISCONNECTS ARE OPEN AND BREAKER CONTROL IS AVAILABLE AT THE SWITCHGEAR ONLY.

B. WITH THE BREAKER IN THE OPERATE POSITION, THE BREAKER CAN BE OPERATED ONLY REMOTELY UNLESS OTHERWISE NOTED.

C. AUXILIARY CONTACTS LOCATED ON THE BREAKER MECHANISM ARE USED FOR INTERLOCKING PURPOSES. OPERATION OF THE BREAKER IN THE TEST POSITION WILL CAUSE THE AUXILIARY CONTACTS TO OPERATE. CELL SWITCHES ARE PROVIDED TO PREVENT INADVERTENT OPERATION OF INTERLOCKED EQUIPMENT.

D. MECHANICAL TRIP SWITCHES AT THE SWITCHGEAR CAN BE USED TO OPEN THE BREAKER MECHANICALLY.

3.2 OPERATION INDICATING LIGHTS SAME AS FOR MEDIUM VOLTAGE SWITCHGEAR, PARAGRAPH 2.2.

3.3 LOW VOLTAGE SWITCHGEAR IS TRIPPED FOLLOWING A SUSTAINED UNDERVOLTAGE INCIDENT, EXCEPT FOR EMERGENCY SWITCHGEAR MOTORS WHICH WILL FOLLOW THE EMERGENCY LOADING PROGRAM.

3.4 OVERCURRENT PROTECTION WILL REQUIRE MANUAL RESET AT THE SWITCHGEAR.

4. LOW VOLTAGE MOTOR CONTROL CENTER (MCC) MOTORS

4.1 LOW VOLTAGE MCC MOTORS, ARRANGED FOR MAINTAINED START WILL RESTART WHEN POWER IS RESTORED FOLLOWING AN UNDERVOLTAGE INCIDENT.

4.2 START SIGNAL WILL BE MOMENTARY UNLESS OTHERWISE NOTED.

4.3 THERMAL OVERLOAD PROTECTION TRIPS WILL REQUIRE MANUAL RESET AT MCC.

4.4 OPERATION INDICATING LIGHTS SHOW:

A. GREEN - MAGNETIC STARTER DE-ENERGIZED
B. RED - MAGNETIC STARTER ENERGIZED
C. NO LIGHTS ON - WITH CS IN "PULL TO LOCK" OR LOSS OF CONTROL POWER.

5. MOTOR OPERATED VALVES

5.1 UNLESS OTHERWISE NOTED ON THE LOGIC DIAGRAMS, ALL MOTOR OPERATED VALVES WILL, ONCE INITIATED, GO FULL TRAVEL UNTIL STOPPED IN FULL-OPEN OR FULL-CLOSED POSITION. WHEN TORQUE SEATING IS REQUIRED, THE LOGIC DIAGRAM WILL SO STATE.

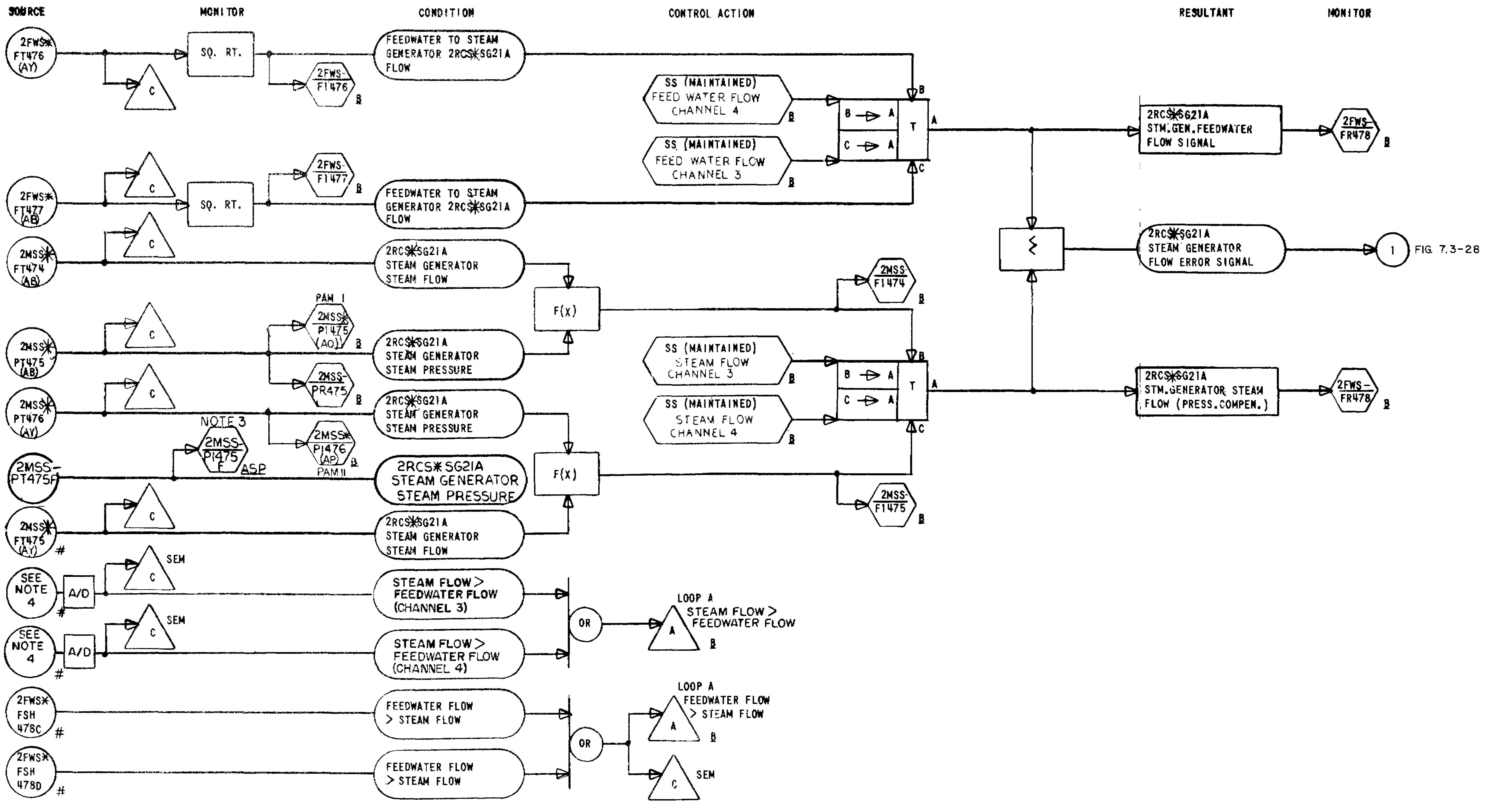
5.2 IF ON THE LOGIC DIAGRAMS THROTTLING SERVICE IS REQUIRED FOR A VALVE, THE VALVE TRAVEL WILL STOP WHEN THE "OPEN" OR "CLOSE" SIGNAL IS REMOVED.

5.3 NORMAL VALVE TRAVEL IS ONLY STOPPED IN AN INTERMEDIATE POSITION BY MOTOR OVERLOAD OR HIGH TORQUE. THE ABOVE CONDITIONS ARE BYPASSED WHEN CERTAIN VALVES ARE PERFORMING A SAFETY FUNCTION

5.4 OPERATION INDICATING LIGHTS SHOW:

A. GREEN - VALVE CLOSED
B. RED - VALVE OPEN
C. RED AND GREEN - VALVE IN AN INTERMEDIATE POSITION.
D. NO LIGHTS ON - WITH CS IN "PULL TO LOCK" OR LOSS OF CONTROL POWER.

FIGURE 7.3-26
LOGIC DIAGRAM
GENERAL NOTES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR LOOP 21 SHOWN. LOGIC FOR LOOPS 22 AND 23 SIMILAR.
2. # BY WESTINGHOUSE.
3. LOGIC FOR 2MSS-PI475F ON LOOP 21 FOR ALTERNATE SHUTDOWN PANEL SHOWN. LOGIC FOR 2MSS-PI485F ON LOOP 22 FOR ALTERNATE SHUTDOWN PANEL SIMILAR.
4. STEAM FLOW > FEEDWATER FLOW IS A RESULT OF A COMPUTER CALCULATION BASED ON STEAM FLOW, STEAMLINE PRESSURE, AND FEEDWATER FLOW.

FIGURE 7.3-27
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

No. 10080-LSK-5-4B

NOTES:
1. * BY WESTINGHOUSE.
2. LOGIC FOR LOOP 21 SHOWN. LOGIC FOR LOOP 22 AND LOOP 23 SIMILAR.
3. SWITCH COMMON TO ALL LOOPS.
4. LOGIC FOR 2FWS-LI477F ON LOOP 21 FOR ALTERNATE SHUTDOWN PANEL SHOWN. LOGIC FOR 2FWS-LI487F ON LOOP 22 FOR ALTERNATE SHUTDOWN PANEL SIMILAR.
5. DELETED
6. DELETED
7. ALL ASTERISKS (*) HAVE BEEN REPLACED BY DASHES. REFER TO THE ASSET EQUIPMENT LIST (AEL) AS THE OFFICIAL LISTING OF ANY ASSET'S QA CATEGORY.
8. F(X) OUTPUT IS CONSTANT SG LEVEL CONTROL SETPOINT EQUAL TO 44% AT ALL POWER LEVELS.

15 ECP 03-0483

FINALIZED FLUID SYSTEM
UFSAR FIGURE 7.3-28
O.M. FIGURE 24-5B

ISSUES			
14	MINOR DWG. CHANGE CR-01-2733 ADDED UFSAR FIG. NO.	ENG: N/A SUP: TGZ for R. DREW 11-19-01 MGR: N/A	MGB 11-10-01 D/CHK: RJK,TGZ
15	ECP 03-0483 CR 03-09276 INCORPORATED IDCN 2-LSK-005-004B-E03-0483-01.	SUP:	RWR 10/23/03 D/CHK: JJD

MINOR DWG. CHANGES ADDED NOTE 7. DELETED NOTE 6.

FENOC FIRSTENERGY NUCLEAR OPERATING COMPANY

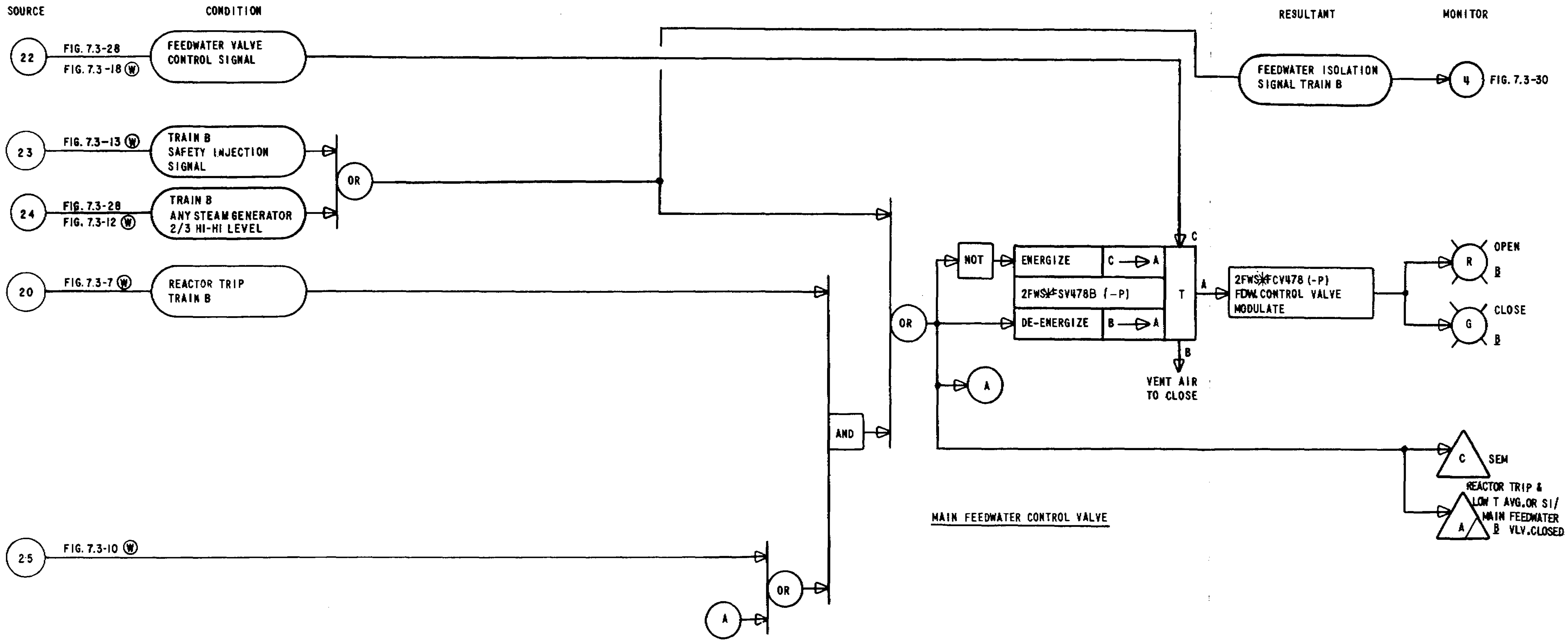
BEAVER VALLEY POWER STATION UNIT 2

LOGIC DIAGRAM
MAIN FEEDWATER CONTROL

SCALE N/A	DATE 11-30-93	ARCH.APP.	FPE: N/A
	DRAWN BY KKR	ELECT.APP.	
	DFG./CHK RWK FMC	MECH.APP.	
	ENGR./CHK BLP TAS	CIVIL APP.	

FINAL APP. FOR ISSUE DIR.EE: KEH 1-8-94
O.F.E. NO. — STA. NO. 100014 — A — D.C.P. NO. 1596
DWG.NO. 10080-LSK-5-4B REV. 15

PREPARED ON THE BVPS CAEDDI SYSTEM

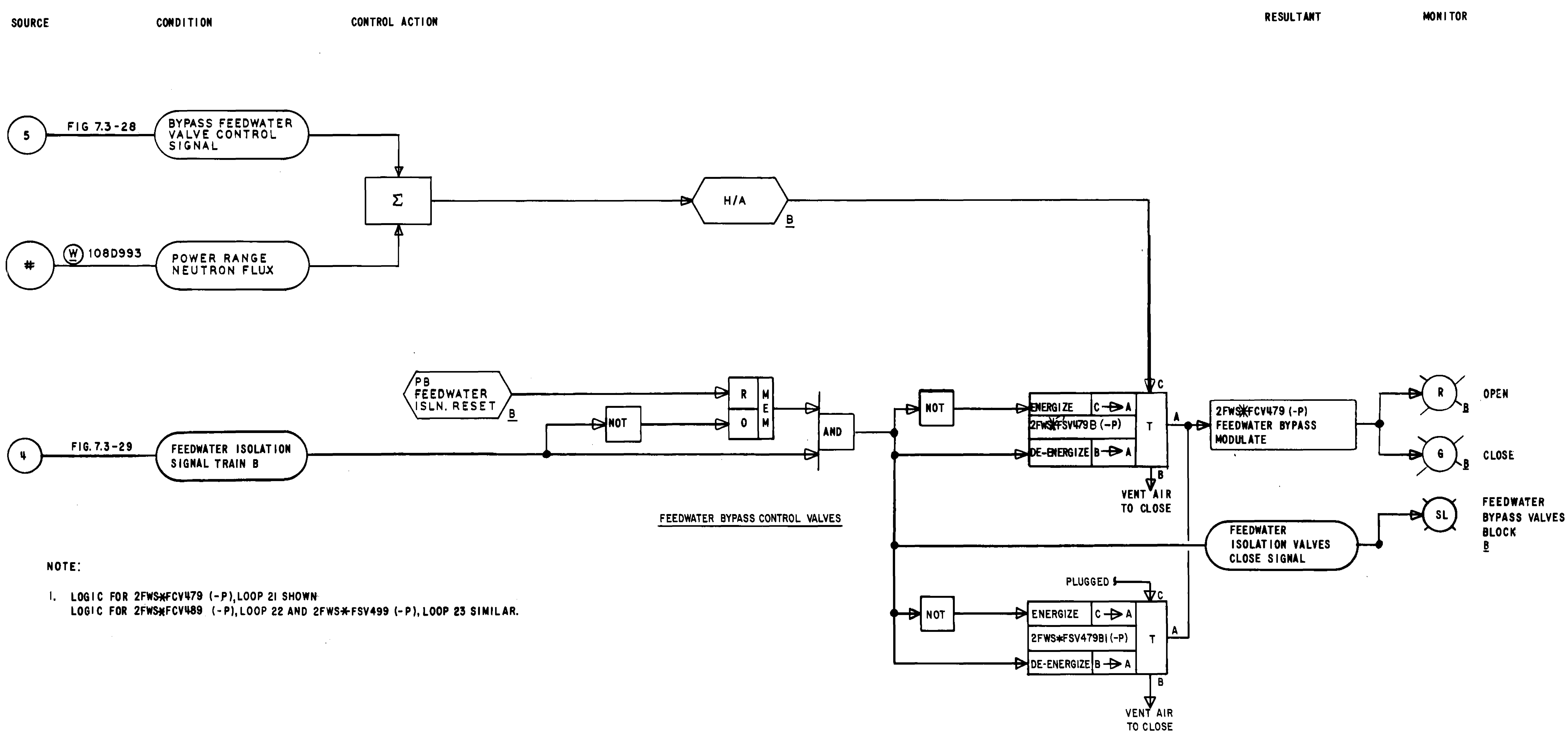


NOTES:

1. LOGIC FOR 2FWS*FCV478 (-P), LOOP 21 SHOWN
   LOGIC FOR 2FWS*FCV488 (-P), LOOP 22 AND 2FWS*FCV498 (-P), LOOP 23 SIMILAR.
2. # BY WESTINGHOUSE

FIGURE 7.3-29
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

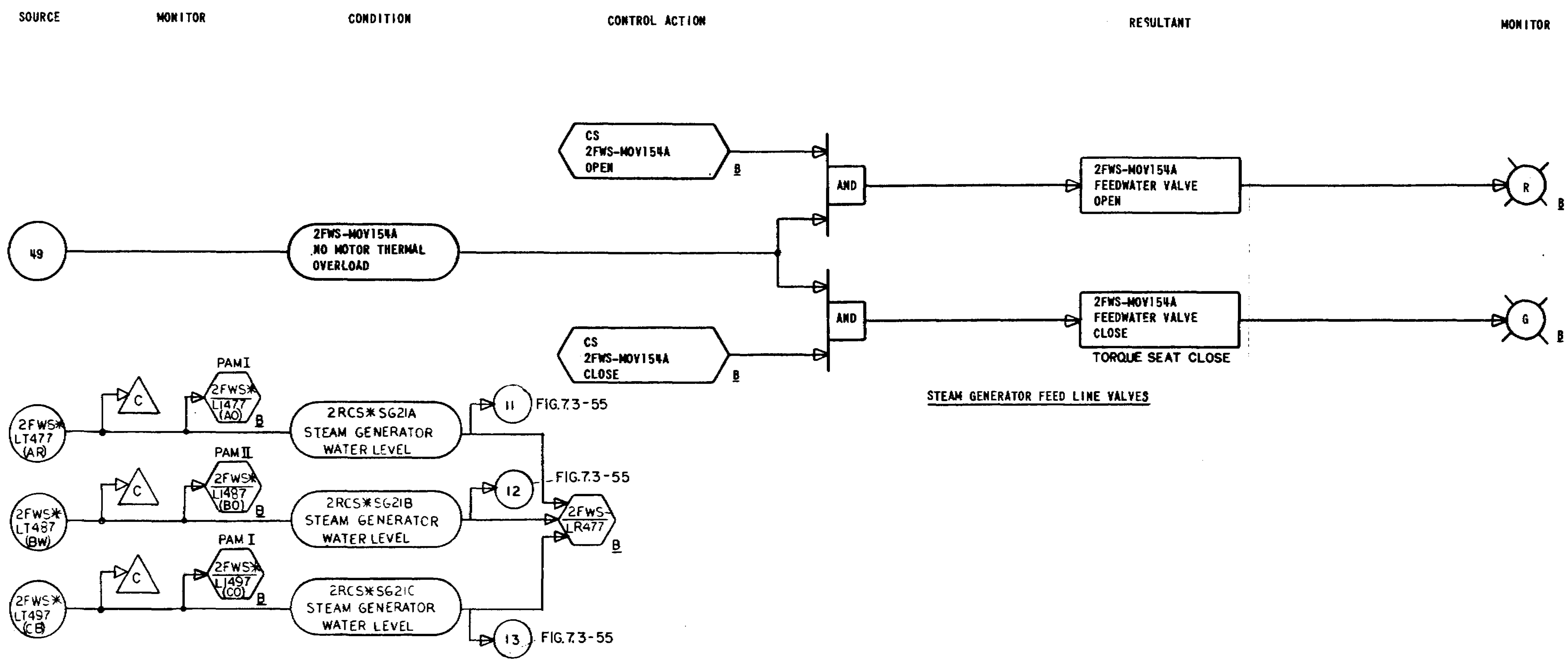
REV 12



NOTE:

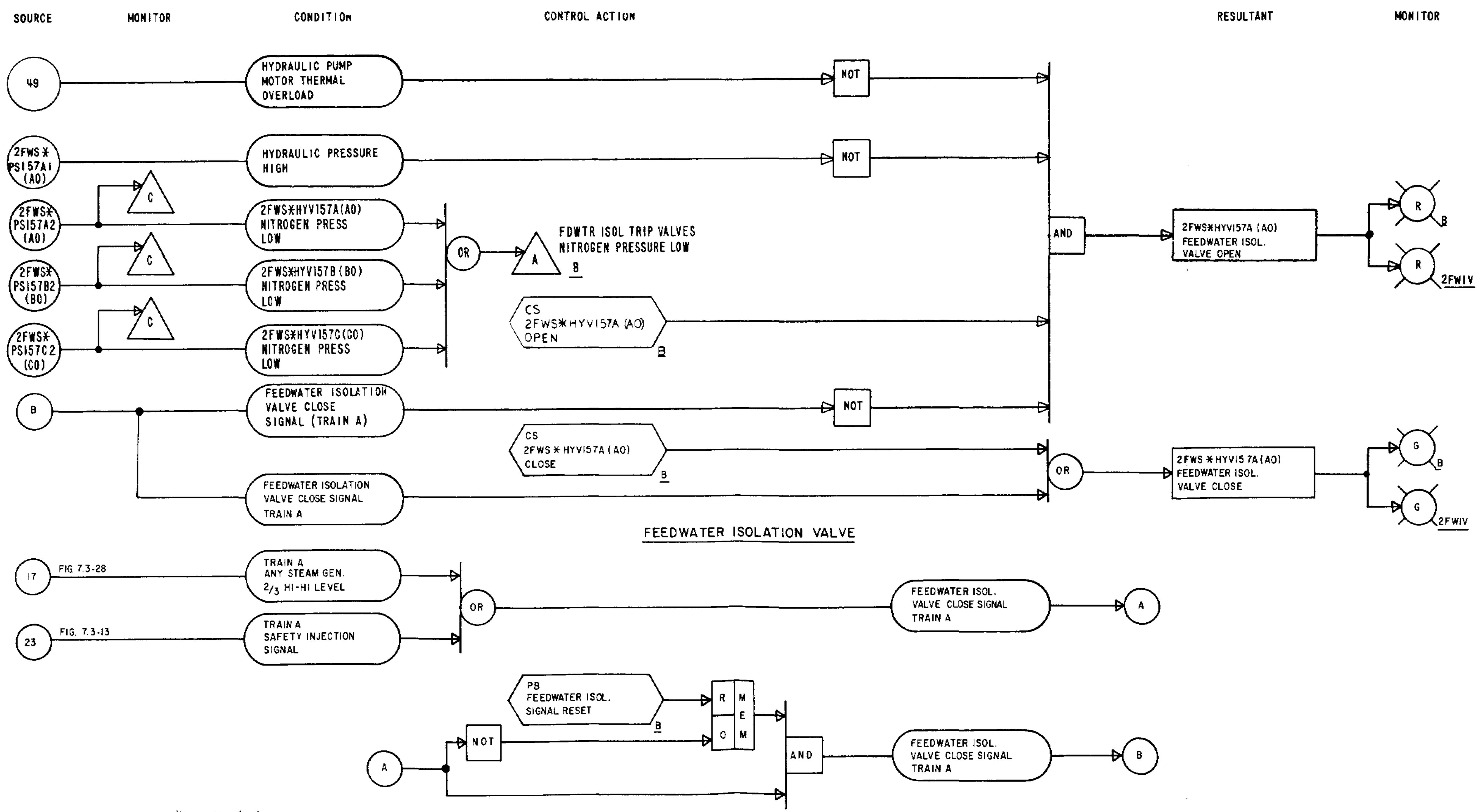
1. LOGIC FOR 2FWS*FCV479 (-P), LOOP 21 SHOWN
   LOGIC FOR 2FWS*FCV489 (-P), LOOP 22 AND 2FWS*FSV499 (-P), LOOP 23 SIMILAR.

FIGURE 7.3-30
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES: 1. LOGIC FOR 2FWS-MOV154A SHOWN.
LOGIC FOR 2FWS-MOV154B AND C, AND 2FWS-MOV155A, B, AND C SIMILAR.

FIGURE 7.3-31
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

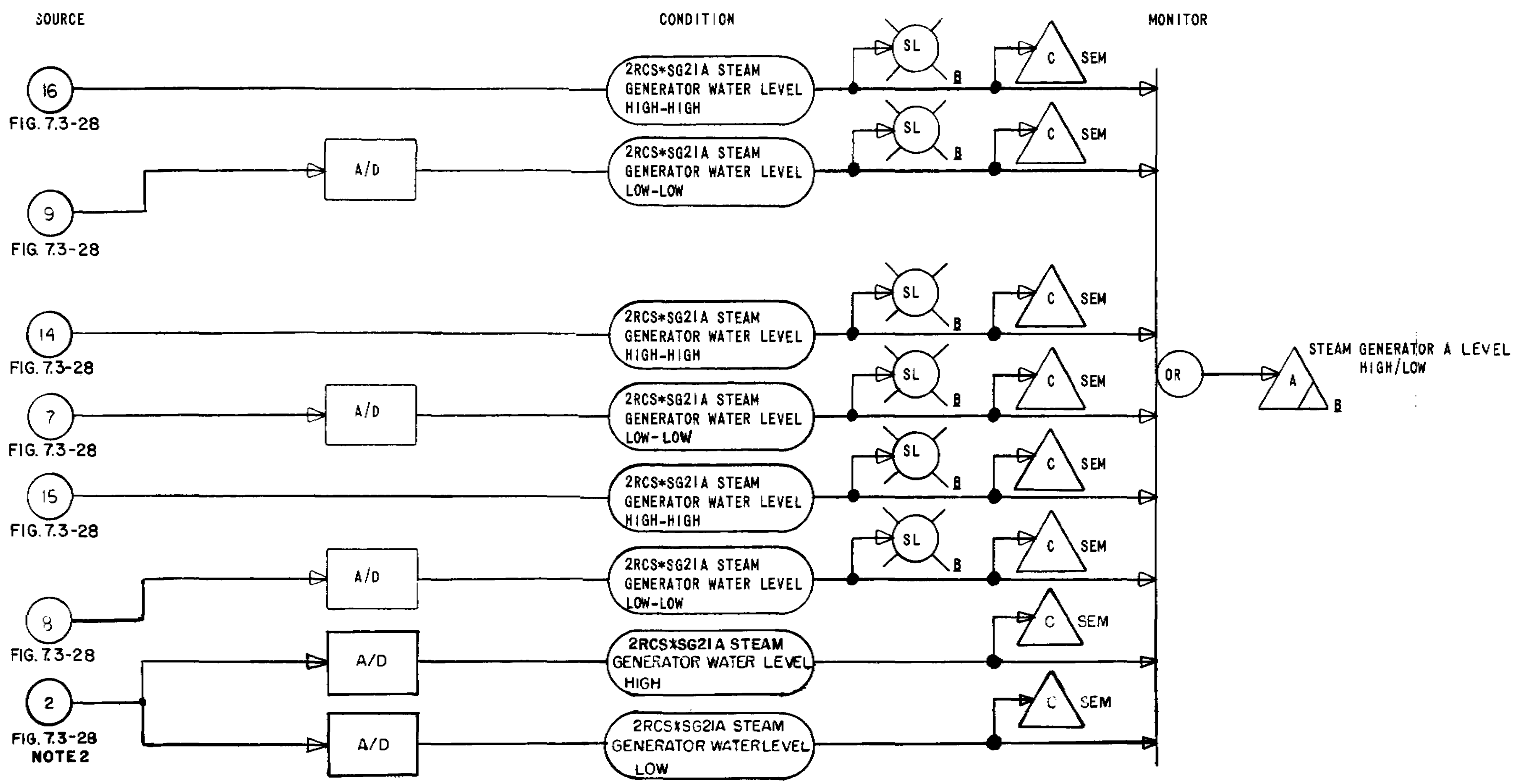


NOTES: 1. LOGIC FOR 2FWS*HYV157A (AO) SHOWN. LOGIC FOR 2FWS*HYV157B (BO), AND 2FWS*HYV157C (CO) SIMILAR.

2. VALVE FAILS AS IS ON LOSS OF POWER.

FIGURE 7.3-32
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 7

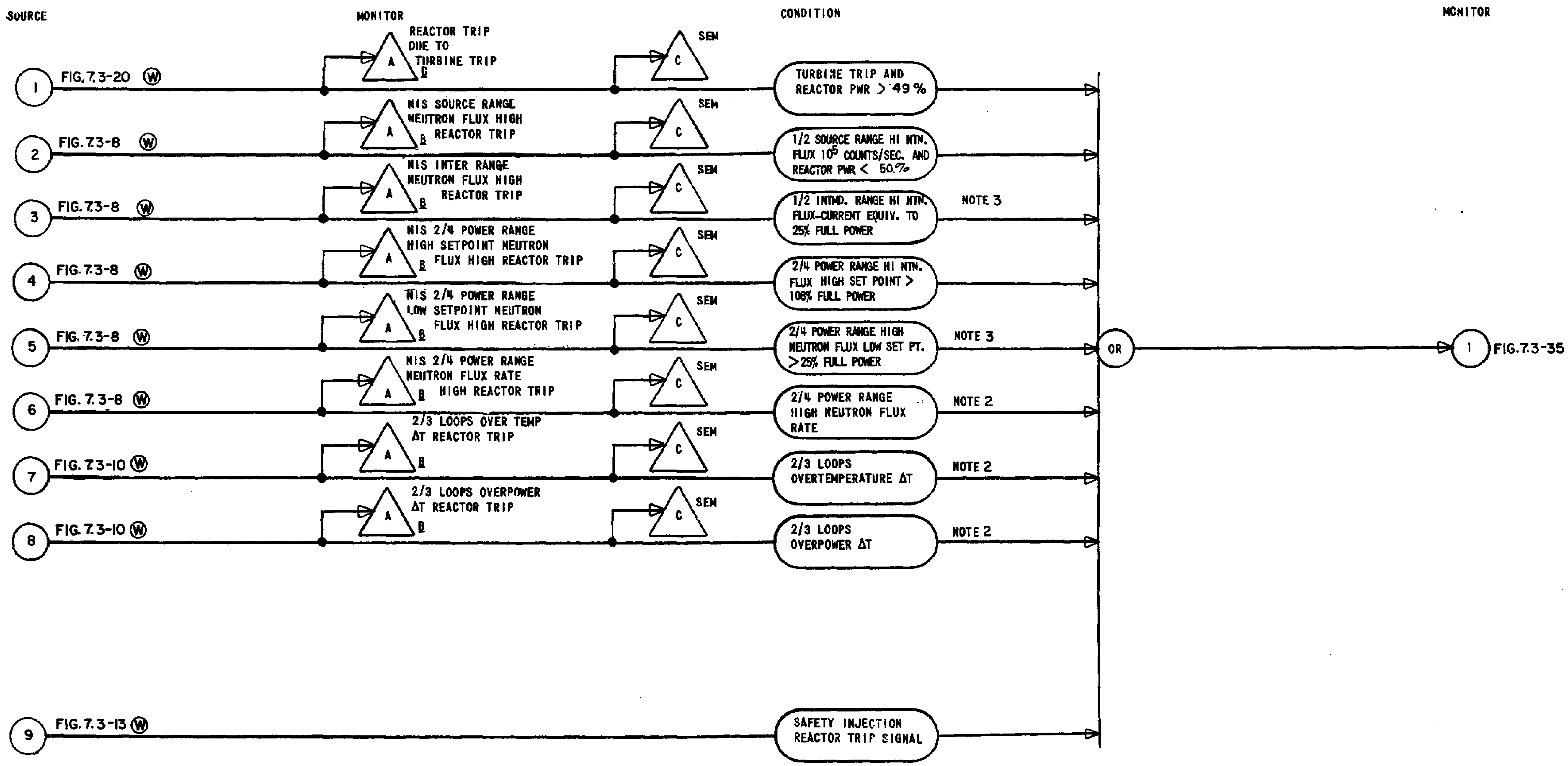


NOTES:

1. LOGIC FOR STEAM GENERATOR 2RCS*SG21A WATER LEVEL SHOWN.
   LOGIC FOR STEAM GENERATORS 2RCS*SG21B AND 2RCS*SG21C SIMILAR.
2. STEAM GENERATOR LEVEL IS THE RESULT OF A COMPUTER CALCULATION.

FIGURE 7.3-33
LOGIC DIAGRAM
MAIN FEEDWATER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 10 (97)



NOTES:

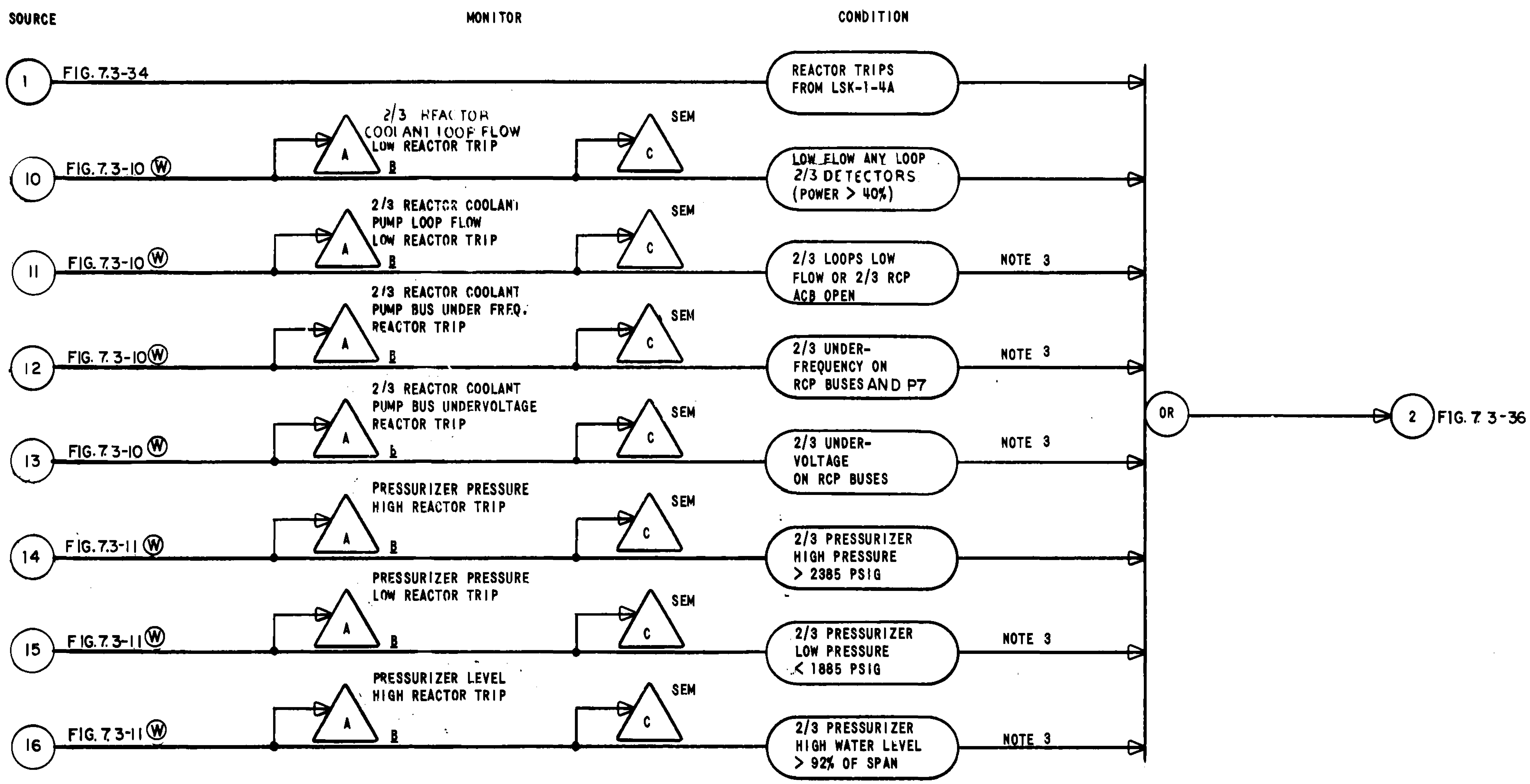
1. TRAIN A SHOWN, TRAIN B SIMILAR.

2. FOR SETPOINT INFORMATION REFER TO WESTINGHOUSE MANUAL - "PRECAUTIONS, LIMITATIONS, AND SET POINTS FOR NUCLEAR STEAM SUPPLY SYSTEMS".

3. MANUAL BLOCK OF THIS TRIP IS PROVIDED ABOVE A PRESET PERMISSIVE VALUE (REACTOR POWER > 50%.)

4. ANNUNCIATORS, AND COMPUTER INPUTS COMMON TO BOTH TRAINS.

FIGURE 7.3-34
LOGIC DIAGRAM
REACTOR TRIPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:
1. TRAIN A SHOWN, TRAIN B SIMILAR.
2. ANNUNCIATORS AND COMPUTER INPUTS COMMON TO BOTH TRAINS.
3. THESE TRIPS ARE CONDITIONED BY TURBINE IMPULSE CHAMBER PRESSURE > 10% LOAD OR 2/4 REACTOR POWER > 10% (SEE WESTINGHOUSE DRAWING NO. 108D993 SHEET 4).

FIGURE 7.3-35
LOGIC DIAGRAM
REACTOR TRIPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12

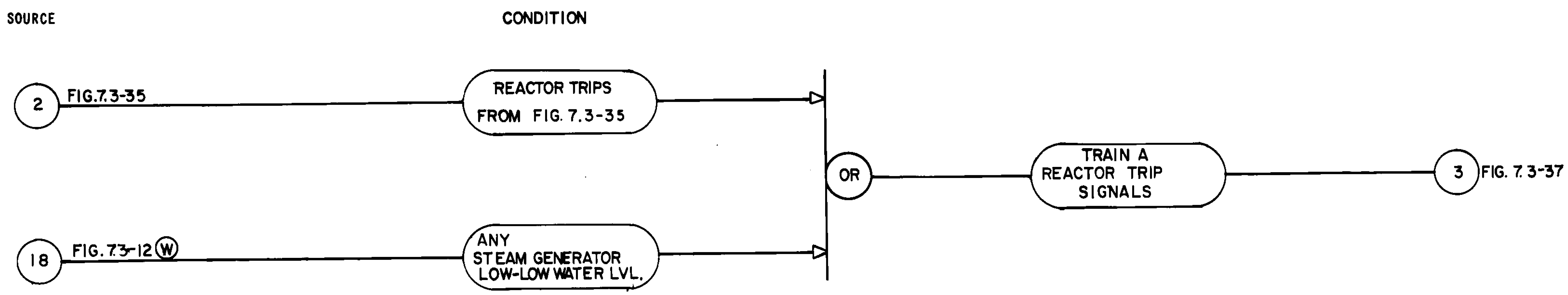
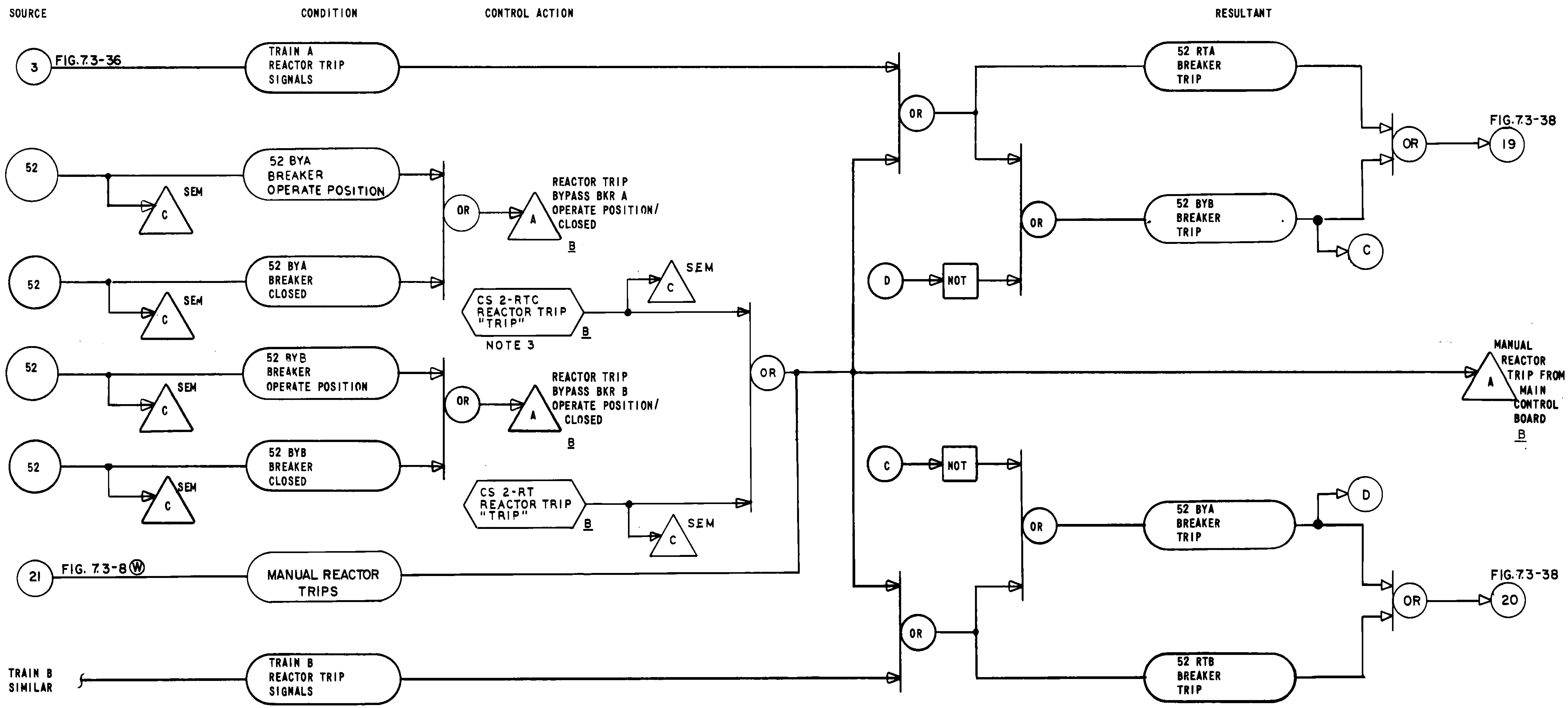


FIGURE 7.3-36
LOGIC DIAGRAM
REACTOR TRIPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12



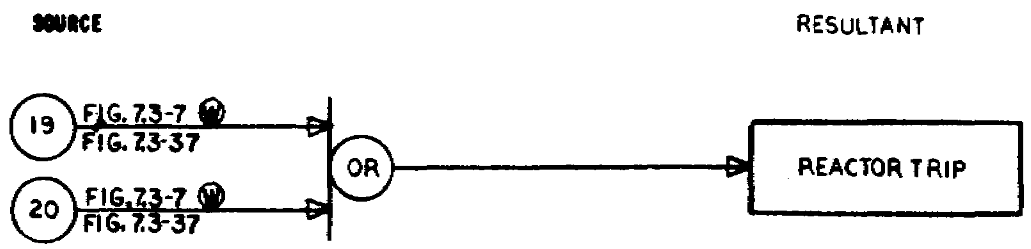
NOTES:

1. NORMAL OPERATION IS WITH REACTOR TRIP BREAKERS 52 RTA AND 52 RTB IN SERVICE AND BYPASS BREAKERS 52 BYA AND 52 BYB WITHDRAWN.

2. THE BYPASS BREAKER INTERLOCK IS OPERATIVE ONLY WHEN BOTH BYPASS BREAKERS ARE IN THE OPERATE POSITION (RACKED IN).

3. CS 2-RTC IS ABLE TO CLOSE THE BREAKERS AS WELL AS TRIP THEM. CS 2-RT IS ONLY ABLE TO TRIP THE BREAKERS.

FIGURE 7.3-37
LOGIC DIAGRAM
REACTOR TRIPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. REACTOR TRIP RESULTS IN TURBINE TRIP, FEEDWATER ISOLATION, AND SAFETY INJECTION RESET AND BLOCK PERMISSIVE.

FIGURE 7.3-38
LOGIC DIAGRAM
REACTOR TRIPS

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

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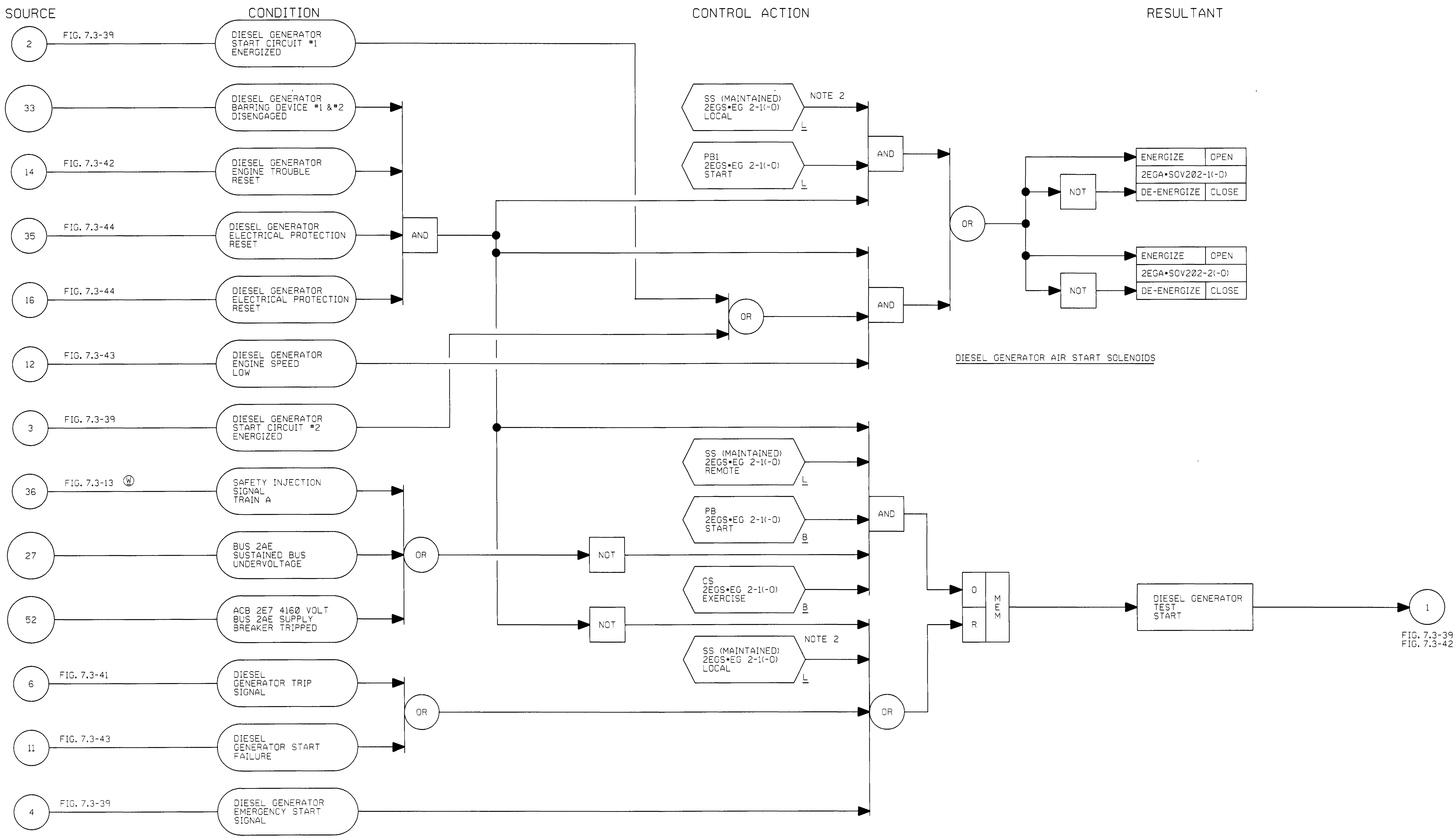
NOTES:
1. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-1(-O) SHOWN. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-2(-P) SIMILAR EXCEPT NO CONTROL AVAILABLE FROM ALT SHUTDOWN PANAL.
2. CONTROL AT ALTERNATE SHUTDOWN PANEL.
3. # BY WESTINGHOUSE
4. KEYLOCKED, KEY REMOVABLE IN REMOTE POSITION.

FIGURE 7.3-39
LOGIC DIAGRAM
EMERGENCY GENERATOR STARTING
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

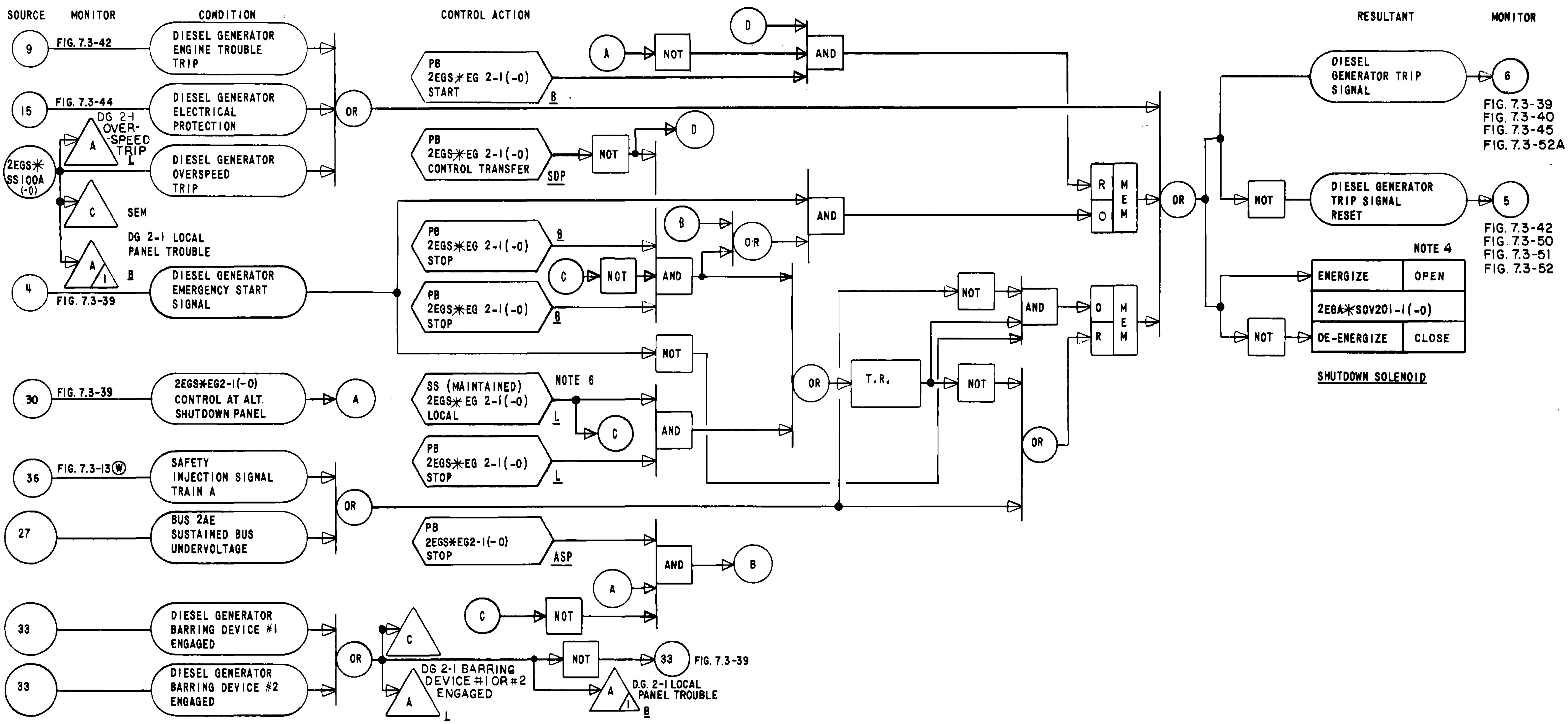
REV 12



NOTES:
1. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-1(-O) SHOWN. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-2(-P) SIMILAR.
2. KEY LOCKED, KEY REMOVABLE IN REMOTE POSITION.

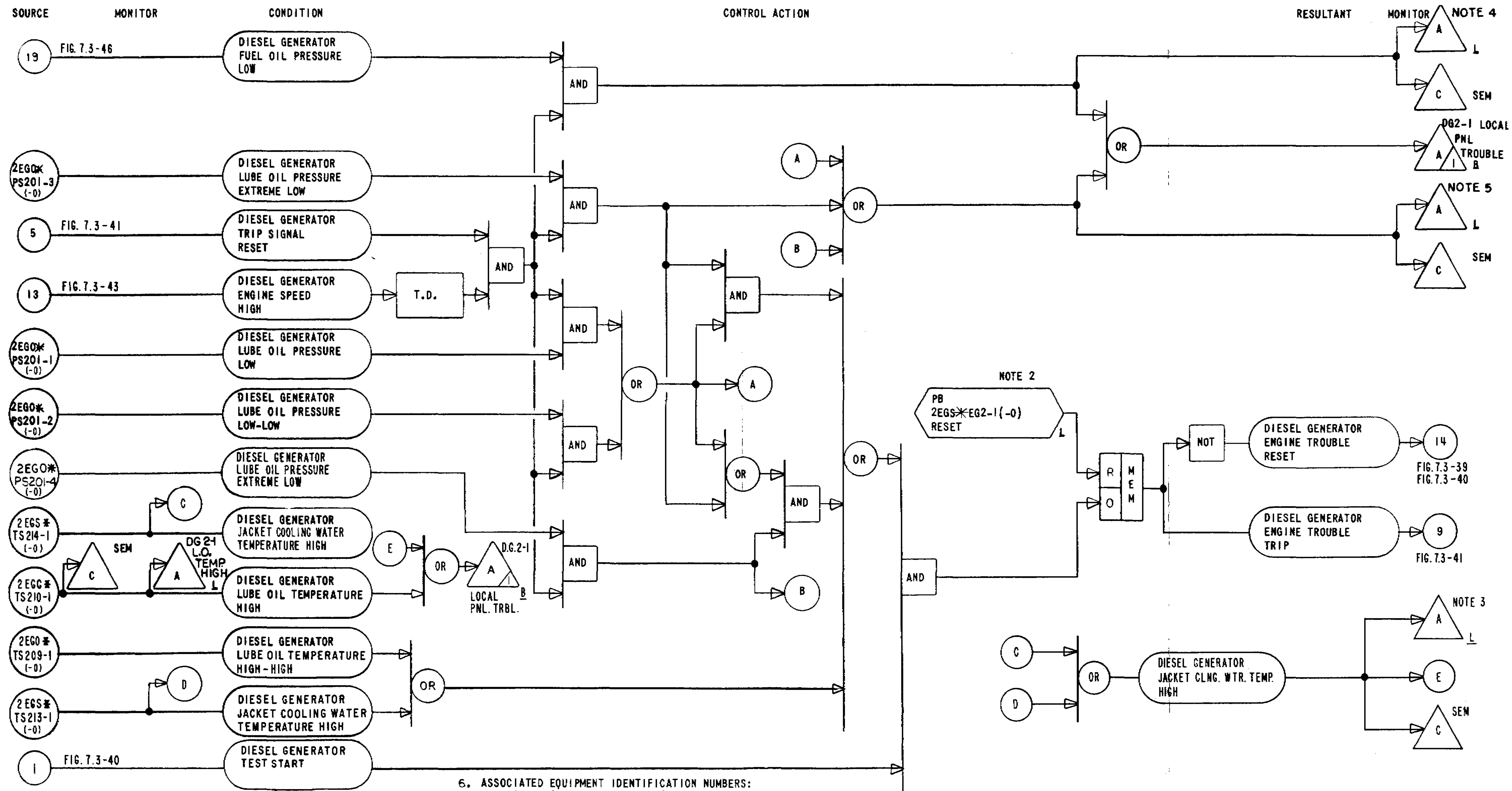
FIGURE 7.3-40
LOGIC DIAGRAM
EMERGENCY GENERATOR STARTING
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12



NOTES:
1. LOGIC FOR DG 2-1 SHUTDOWN SOLENOID 2EGA✱SOV201-1(-0) IS SHOWN. LOGIC FOR DG 2-2 SHUTDOWN SOLENOID 2EGA✱SOV201-2(-P) IS SIMILAR EXCEPT NO CONTROL FROM ASP.
2. LOGIC FOR CONTROL FROM THE CONTROL ROOM IS SHOWN. LOGIC FOR CONTROL FROM THE SHUTDOWN PANEL IS SIMILAR.
3. CONTROL FROM THE CONTROL ROOM IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER RELAY HAS BEEN MANUALLY RESET. CONTROL FROM THE SHUTDOWN PANEL IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER RELAY IS ACTUATED.
4. ENERGIZING SHUTDOWN SOLENOID 2EGA✱SOV201-1 WILL ADMIT AIR TO THE FUEL RACK BOOST SOURCE CYLINDER ISOLATING DIESEL GENERATOR FUEL OIL SUPPLY.
5. NO CONTROL AVAILABLE FROM ALTERNATE SHUTDOWN PANEL FOR 2EGS✱EG2-2 (-P).
6. KEYLOCKED, KEY REMOVABLE IN REMOTE POSITION.
7. RESET FROM MB SHOWN, RESET FROM SDP AND ASP SIMILAR.

FIGURE 7.3-41
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

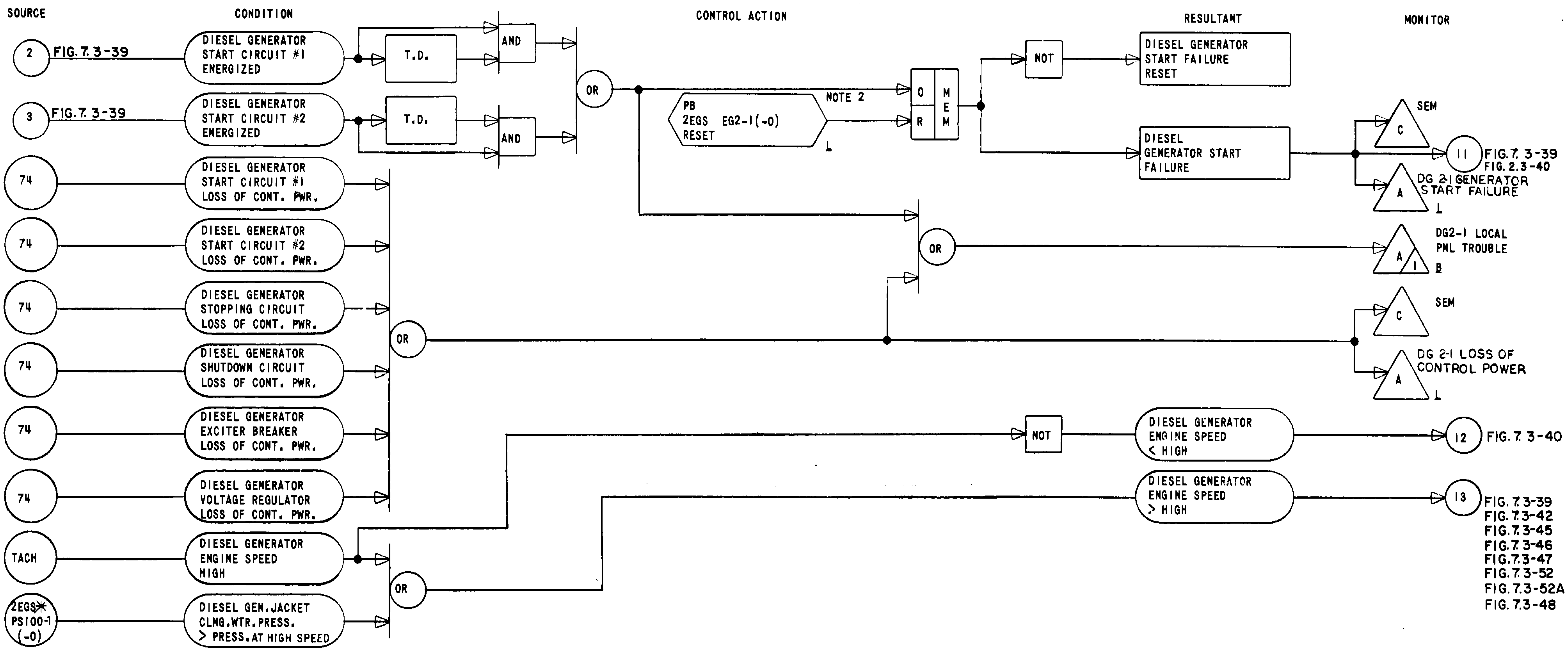
1. LOGIC FOR DIESEL GENERATOR 2EGS✱EG2-1(-0) ENGINE TRBL. SHOWN
   LOGIC FOR DIESEL GENERATOR 2EGS✱EG2-2(-P) ENGINE TRBL. SIMILAR
2. FOR ADDITIONAL RESET PUSHBUTTON INTERLOCKS REFER TO LSK-22-6E
3. DG 2-1 JACKET COOLING WATER TEMPERATURE HIGH
4. DG 2-1 FUEL OIL PRESSURE LOW
5. DG 2-1 LUBE OIL PRESSURE LOW

6. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS✱EG2-1(-0)	2EGS✱EG2-2(-P)
2EGO✱PS201-1(-0)	2EGO✱PS202-1(-P)
2EGO✱PS201-2(-0)	2EGO✱PS202-2(-P)
2EGO✱PS201-3(-0)	2EGO✱PS202-3(-P)
2EGO✱PS201-4(-0)	2EGO✱PS202-4(-P)
2EGF✱PS202-1(-0)	2EGF✱PS202-2(-P)
2EGO✱TS210-1(-0)	2EGO✱TS210-2(-P)
2EGS✱TS214-1(-0)	2EGS✱TS214-2(-P)

FIGURE 7.3-42
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12



NOTES:

1. LOGIC FOR DIESEL GENERATOR 2EGS✱EG2-1(-0) START FAILURE SHOWN.
   LOGIC FOR DIESEL GENERATOR 2EGS✱EG2-2(-P) START FAILURE SIMILAR.
2. FOR ADDITIONAL RESET PUSHBUTTON INTERLOCKS REFER TO FIG. 7.3-42
3. LOGIC FOR JACKET COOLING WATER TEMPERATURE CONTROL VALVE 2EGS✱TCV216-1 (-0) SHOWN.
   LOGIC FOR JACKET COOLING WATER TEMPERATURE CONTROL VALVE 2EGS✱TCV216-2 (-P) SIMILAR.
4. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS✱EG2-1(-0)	2EGS✱EG2-2(-P)
2EGS✱PS100A(-0)	2EGS✱PS100B(-P)
2EGS✱TT216-1(-0)	2EGS✱TT216-2(-P)
2EGS✱TCV216-1(-0)	2EGS✱TCV216-2(-P)
2EGS✱SOV218-1(-0)	2EGS✱SOV218-2(-P)

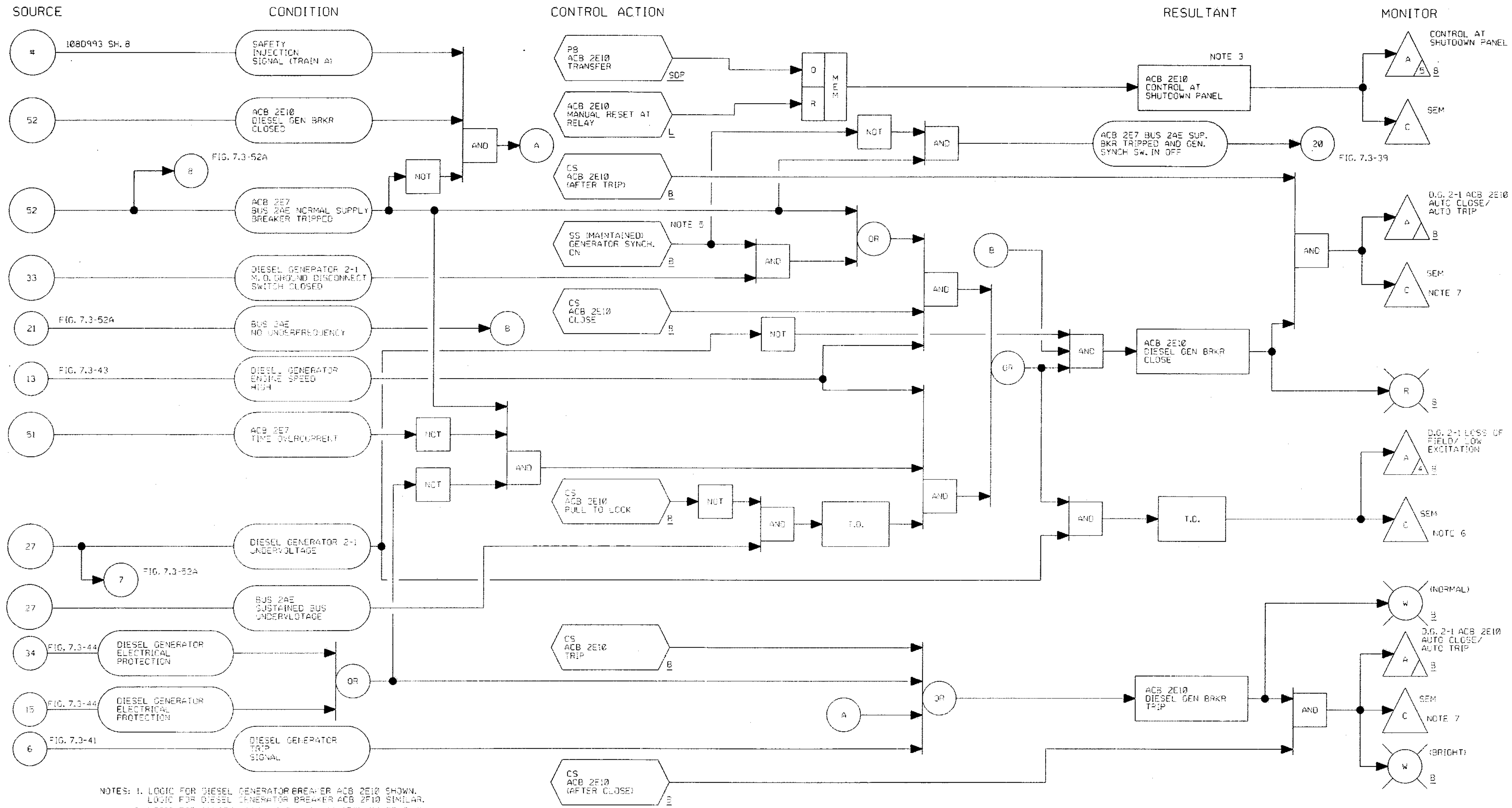
FIGURE 7.3-43
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12

NOTES:
1. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-1(-O) ELECTRICAL PROTECTION SHOWN. LOGIC FOR DIESEL GENERATOR 2EGS•EG2-2(-P) ELECTRICAL PROTECTION SIMILAR.
2. COMMON COMPUTER INPUT ALSO SHOWN ON LSK-22-6G.

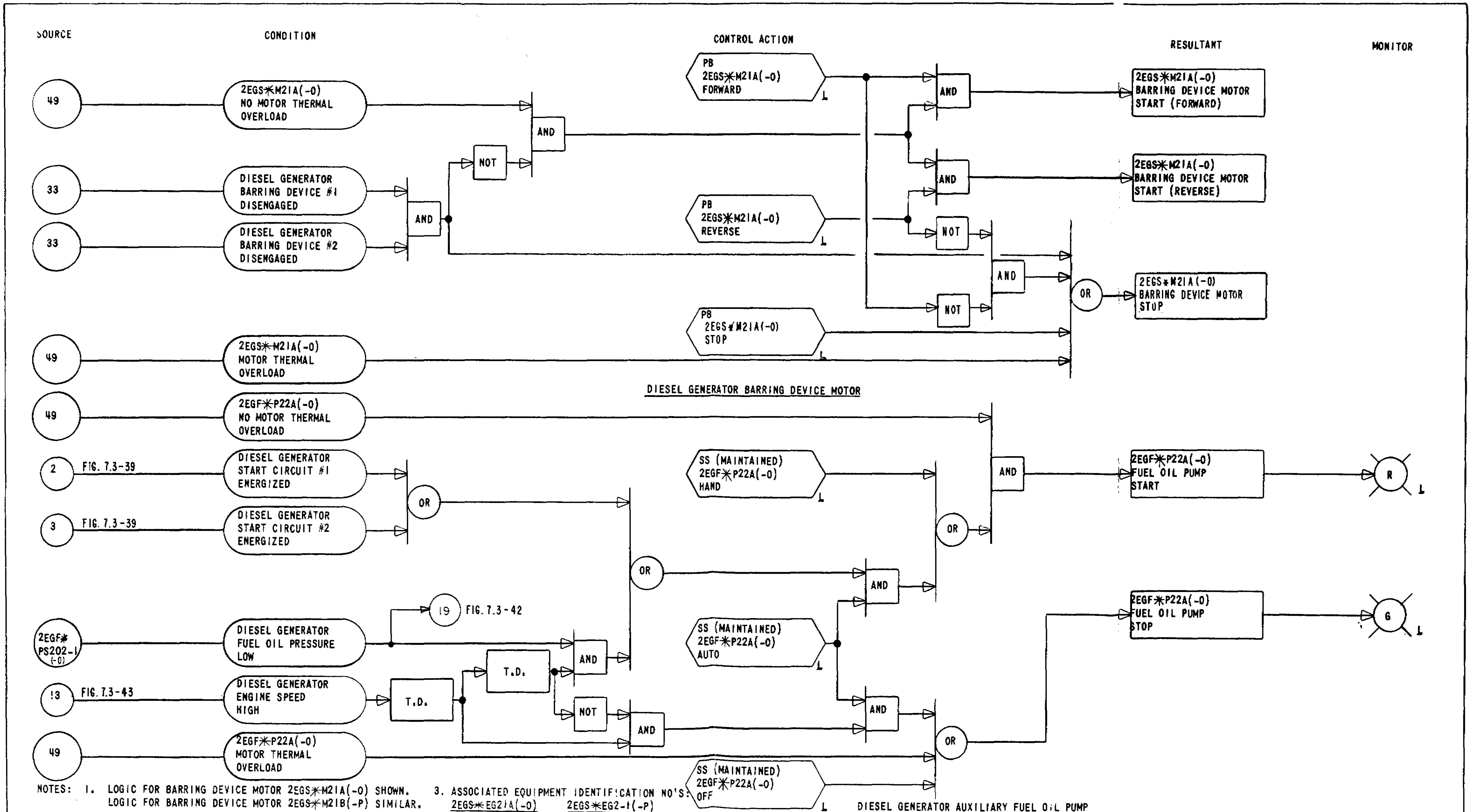
FIGURE 7.3-44
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12



NOTES:
1. LOGIC FOR DIESEL GENERATOR BREAKER ACB 2E10 SHOWN. LOGIC FOR DIESEL GENERATOR BREAKER ACB 2F10 SIMILAR.
2. LOGIC FOR CONTROL FROM THE MAIN CONTROL BOARD SHOWN. LOGIC FOR CONTROL FROM THE SHUTDOWN PANEL SIMILAR.
3. CONTROL FROM THE MAIN CONTROL BOARD IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER RELAY HAS BEEN RESET AND FROM THE SHUTDOWN PANEL WHEN IT HAS BEEN ACTUATED.
4. LOGIC FOR ACB 2E10 ALSO SHOWN ON LSK-22-6D.
5. GENERATOR SYNCH. SWITCH NOT PROVIDED ON SHUTDOWN PANEL.
6. COMMON COMPUTER INPUT ALSO SHOWN ON LSK-22-6F.
7. ONE COMPUTER INPUT DENOTES BOTH ON/OFF INDICATION.
8. * BY WESTINGHOUSE.

FIGURE 7.3-45
LOGIC DIAGRAM
EMERGENCY GENERATOR - STARTING
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

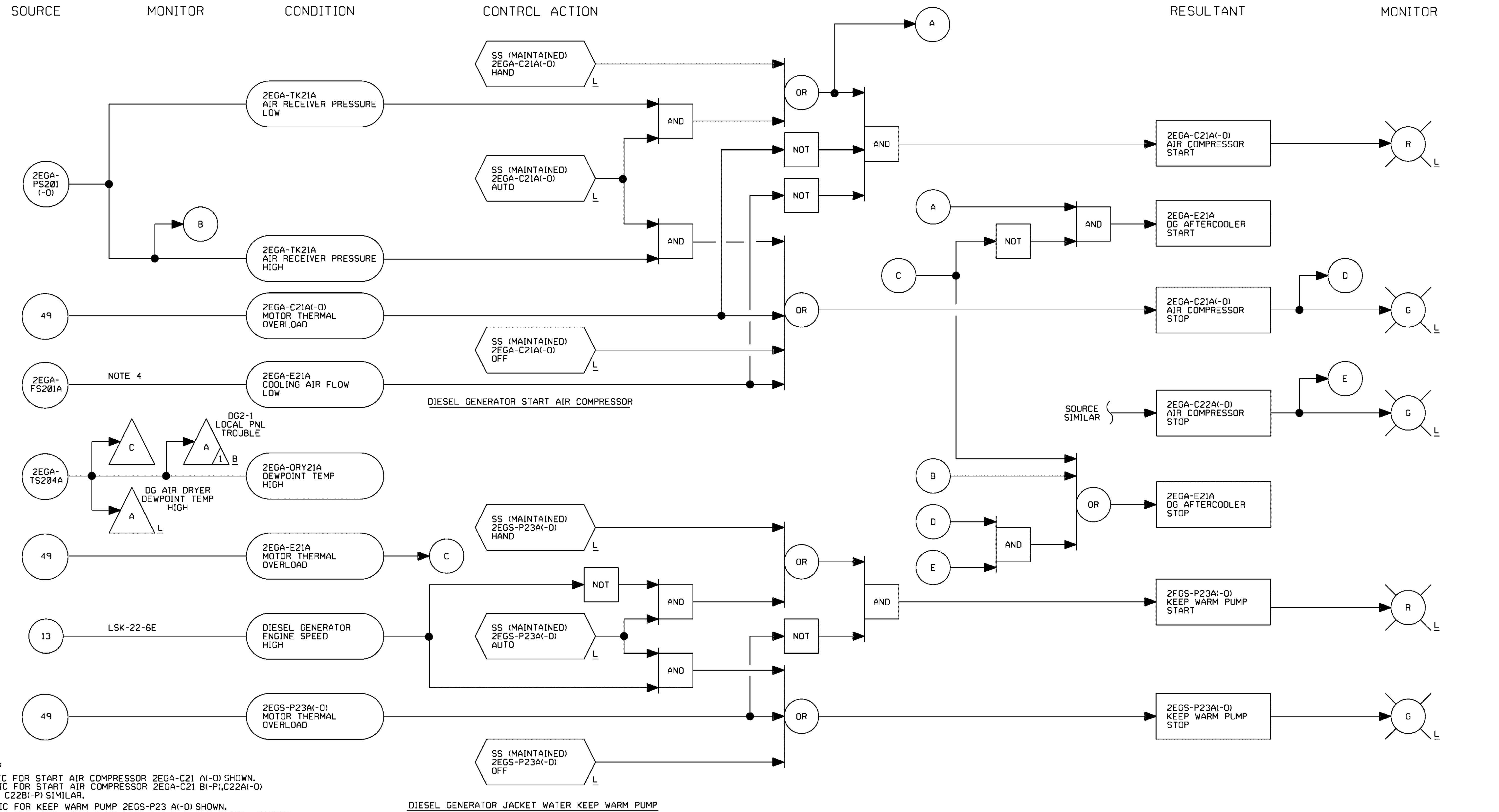


NOTES:

1. LOGIC FOR BARRING DEVICE MOTOR 2EGS✱M21A(-0) SHOWN.
   LOGIC FOR BARRING DEVICE MOTOR 2EGS✱M21B(-P) SIMILAR.
2. LOGIC FOR FUEL OIL PUMP 2EGF✱P22A(-0) SHOWN.
   LOGIC FOR FUEL OIL PUMP 2EGF✱P22B(-P) SIMILAR.
3. ASSOCIATED EQUIPMENT IDENTIFICATION NO'S:

2EGS✱EG2-1(-0)	2EGS✱EG2-1(-P)
2EGS✱M21A(-0)	2EGS✱M21B(-P)
2EGF✱PS202-1(-0)	2EGF✱PS202-2(-P)
2EGF✱P22A(-0)	2EGF✱P22B(-P)

FIGURE 7.3-46
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



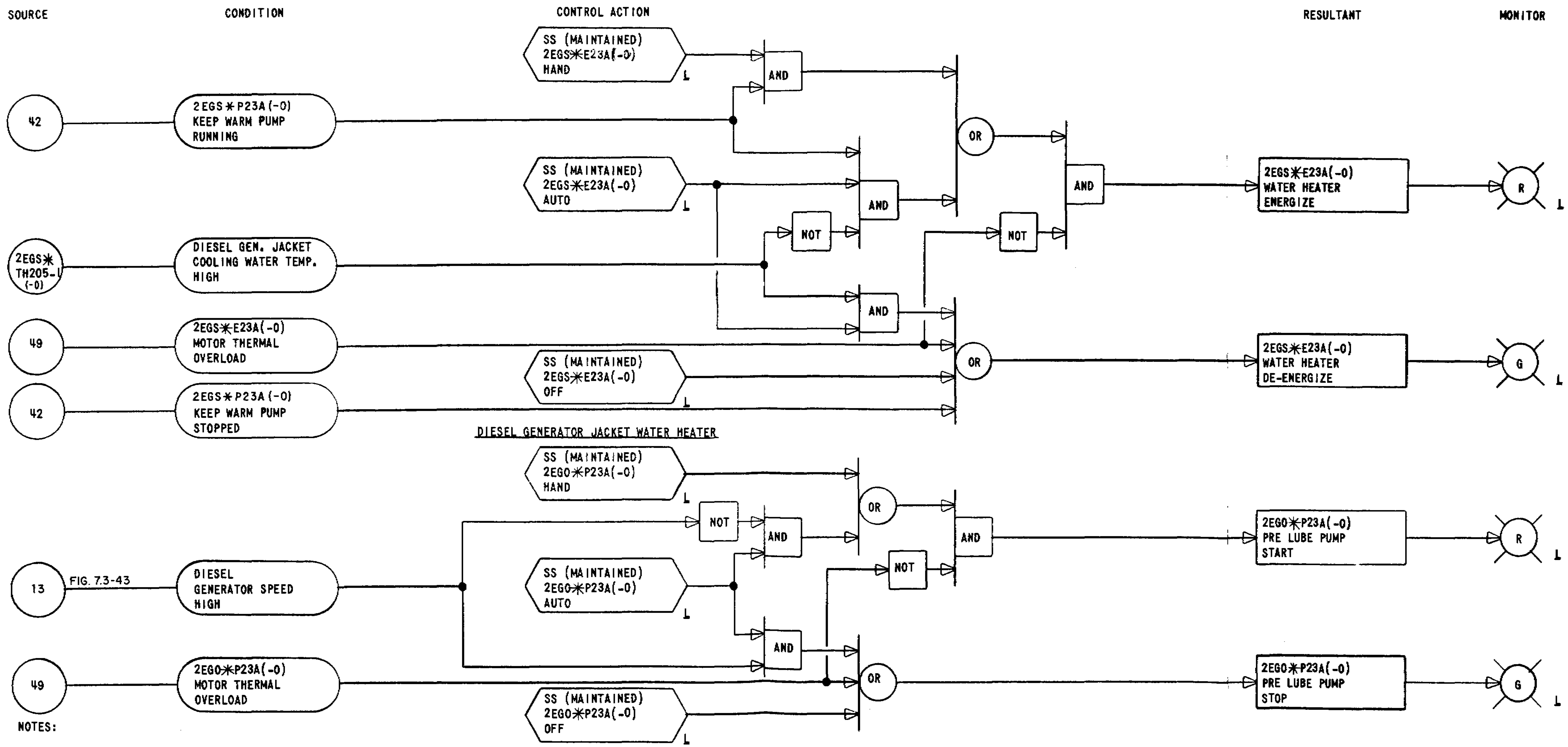
NOTES:

1. LOGIC FOR START AIR COMPRESSOR 2EGA-C21 A(-O) SHOWN. LOGIC FOR START AIR COMPRESSOR 2EGA-C21 B(-P),C22A(-O) AND C22B(-P) SIMILAR.
2. LOGIC FOR KEEP WARM PUMP 2EGS-P23 A(-O) SHOWN. LOGIC FOR KEEP WARM PUMP 2EGS-P23 B(-B) AND SPACE HEATERS 2EGS-H21A(-O) AND H21B(-P) SIMILAR.
3. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS- EG2-1(-O)	2EGS- EG2-2(-P)	2EGS- EG2-1(-O)	2EGS- EG2-2(-P)
2EGA- C21A(-O)	2EGA- C21B(-P)	2EGS- P23A(-O)	2EGS- P23B(-P)
2EGA- TK21A	2EGA- TK21B	2EGS-H21A(-O)	2EGS- H21B(-P)
2EGA- PS201(-O)	2EGA- PS202(-P)	2EGA-E21A	2EGA- E21B
2EGA- C22A(-O)	2EGA- C22B(-P)	2EGA-FS201A	2EGA- FS201B
2EGA- TK22A	2EGA- TK22B	2EGA-TS204A	2EGA- TS204B
2EGA- PS203(-O)	2EGA- PS204(-P)		

4. LOCAL TOGGLE SWITCH IS PROVIDED FOR BYPASS OF 2EGA-FS201A AND FS201B FOR OPERATION OF COMPRESSORS WHEN AIR DRYING EQUIPMENT IS NOT OPERATING.

FIGURE 7.3-47
LOGIC DIAGRAM
EMERGENCY GENERATOR - STARTING
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

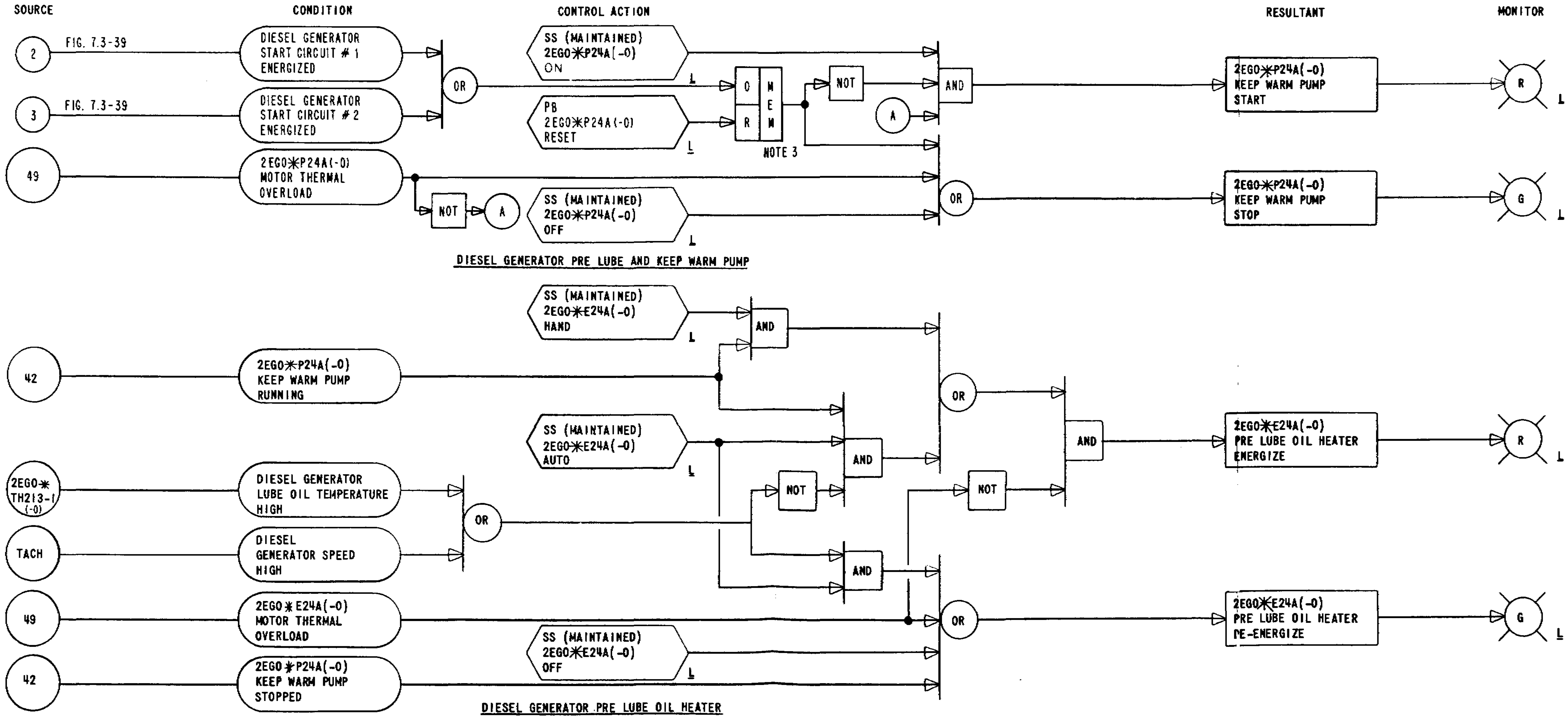
1. LOGIC FOR JACKET WATER HEATER 2EGS✱E23A(-0) SHOWN.
   LOGIC FOR JACKET WATER HEATER 2EGS✱E23B(-P) SIMILAR.
2. LOGIC FOR ROCKER ARM PRE LUBE PUMP 2EGO✱P23A(-0) SHOWN.
   LOGIC FOR ROCKER ARM PRE LUBE PUMP 2EGO✱P23B(-P).

DIESEL GENERATOR ROCKER ARM PRE LUBE PUMP

3. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS✱EG2-1(-0)	2EGS✱EG2-2(-P)
2EGS✱E23A(-0)	2EGS✱E23B(-P)
2EGS✱TH205-1(-0)	2EGS✱TH205-2(-P)
2EGO✱P23A(-0)	2EGO✱P23B(-P)
2EDG✱P21A(-0)	2EDG✱P21B(-P)

FIGURE 7.3-48
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

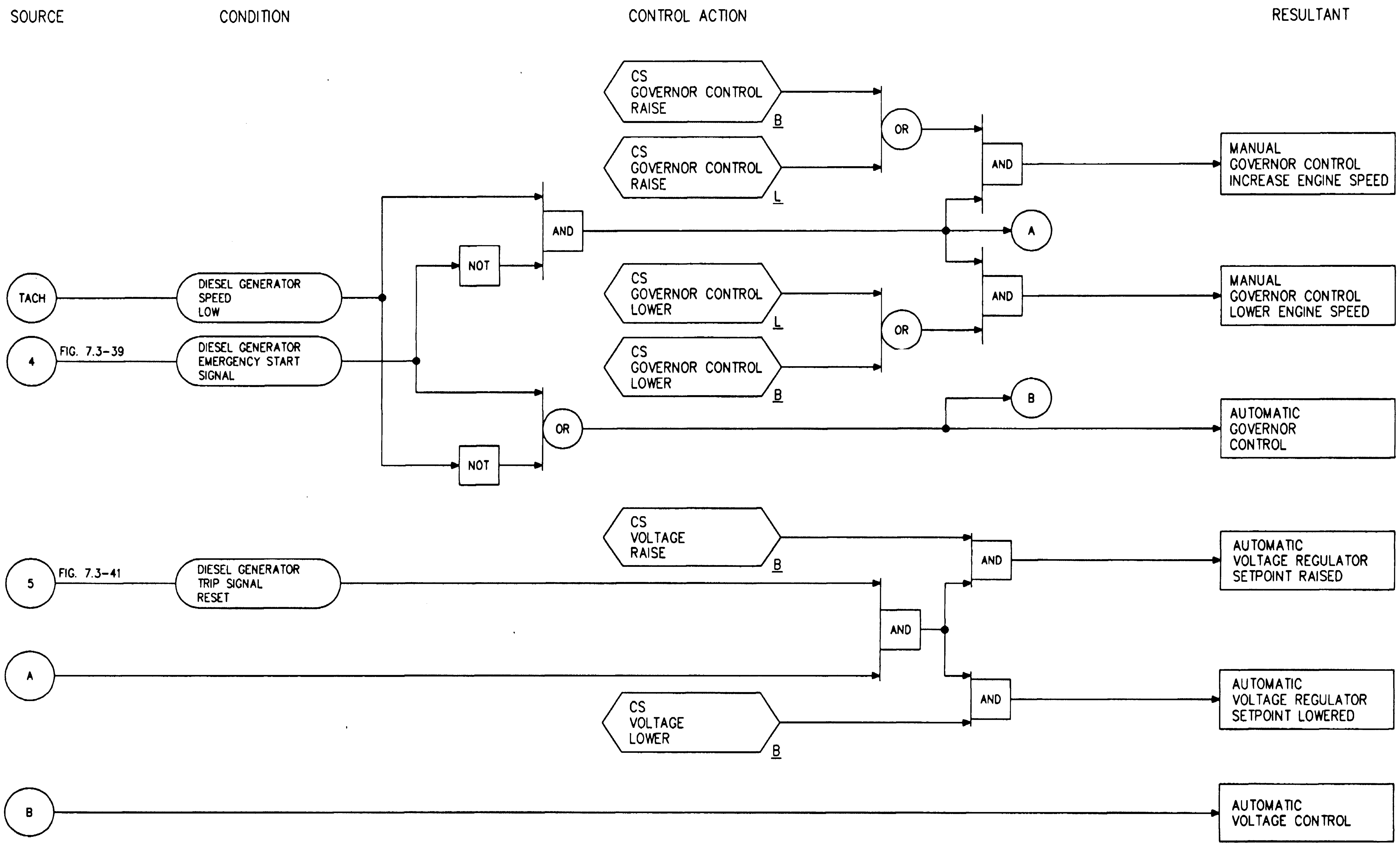


NOTES:
1. LOGIC FOR PRELUBE OIL AND KEEP WARM PUMP 2EGO✱P24A(-0) SHOWN.
   LOGIC FOR PRELUBE OIL AND KEEP WARM PUMP 2EGO✱P24B(-P) SIMILAR.
2. LOGIC FOR PRELUBE OIL HEATER 2EGO✱E24A(-0) SHOWN.
   LOGIC FOR PRELUBE OIL HEATER 2EGO✱E24B(-P) SIMILAR.
3. REPRESENTS SHUNT TRIP.
4. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS✱EG2-1(-0)	2EGS✱EG2-2(-P)
2EGO✱P24A(-0)	2EGO✱P24B(-P)
2EGO✱E24A(-0)	2EGO✱E24B(-P)
2EGS✱TH213-1(-0)	2EGS✱TH213-2(-P)

FIGURE 7.3-49
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 16



NOTES:

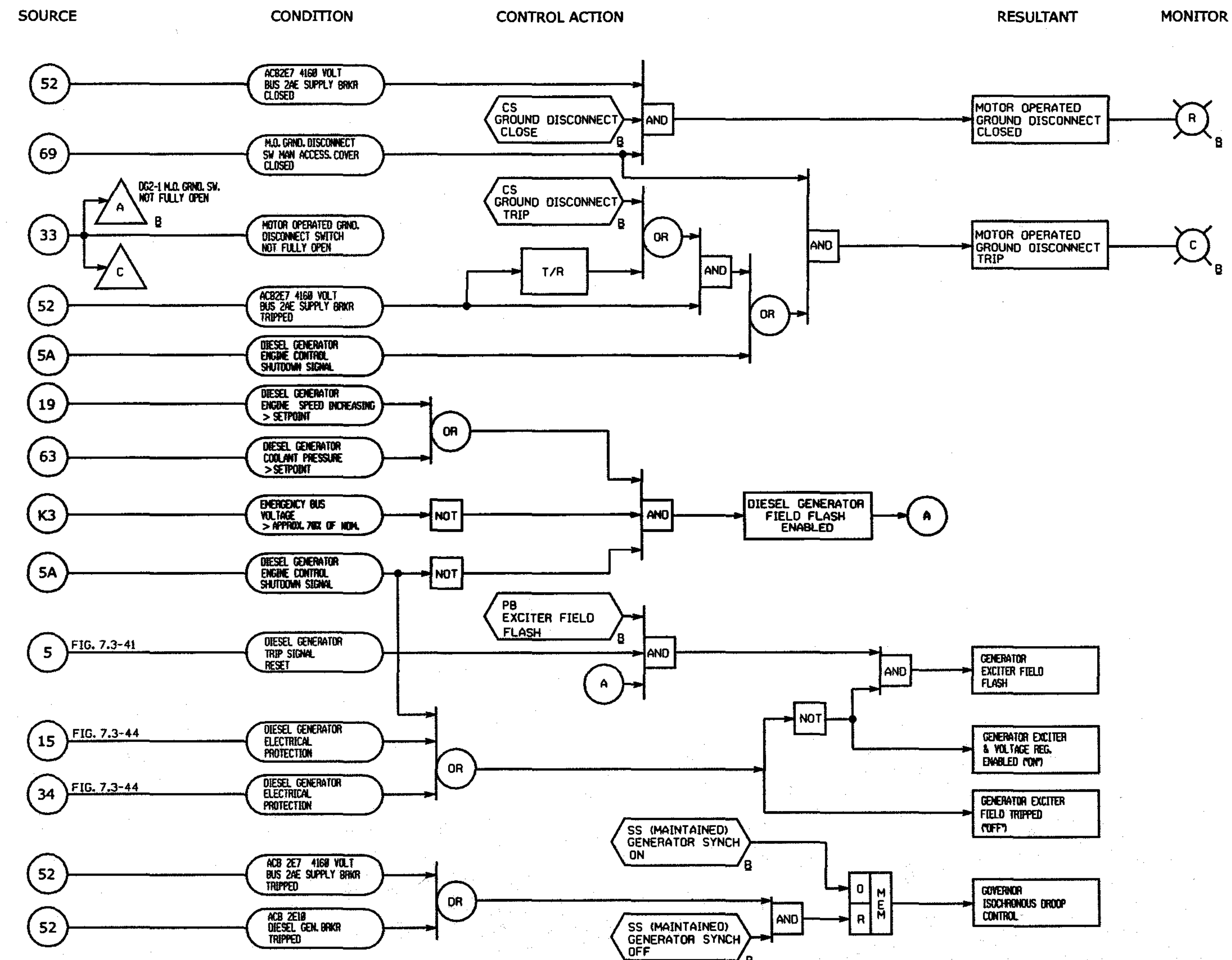
1. LOGIC SHOWN FOR DIESEL GENERATOR 2EGS*DG2-1(-O) SHOWN. DIESEL GENERATOR 2EGS-DG2*2(-P) SIMILAR.

FIGURE 7.3-50

LOGIC DIAGRAM
EMERGENCY GENERATOR - STARTING

BEAVER VALLEY POWER STATIION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 17



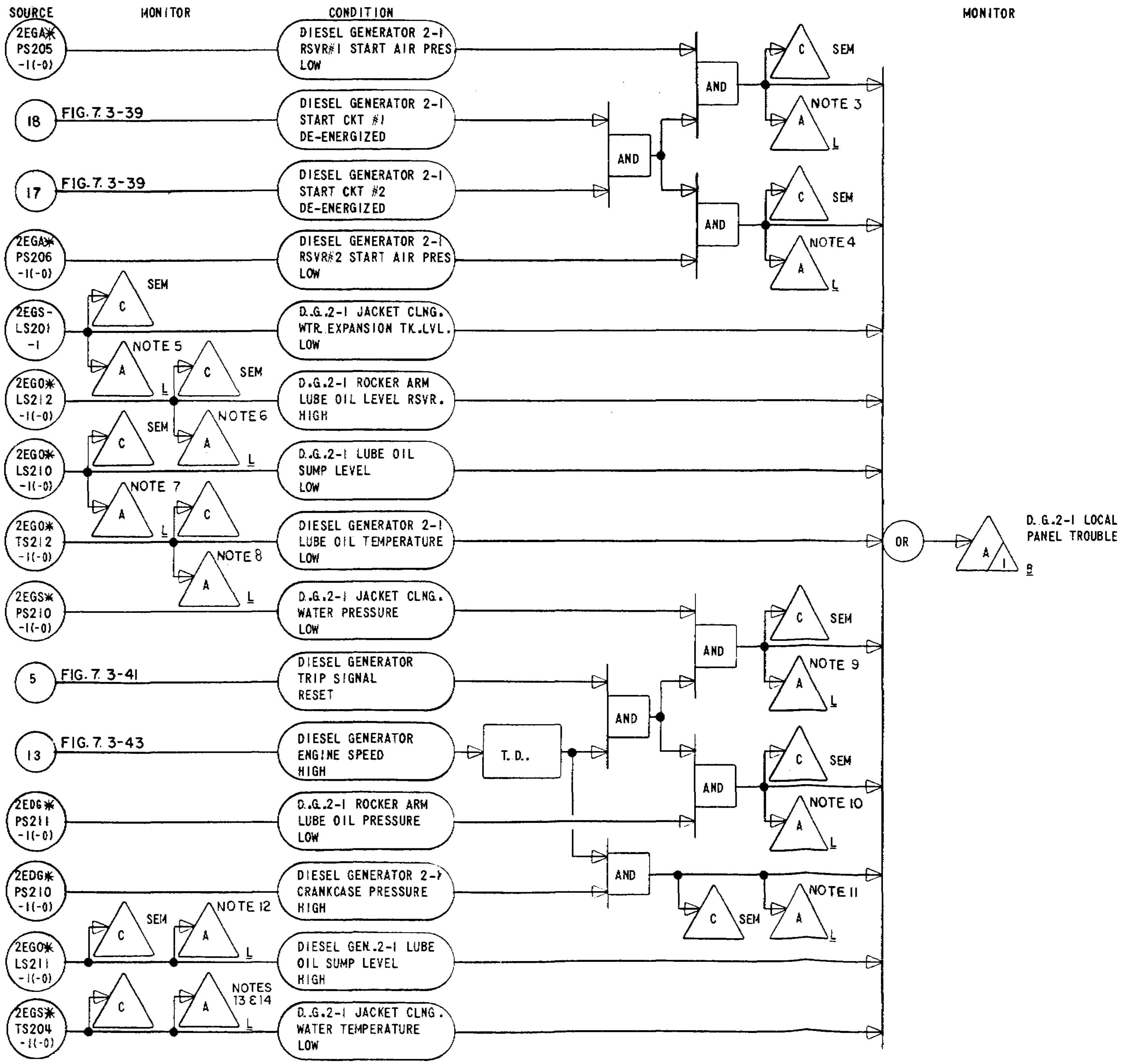
NOTES:

1. LOGIC SHOWN FOR DIESEL GENERATOR 2EGS*DG2-1(-O) SHOWN. DIESEL GENERATOR 2EGS*DG2-2(-P) SIMILAR
2. INITIATION OF ISOCHRONOUS DROOP CONTROL PERMITS SLOW LOADING OF DIESEL GENERATOR DURING THE EXERCISE MODE OF OPERATION INSTEAD OF THE NORMAL FAST LOAD CAPABILITIES.
3. REFER TO FIGURE 7.3-44 FOR LOGIC DEVELOPMENT OF DIESEL GENERATOR ELECTRICAL PROTECTION.

FIGURE 7.3-51

LOGIC DIAGRAM
EMERGENCY GENERATOR - STARTING

BEAVER VALLEY POWER STATIION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

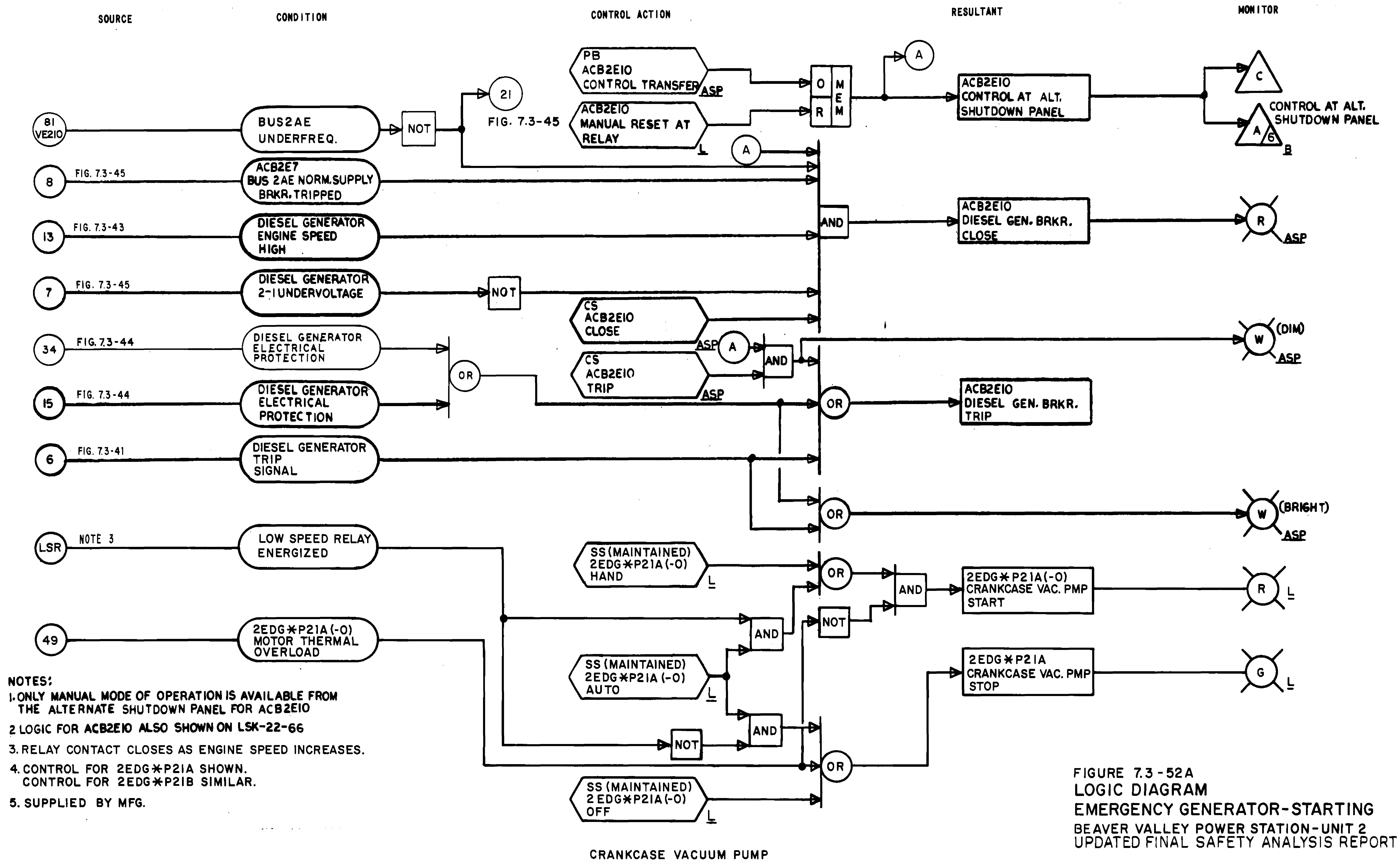
1. LOGIC FOR DIESEL GENERATOR 2-1 SHOWN. LOGIC FOR DIESEL GENERATOR 2-2 SIMILAR.
2. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

2EGS✱EG2-1(-0)	2EGS✱EG2-2(-P)
2EGA✱PS205-1(-0)	2EGA✱PS205-2(-P)
2EGA✱PS206-1(-0)	2EGA✱PS206-2(-P)
2EGS-LS201-1	2EGS-LS201-2
2EGO✱LS212-1(-0)	2EGO✱LS212-2(-P)
2EGO✱LS210-1(-0)	2EGO✱LS210-2(-P)
2EGO✱TS212-1(-0)	2EGO✱TS212-2(-P)
2EGS✱PS210-1(-0)	2EGS✱PS210-2(-P)
2EGO✱PS211-1(-0)	2EGO✱PS211-2(-P)
2EDG✱PS210-1(-0)	2EDG✱PS210-2(-P)
2EDG✱LS211-1(-0)	2EDG✱LS211-2(-P)
2EGS✱TS204-1(-0)	2EGS✱TS204-2(-P)

3. DG 2-1 RECIEVER #1 AIR PRESSURE LOW
4. DG 2-1 RECIEVER #2 AIR PRESSURE LOW
5. DG 2-1 JACKET CLNG. WTR. EXPANSION TK. LVL. LOW
6. DG 2-1 ROCKER ARM LUBE OIL RSVR HIGH
7. DG 2-1 LUBE OIL SUMP LEVEL LOW
8. DG 2-1 LUBE OIL TEMP. LOW
9. DG 2-1 JACKET COOLING WATER PRESSURE LOW
10. DG 2-1 ROCKER ARM LUBE OIL PRESSURE LOW
11. DG 2-1 CRANKCASE PRESSURE HIGH
12. DG 2-1 LUBE OIL SUMP LEVEL HIGH
13. DG 2-1 JACKET COOLING WATER TEMP. LOW
14. THIS ALARM IS CUTOUT WHEN LOW SPEED RELAY (LSR) IS ENERGIZED.

FIGURE 7.3-52
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12

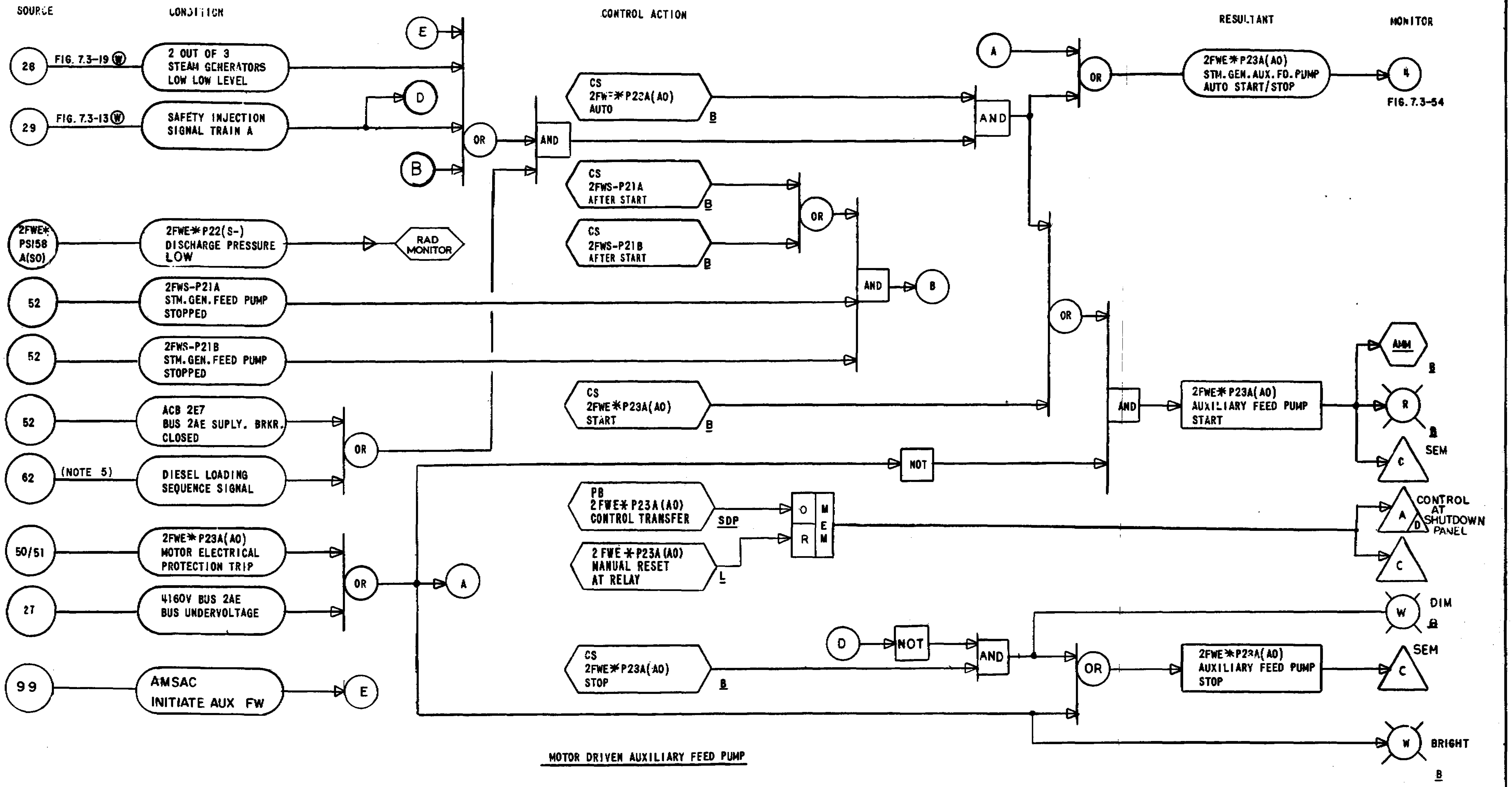


NOTES:

1. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL FOR ACB2EIO
2. LOGIC FOR ACB2EIO ALSO SHOWN ON LSK-22-66
3. RELAY CONTACT CLOSES AS ENGINE SPEED INCREASES.
4. CONTROL FOR 2EDG✱P21A SHOWN. CONTROL FOR 2EDG✱P21B SIMILAR.
5. SUPPLIED BY MFG.

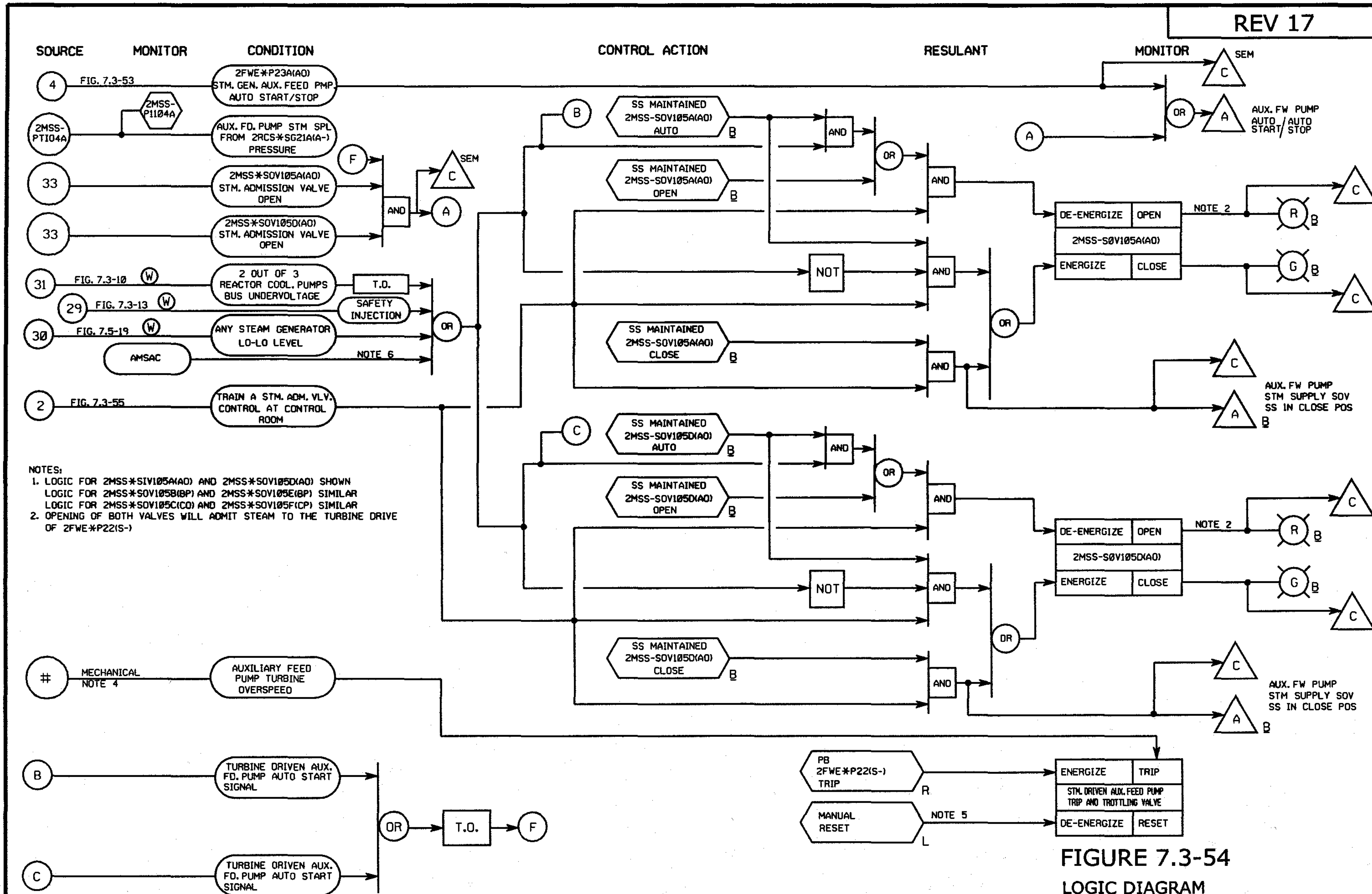
FIGURE 7.3-52A
LOGIC DIAGRAM
EMERGENCY GENERATOR-STARTING
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV.10 (97)



1. # WESTINGHOUSE FUNCTIONAL DRAWINGS.
2. CONTROL FROM CONTROL ROOM SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR.
3. LOGIC FOR 2FWE*P23A(AO) SHOWN LOGIC FOR 2FWE*P23B(BP) SIMILAR
4. SEE ADDITIONAL CONTROL OF 2FWE*P23A(AO) ON FIG.7.3-56A
5. DIESEL LOADING SEQUENCE SIGNAL WILL BE RETAINED FOR 5 SECONDS THEN BLOCKED UNTIL THE SEQUENCER CYCLE HAS BEEN COMPLETED

FIGURE 7.3-53
LOGIC DIAGRAM
STEAM GENERATOR AUXILIARY FEED PUMPS & VALVES
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR 2MSS*SIV105A(AO) AND 2MSS*SOV105D(AO) SHOWN
   LOGIC FOR 2MSS*SOV105B(BP) AND 2MSS*SOV105E(BP) SIMILAR
   LOGIC FOR 2MSS*SOV105C(CO) AND 2MSS*SOV105F(CP) SIMILAR
2. OPENING OF BOTH VALVES WILL ADMIT STEAM TO THE TURBINE DRIVE OF 2FWE*P22(S-)
3. # WESTINGHOUSE FUNCTIONAL DRAWINGS
4. SUPPLIED BY MFG.
5. VALVE MUST BE MANUALLY OPENED AND LATCHED AT THE PUMP.
6. FOR VALVES 2MSS*SOV105A & D ONLY.

FIGURE 7.3-54

LOGIC DIAGRAM STEAM GENERATOR AUXILIARY FEED PUMPS AND VALVES

BEAVER VALLEY POWER STATIION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

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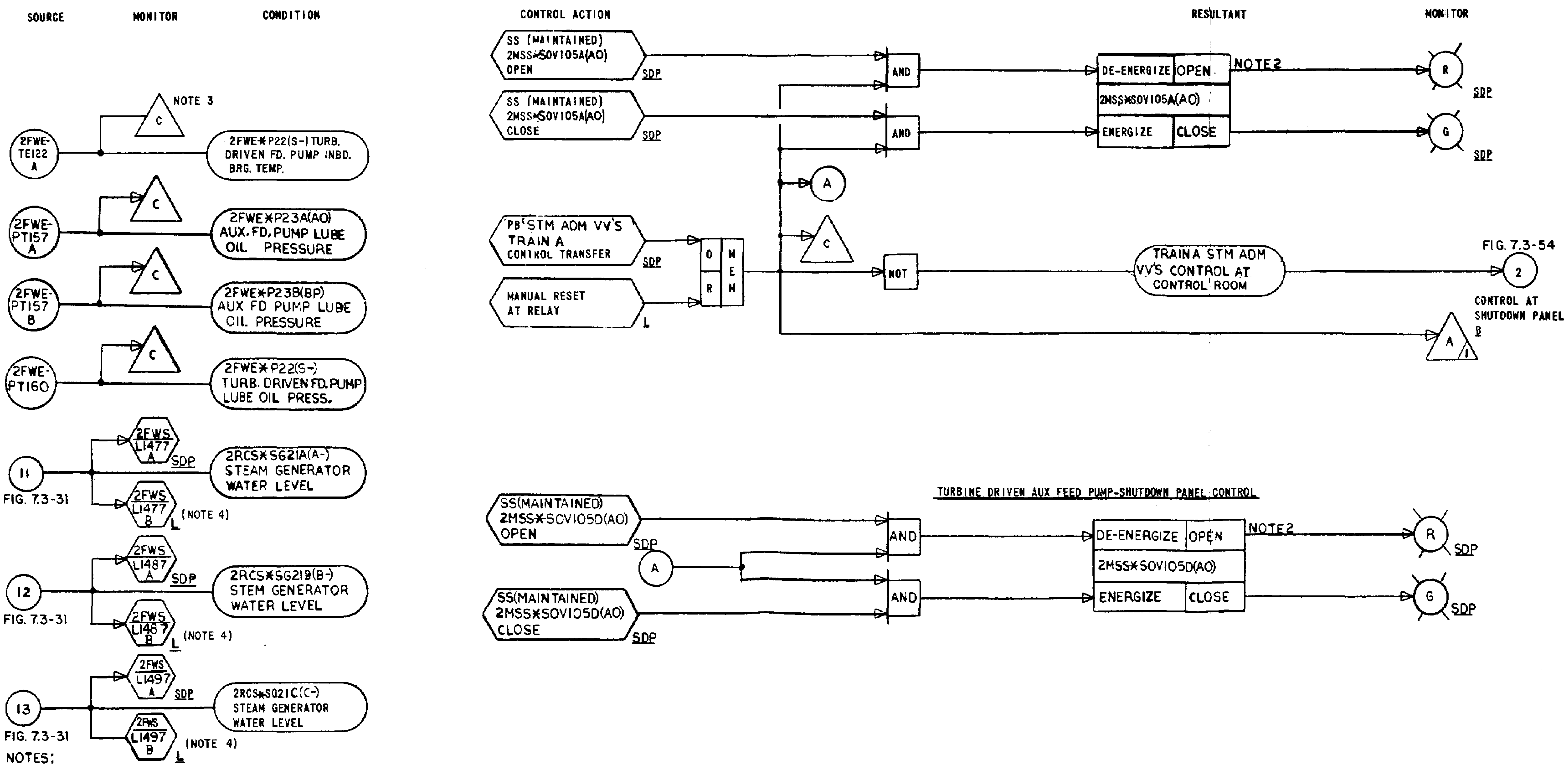
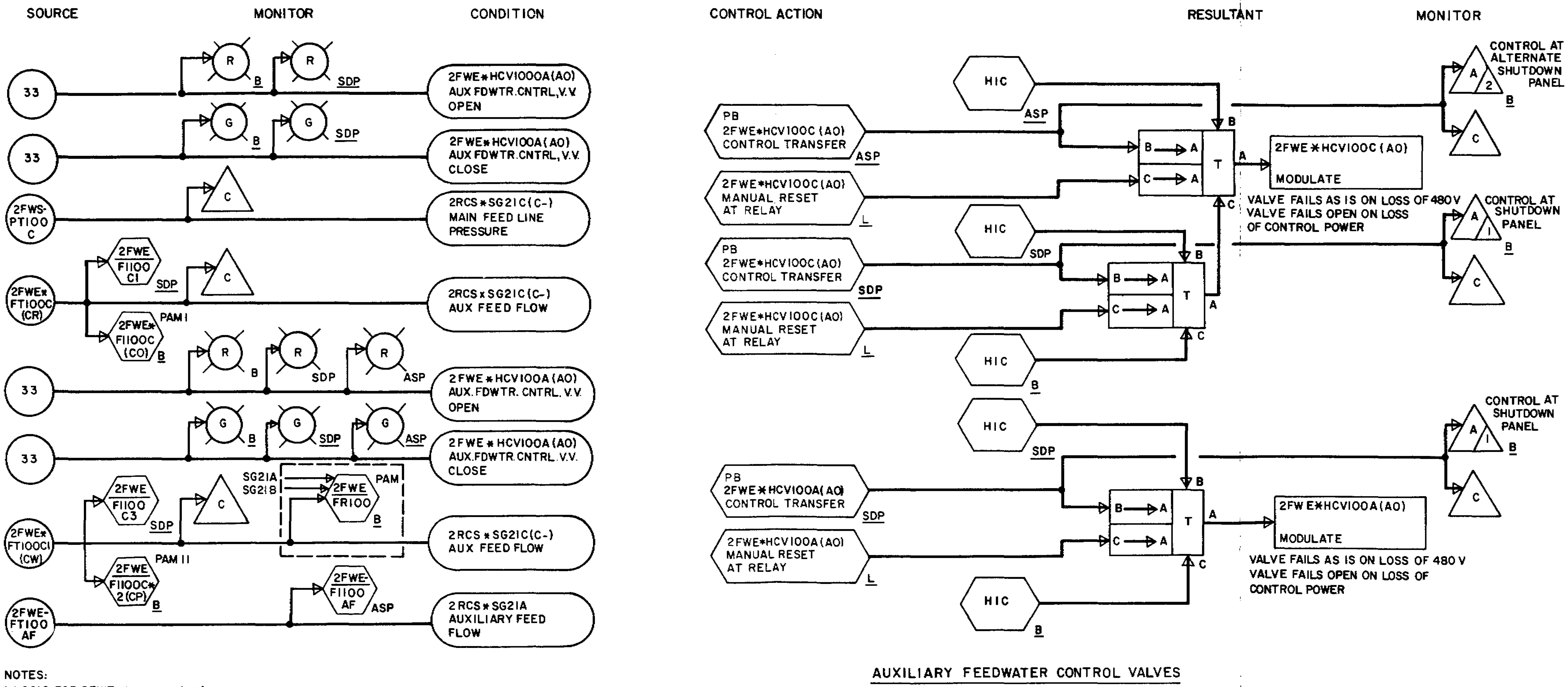


NOTES:

1. LOGIC FOR 2MSS*SOV105A(AO) AND 2MSS*SOV105D(AO) SHOWN
   LOGIC FOR 2MSS*SOV105B(BP) AND 2MSS*SOV105E(BP) SIMILAR
   LOGIC FOR 2MSS*SOV105C (CO) AND 2MSS*SOV105F (CP) SIMILAR
2. OPENING OF BOTH VALVES WILL ADMIT STEAM TO THE TURBINE DRIVE OF 2FWE*P22(S-)
3. LOGIC FOR 2 FWE-TE122A SHOWN, LOGIC FOR 2 FWE-TE122B TURBINE FEED PUMP OUTBOARD TEMPERATURE IS SIMILAR
4. LEVEL INDICATORS 2FWS-LI477B, 487B, AND 497B ARE LOCATED NEAR ASSOCIATED FEEDWATER CONTROL VALVES

FIGURE 7.3-55
LOGIC DIAGRAM
STEAM GENERATOR AUXILIARY
FEED PUMPS AND VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



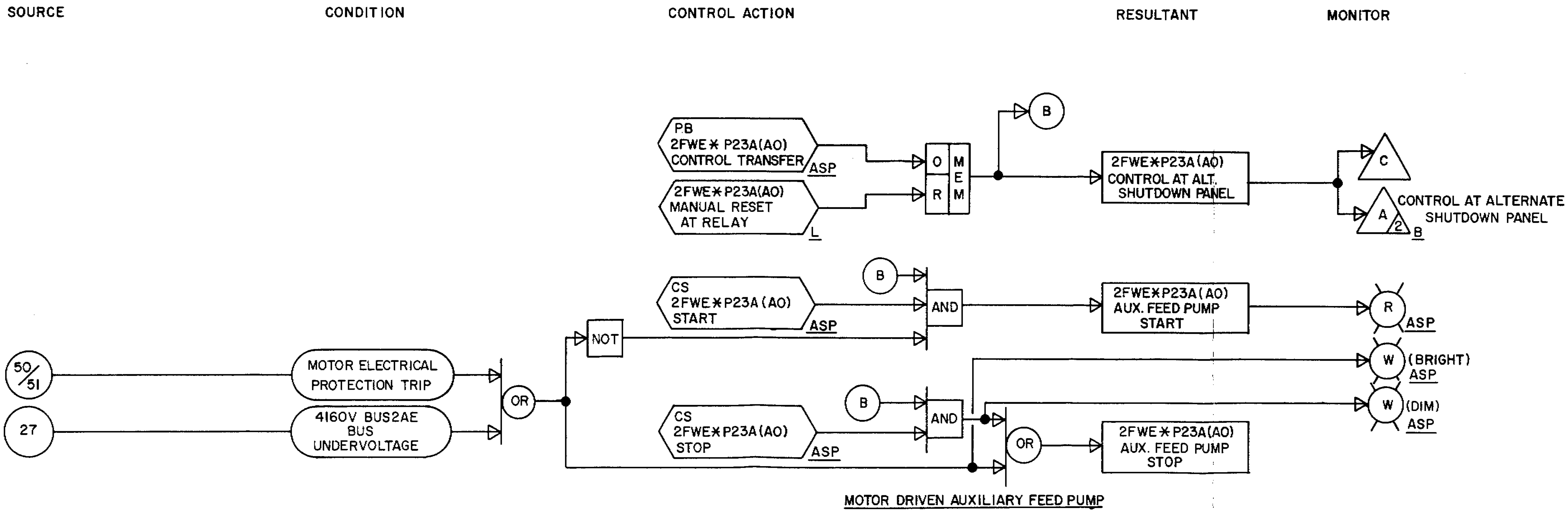
NOTES:

1. LOGIC FOR 2FWE*HCV100C(AO) SHOWN
   LOGIC FOR 2FWE*HCV100E(AO) SIMILAR.
2. LOGIC FOR 2FWE*HCV100A(AO) SHOWN
   LOGIC FOR 2FWE*HCV100B(BP), 2FWE*HCV100D(BP)
   AND 2FWE*HCV100F(BP) SIMILAR.
3. ASSOCIATED EQUIPMENT LIST

2FWE*FT100A(AR)	2FWE*FT100B(BR)	2FWE x FT100(CR) (SHOWN)
2FWE*FI100A(AO) 2FWE-FI100A1	2FWE x FI100B(BO) 2FWE-FI100B1	2FWE x FI100C(CO) 2FWE-FI100C1
2FWE*FT100A1(AW)	**2FWE*FT100B1(BW)**	**2FWE*FT100C1(CW) (SHOWN)**
2FWE*FI100A2(AP) 2FWE-FI100A3 2FWE-FR100	2FWE*FT100B2(BP) 2FWE-FI100B3 2FWE-FR100	2FWE*FI100C2(CP) 2FWE-FI100C3 2FWE-FR100

4. LOGIC FOR 2FWE-FI100AF FOR ALTERNATE SHUTDOWN PANEL SHOWN.
   LOGIC FOR 2FWE-FI100BF FOR ALTERNATE SHUTDOWN PANEL SIMILAR.

FIGURE 7.3-56
STEAM GENERATOR AUXILIARY FEED PUMPS AND VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES: 1. SEE ADDITIONAL CONTROL OF 2FWE✱P23 (AO) ON FIG. 7.3-53.
2. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.

FIGURE 7.3-56A
LOGIC DIAGRAM
STEAM GENERATOR AUXILIARY
FEED PUMPS AND VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

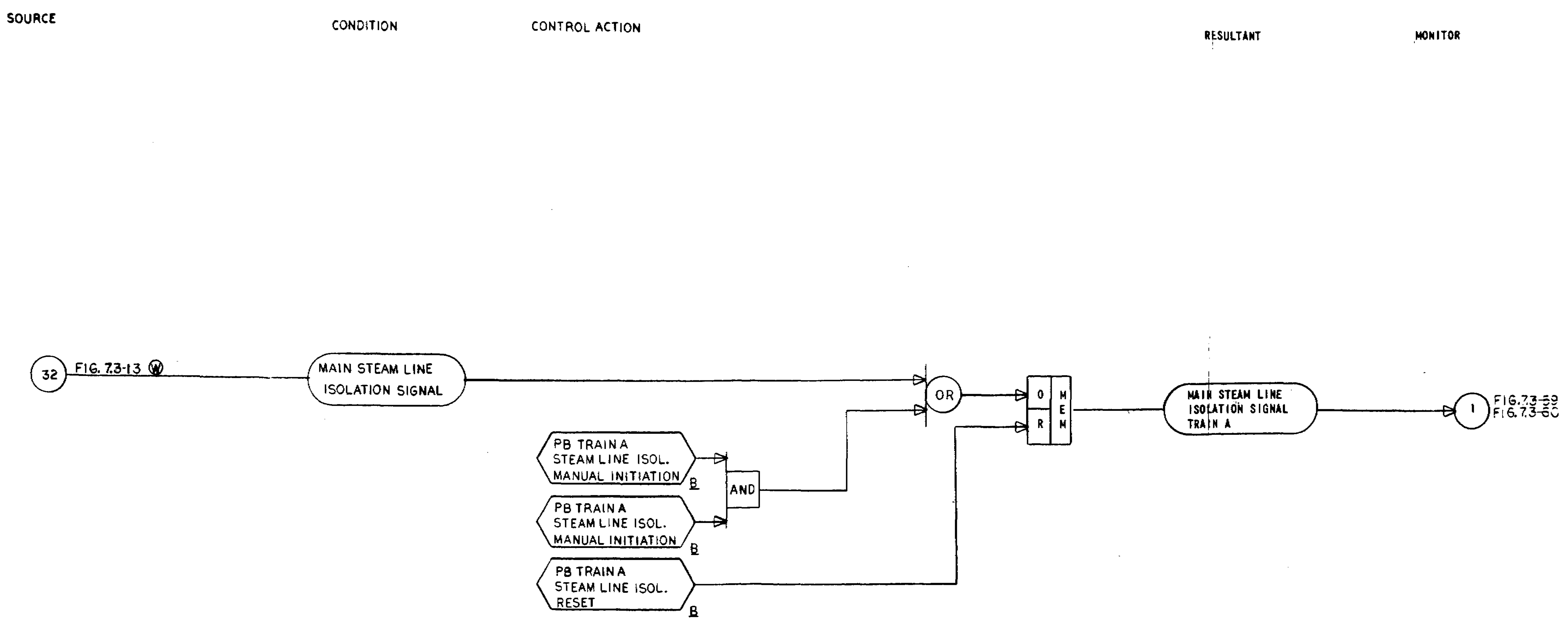


FIGURE 7.3-57
LOGIC DIAGRAM
MAIN STEAM LINE TRIP VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

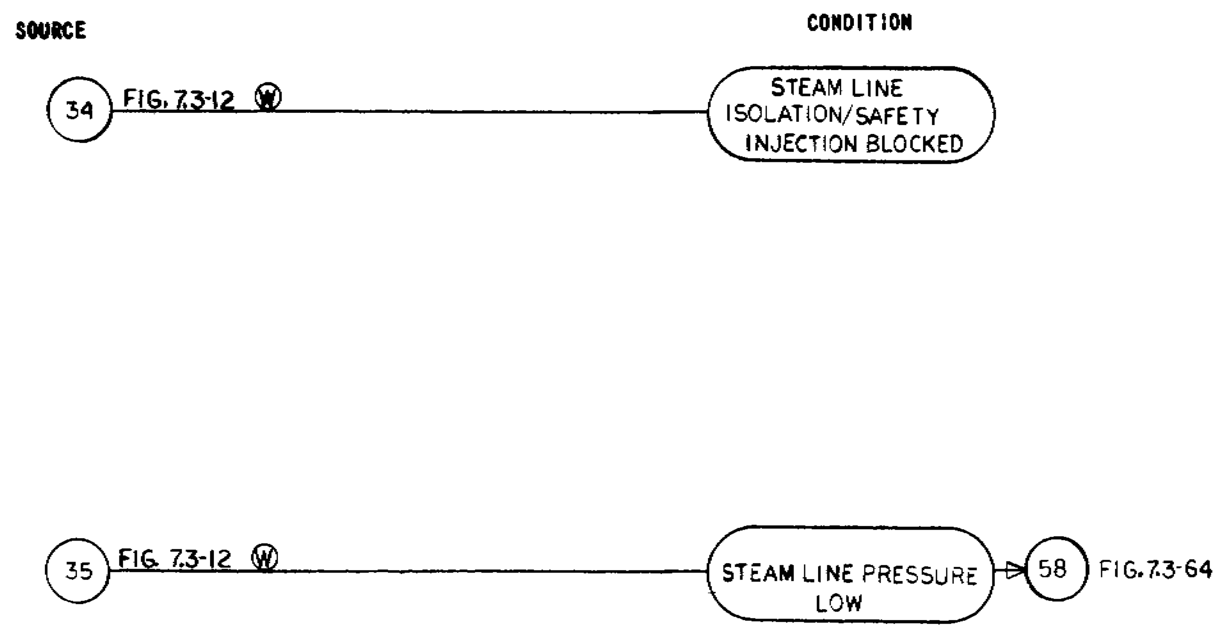
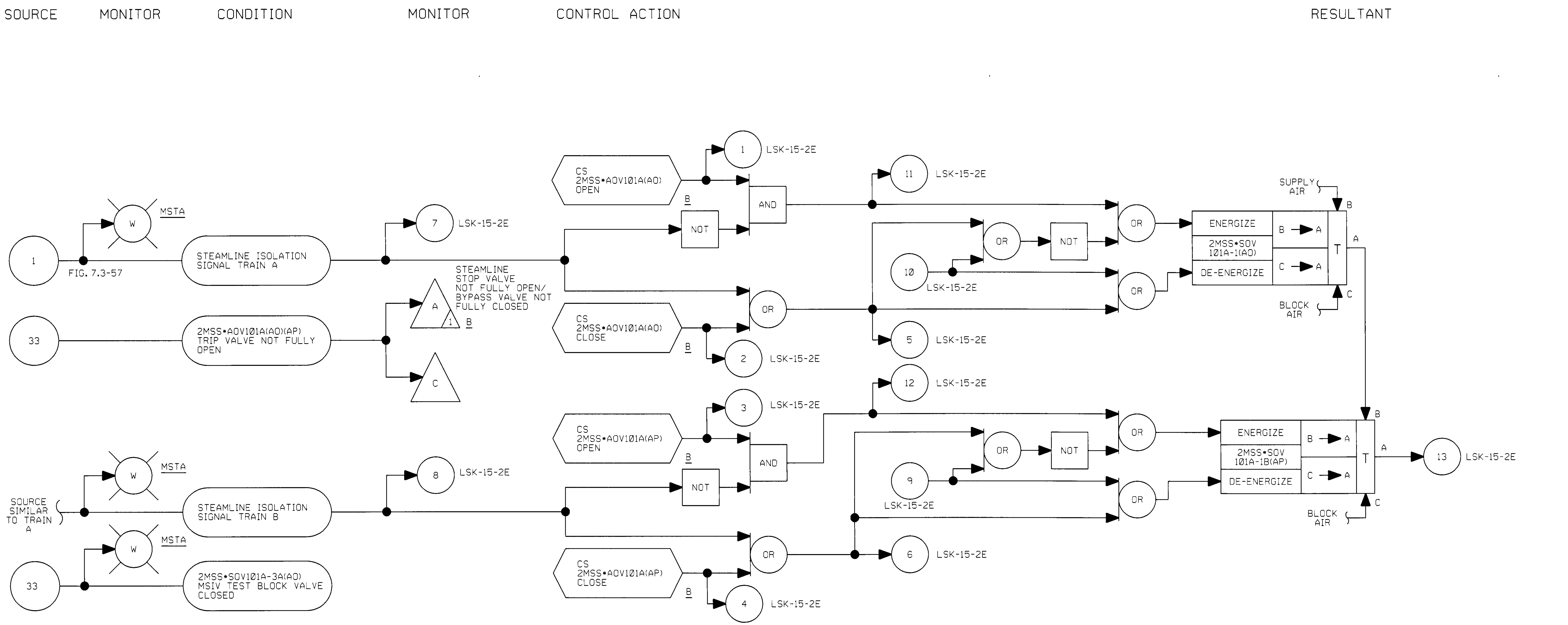


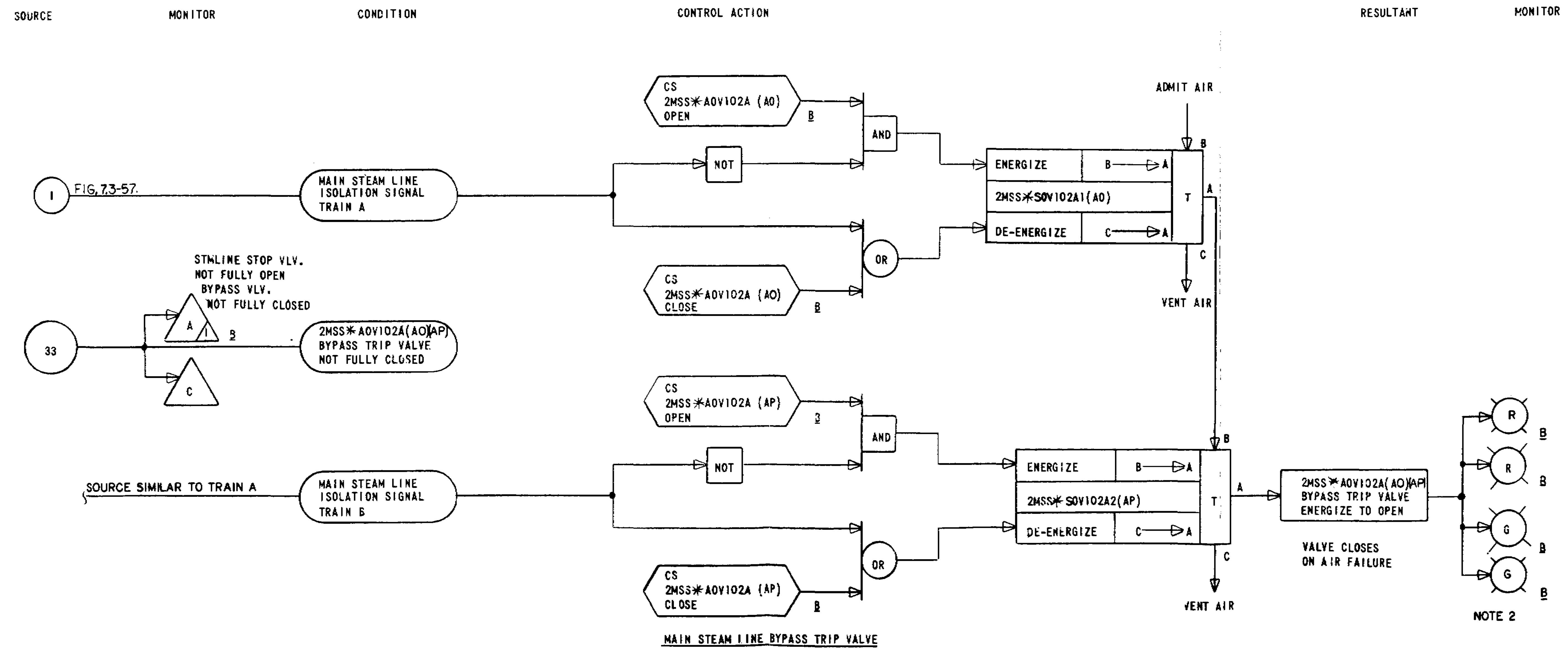
FIGURE 7.3-58
LOGIC DIAGRAM
MAIN STEAM LINE TRIP VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. CONTROL FOR 2MSS•AOV101A(AO)(AP) SHOWN. CONTROL FOR 2MSS•AOV101B(BO)(BP) AND 2MSS•AOV101C(CO)(CP) SIMILAR.
2. INPUTS FROM 2MSS•AOV101A(AO)(AP) SHOWN. INPUTS FROM 2MSS•AOV101B(BO)(BP) AND 2MSS•AOV101C(CO)(CP) SIMILAR. COMPUTER POINTS ARE PROVIDED, ONE FOR EACH VALVE.

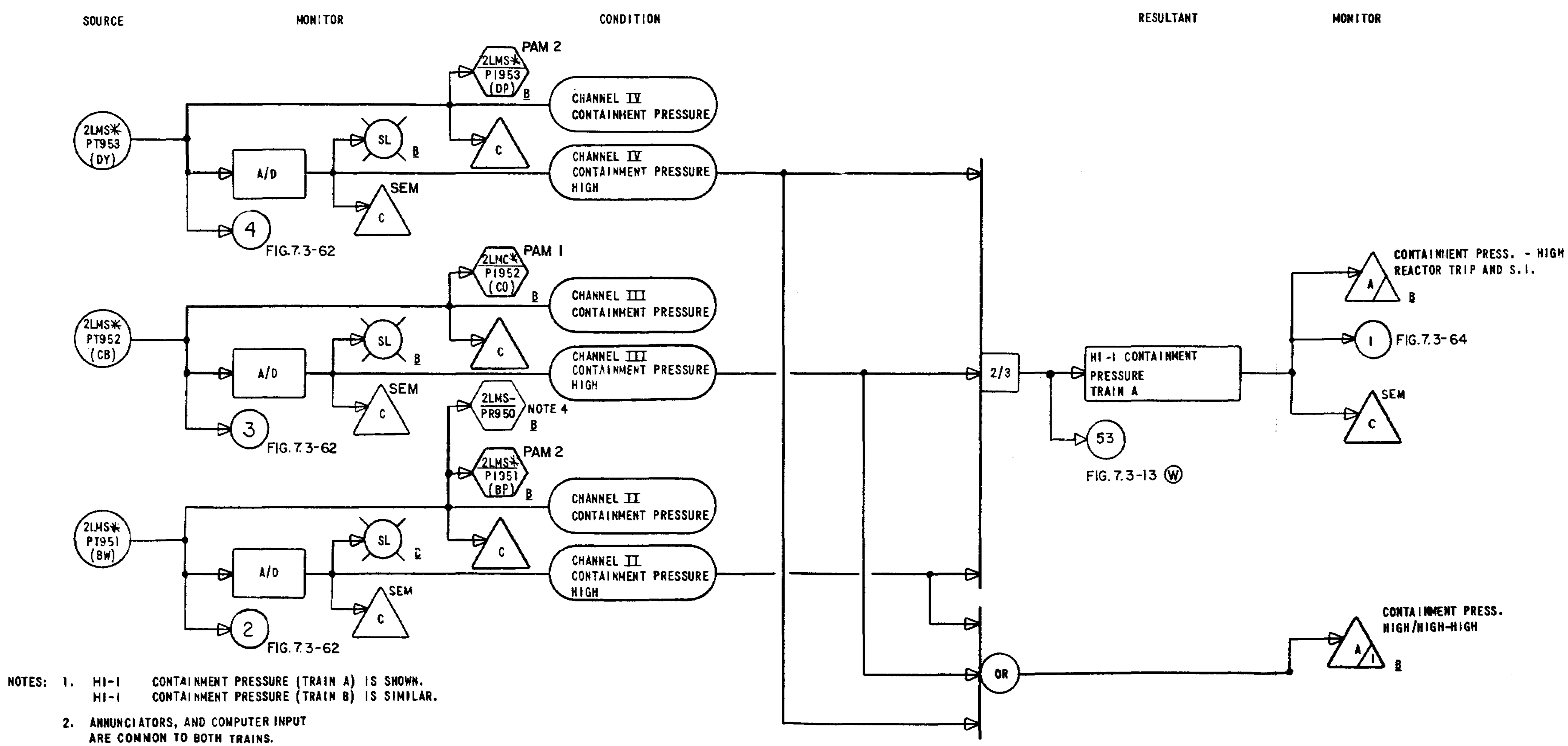
FIGURE 7.3-59
LOGIC DIAGRAM
MAIN STEAM LINE TRIP VALVES
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

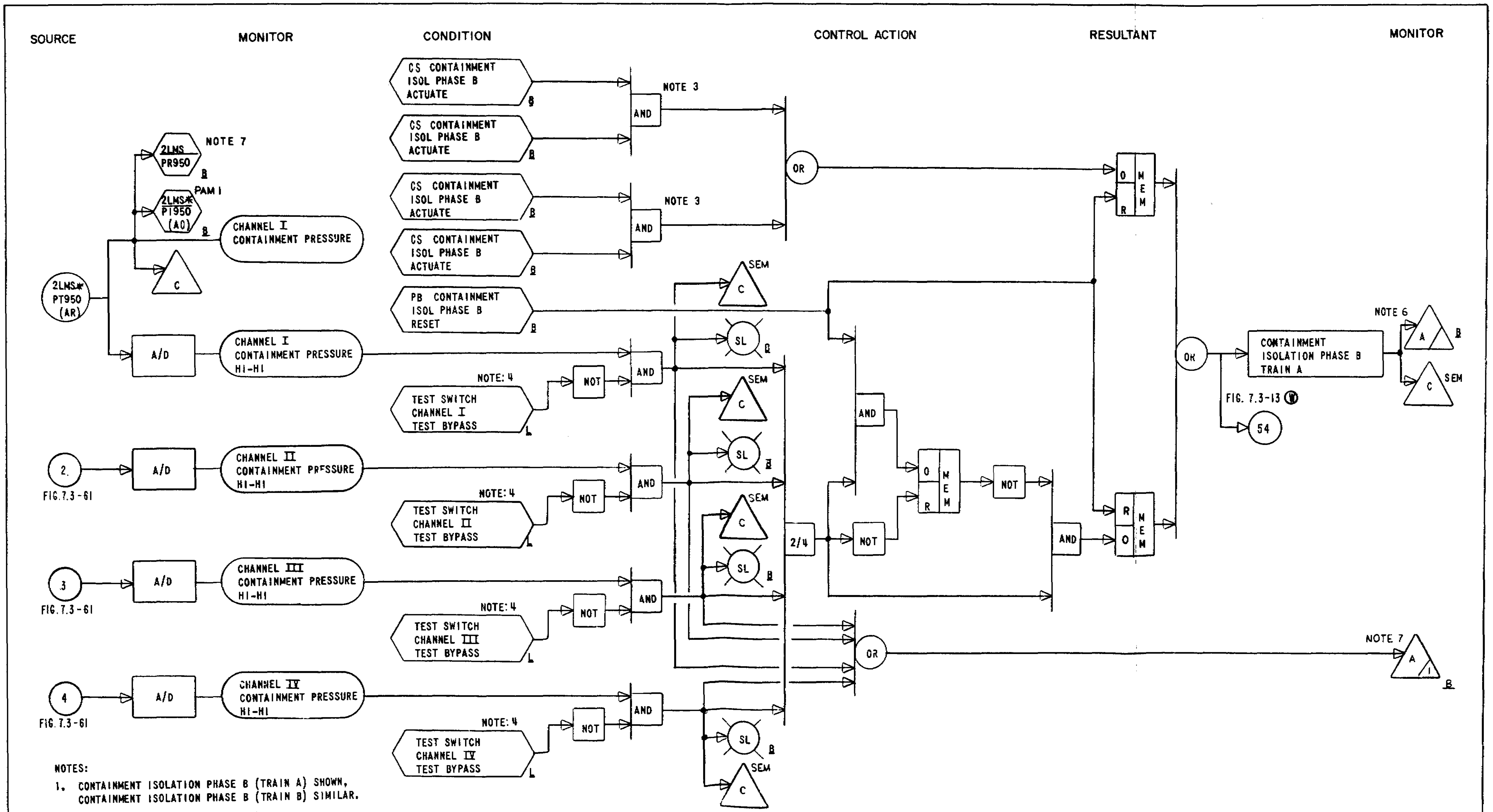
1. BYPASS TRIP VALVE 2MSS*AOV102A(AO)(AP) SHOWN, BYPASS TRIP VALVES 2MSS*AOV102B(BO)(BP) AND 102C(CO)(CP) SIMILAR.
2. TWO SWITCHES ARE PROVIDED FOR EACH BYPASS VALVE FOR INDICATION.

FIGURE 7.3-60
LOGIC DIAGRAM
MAIN STEAM LINE TRIP VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. HI-I CONTAINMENT PRESSURE (TRAIN A) IS SHOWN.
   HI-I CONTAINMENT PRESSURE (TRAIN B) IS SIMILAR.
2. ANNUNCIATORS, AND COMPUTER INPUT ARE COMMON TO BOTH TRAINS.
3. REFER TO FIG. 7.3-63 AND 64 FOR CONTAINMENT ISOLATION PHASE A AND SAFETY INJECTION.
4. 2LMS-PR950 ALSO SHOWN ON FIG. 7.3-62

FIGURE 7.3-61
LOGIC DIAGRAM-CONTAINMENT DEPRESSURIZATION AND ISOLATION SIGNAL INITIATION SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

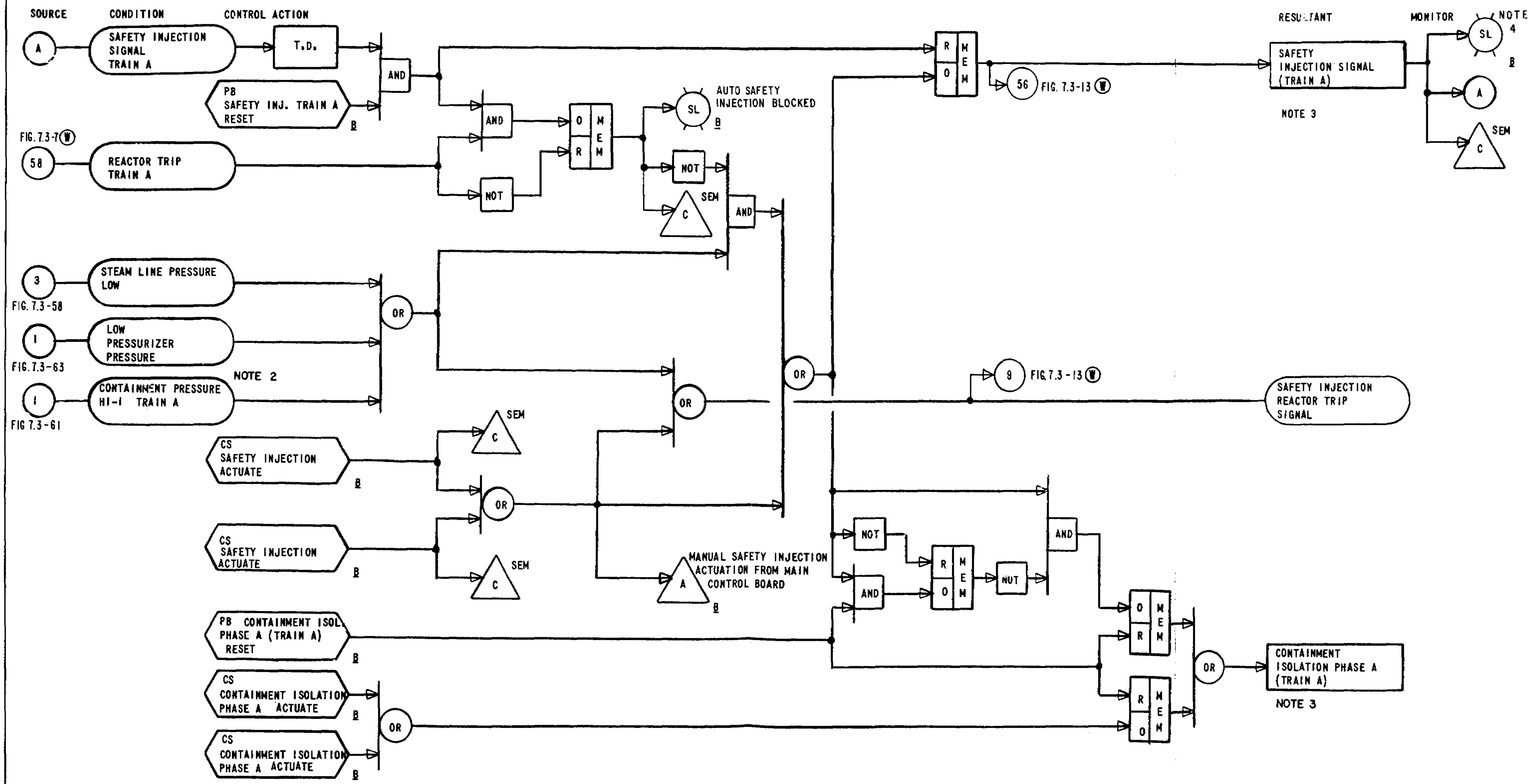
1. CONTAINMENT ISOLATION PHASE B (TRAIN A) SHOWN, CONTAINMENT ISOLATION PHASE B (TRAIN B) SIMILAR.
2. ANNUNCIATOR COMMON TO BOTH TRAINS.
3. MANUAL ACTUATION CONSISTS OF FOUR MOMENTARY CONTROLS, CONTAINMENT ISOLATION PHASE B ACTUATION WILL OCCUR ONLY IF TWO ASSOCIATED CONTROLS ARE OPERATED SIMULTANEOUSLY.
4. WHEN TWO CHANNELS ARE TESTED SIMULTANEOUSLY THE TEST VIOLATION ANNUNCIATOR IS ACTUATED.
5. CONTAINMENT ISOLATION PHASE B
6. CONTAINMENT PRESSURE HIGH/HIGH-HIGH
7. 2LMS-PR950 ALSO SHOWN ON FIG. 7.3-61

FIGURE 7.3-62
LOGIC DIAGRAM - CONTAINMENT DEPRESSURIZATION AND ISOLATION SIGNAL INITIATION SYSTEM

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

NOTES:
1. CONTROL AT MAIN BOARD SHOWN. CONTROL AT SHUTDOWN PANEL SIMILAR.
2. LOGIC FOR TRAIN A IS SHOWN. LOGIC FOR TRAIN B IS SIMILAR.
3. REDUNDANT MANUAL BLOCK-RESET CONSISTS OF TWO MOMENTARY CONTROLS AT THE CONTROL ROOM, ONE FOR EACH TRAIN.
4. PRESSURIZER SAFETY INJECTION BLOCKED. RED (BLOCK) AND GREEN (RESET) IND. LIGHTS PROVIDED AT SDP.
5. PRESSURIZER LOW PRESSURE REACTOR TRIP AND SAFETY INJECTION
6. CONTROL AT SHUTDOWN PANEL
7. INST. FOR PRESSURIZER PRESSURE HIGH REACTOR TRIP SHOWN. INST. FOR PRESSURIZER PRESSURE LOW REACTOR TRIP SIMILAR.
8. P-11 PERMISSIVE.

FIGURE 7.3-63
LOGIC DIAGRAM - SAFETY INJECTION AND CONTAINMENT ISOLATION PHASE A
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTE:

1. LOGIC FOR TRAIN A IS SHOWN.
   LOGIC FOR TRAIN B IS SIMILAR.
2. MONITOR DEVICES ARE SHOWN ON LOGIC DIAGRAM 27-12A.
3. REFER TO LSK-27-15 FOR A SUMMARY OF COMPONENTS ACTUATED BY CIA AND SIS.
4. SAFETY INJECTION SIGNAL.

FIGURE 7.3-64
LOGIC DIAGRAM - SAFETY INJECTION AND CONTAINMENT ISOLATION PHASE A
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

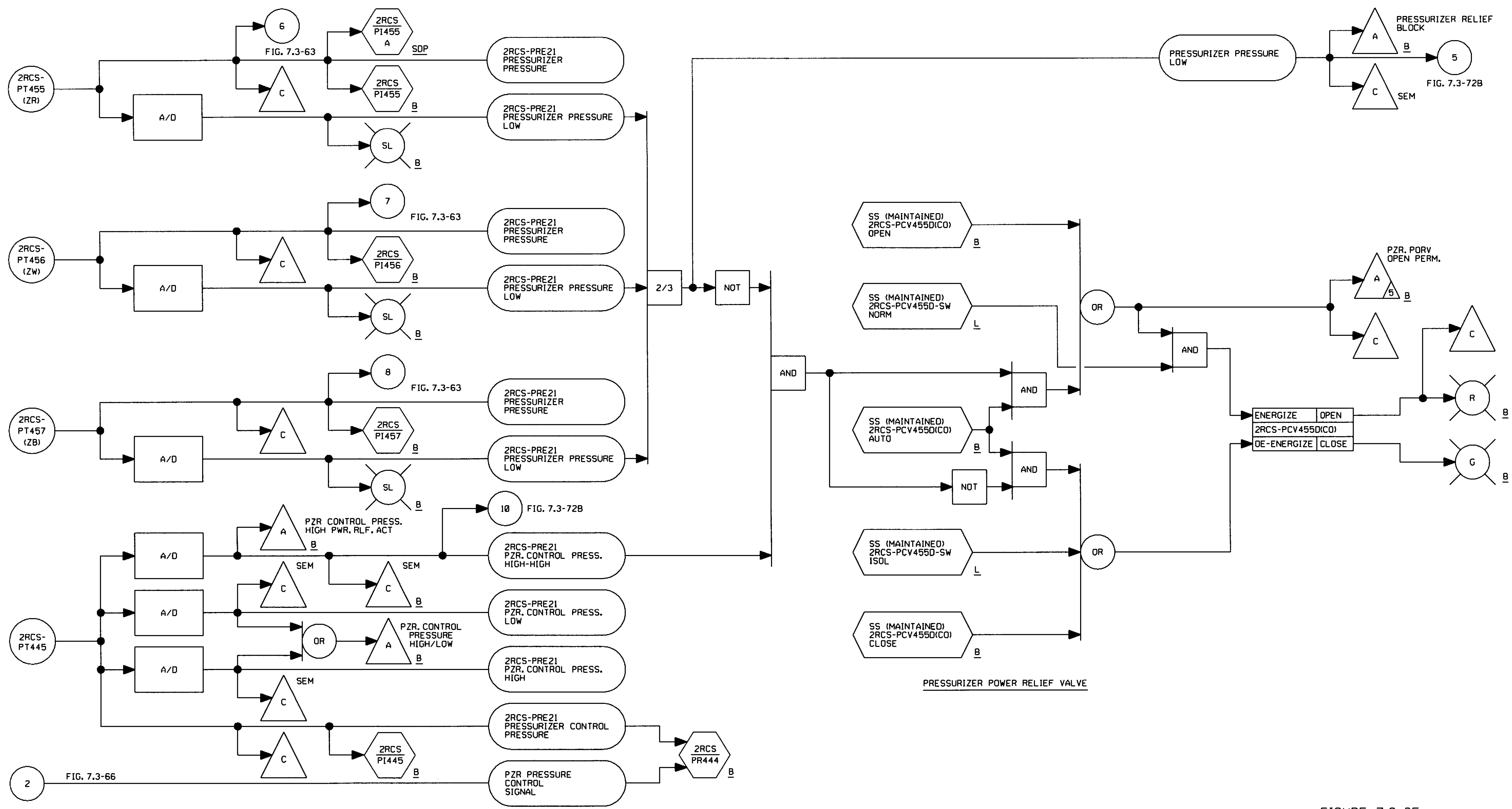


FIGURE 7.3-65
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

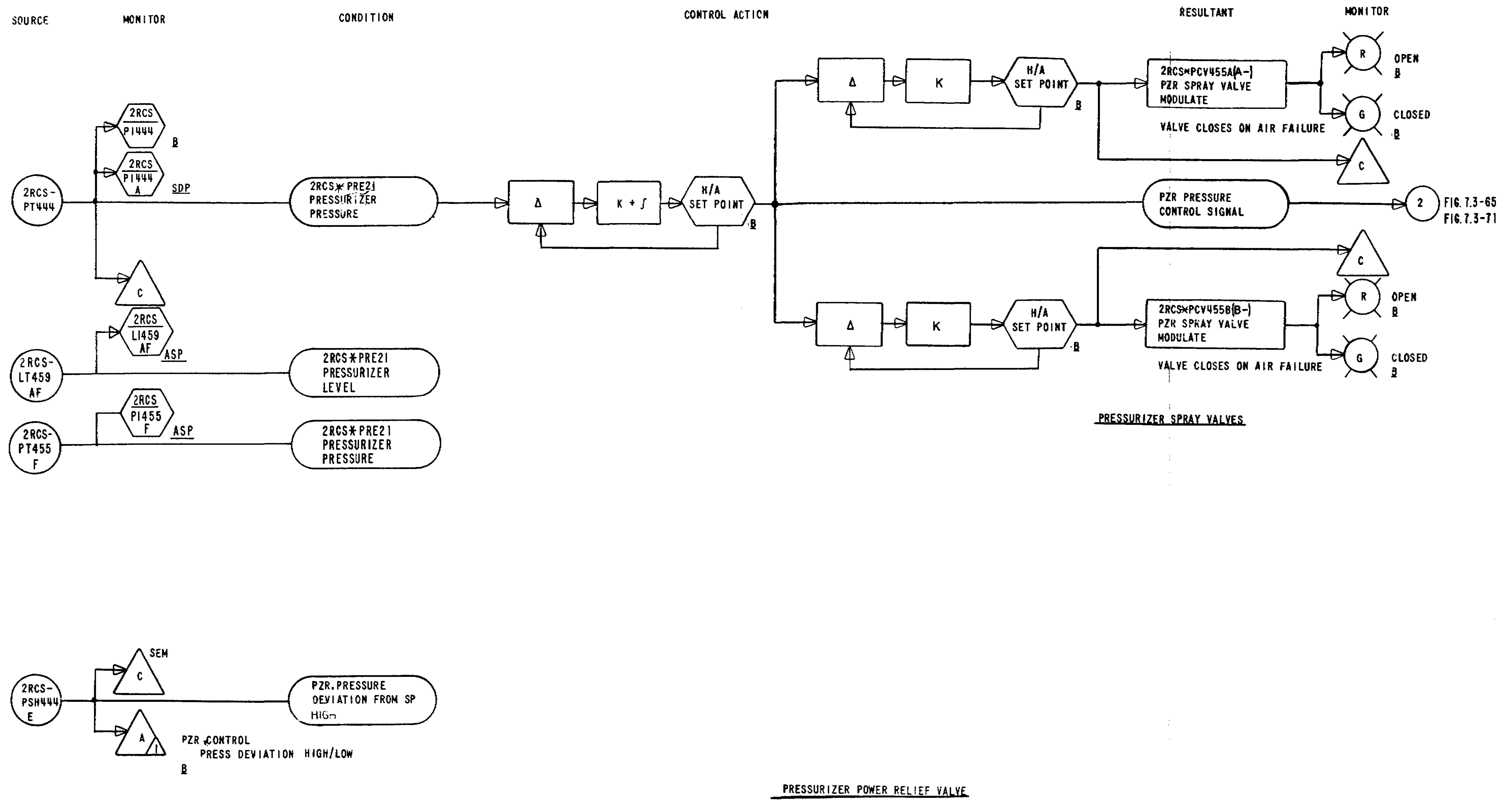


FIGURE 7.3-66
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

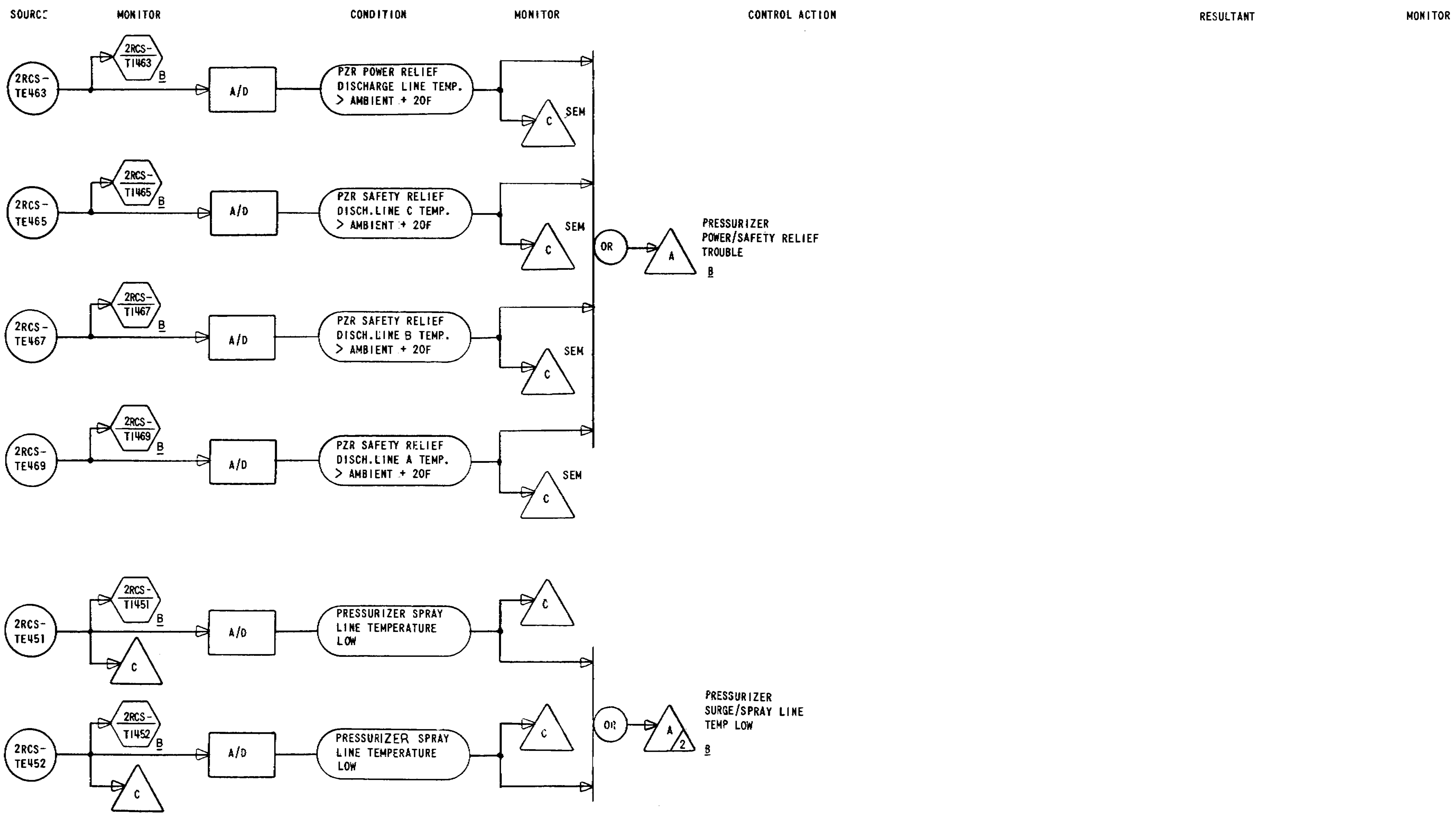


FIGURE 7.3-67
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

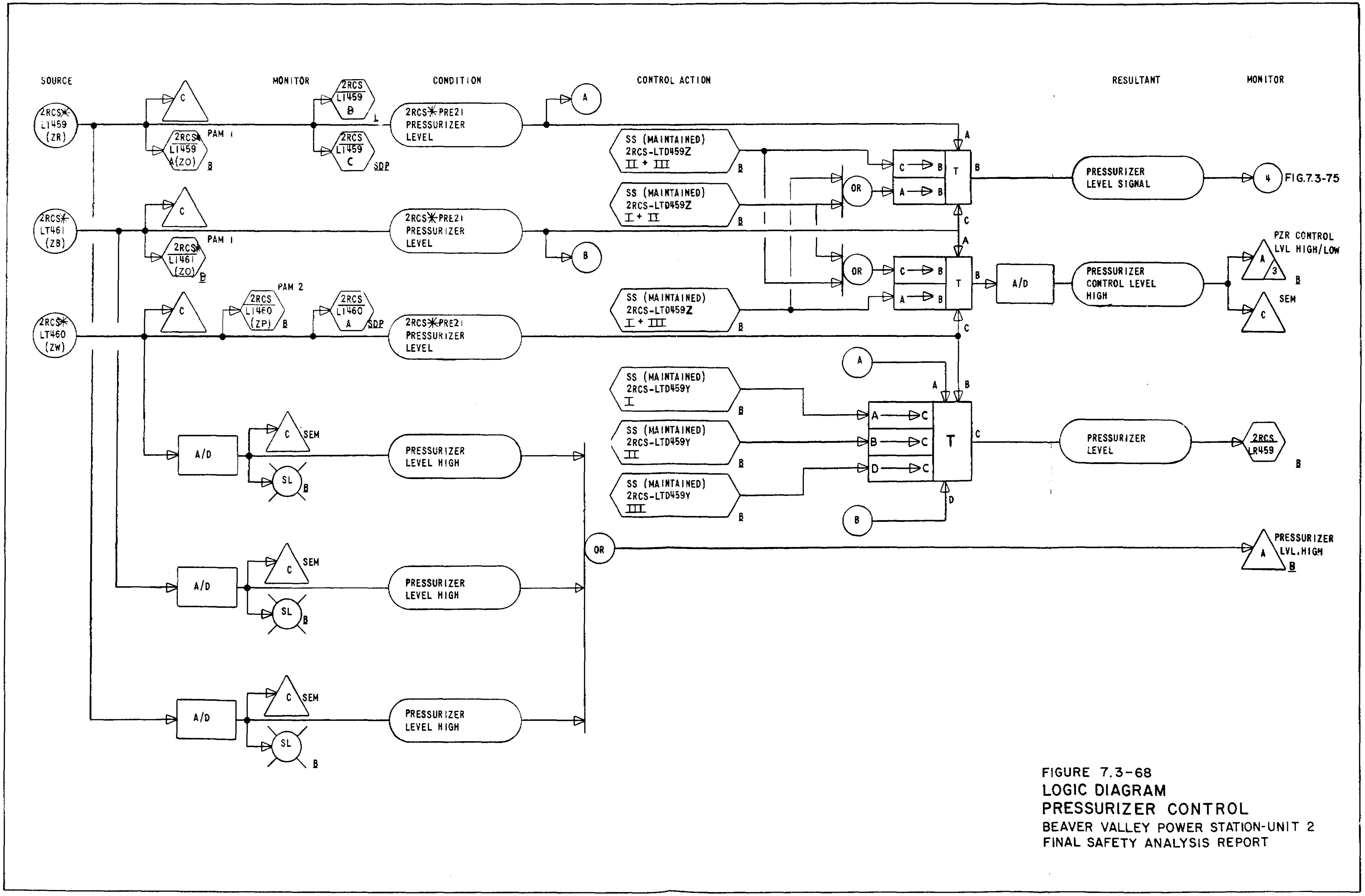


FIGURE 7.3-68
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

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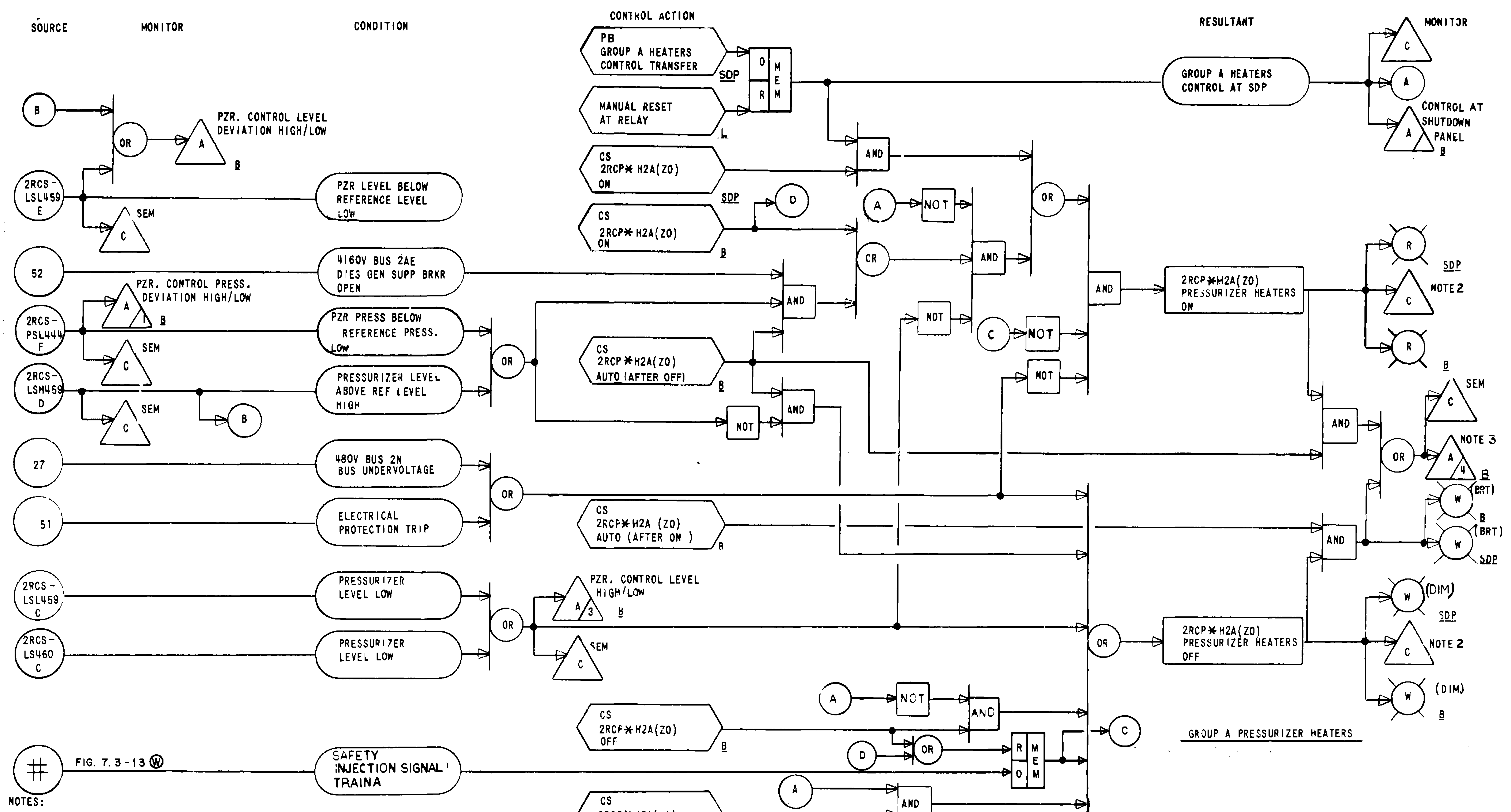
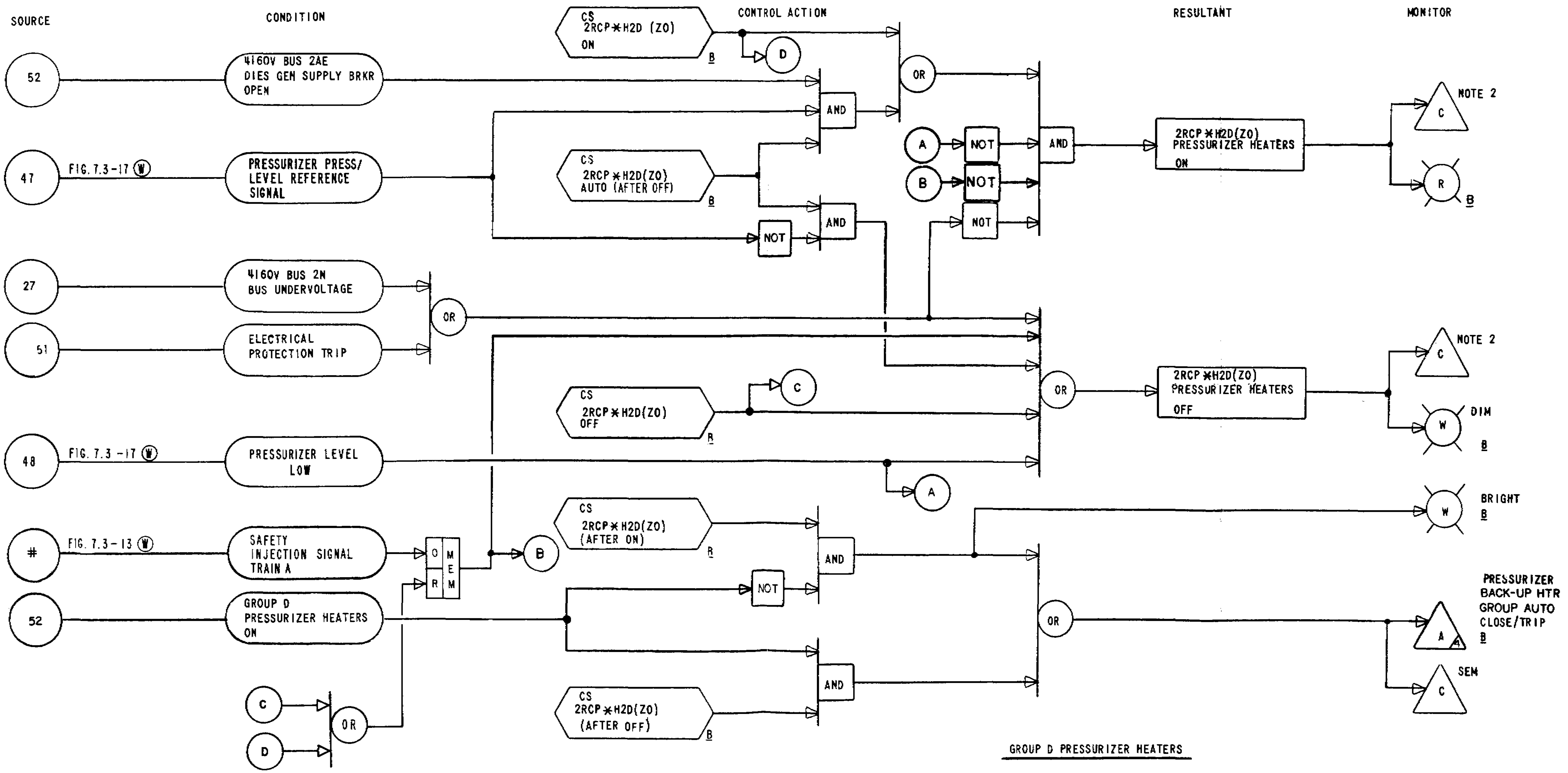


NOTES:

1. LOGIC FOR GROUP A HEATERS (TRAIN A) SHOWN, LOGIC FOR GROUP B HEATERS (TRAIN B) SIMILAR, EXCEPT NO CONTROL IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
2. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.
3. PRESSURIZER BACKUP HEATER GROUP AUTO CLOSE/TRIP.
4. ONLY THE MANUAL MODE OF OPERATION IS AVAILABLE FROM THE SHUTDOWN PANEL
5. LOGIC FOR PRESSURIZER HEATERS 2RCP-H2A(ZO) ALSO SHOWN ON FIG. 7.3-72C

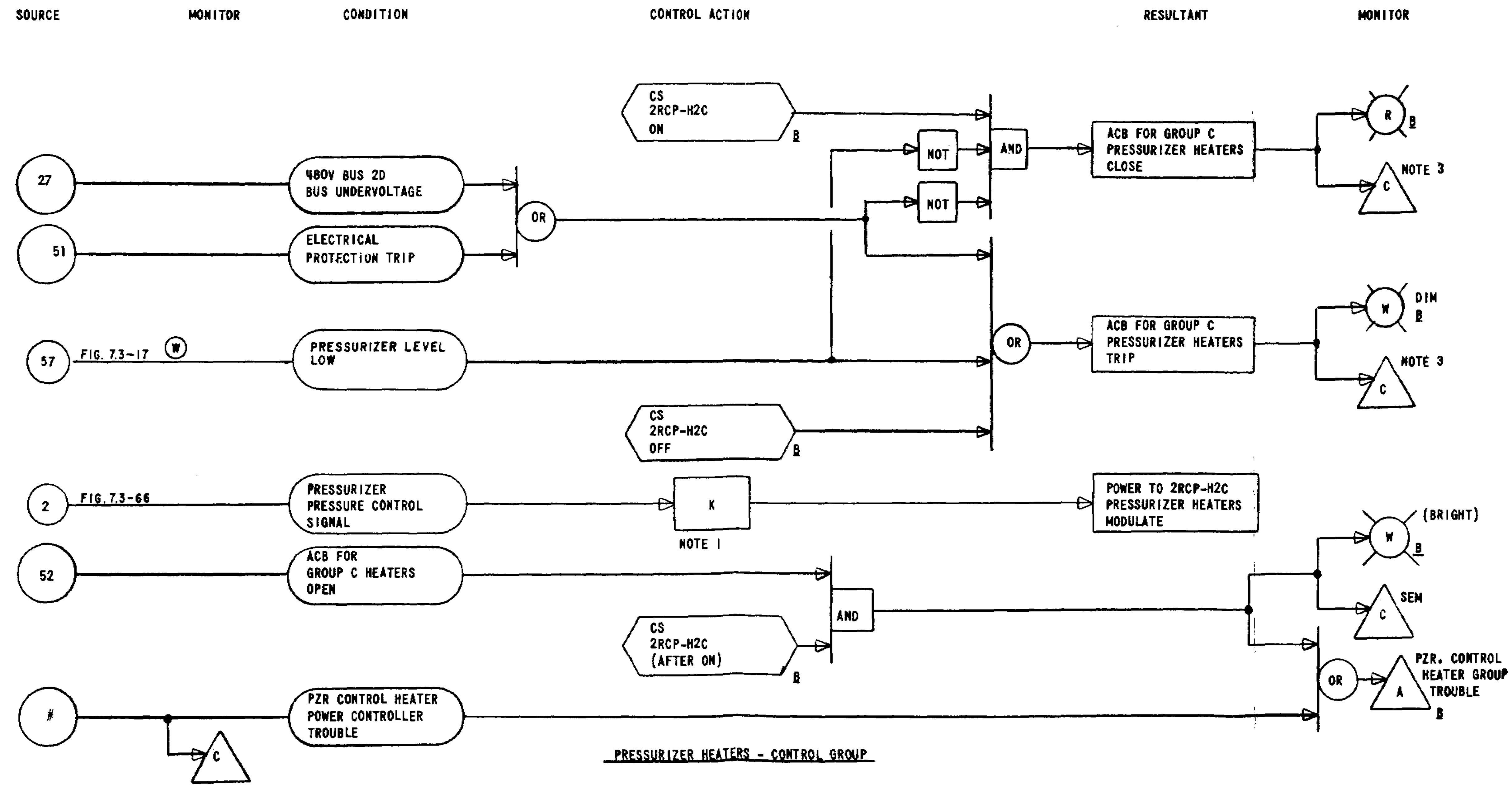
FIGURE 7.3-69
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR GROUP D PRESSURIZER HEATERS (TRAIN A) SHOWN. LOGIC FOR GROUP E PRESSURIZER HEATERS (TRAIN B) SIMILAR.
2. ONE COMPUTER INPUT WILL PROVIDE BOTH HEATER ON AND OFF INDICATIONS.

FIGURE 7.3-70
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. SILICON CONTROLLED RECTIFIER (SCR) TO CONTROL POWER TO GROUP C PRESSURIZER HEATERS.
2. # BY WESTINGHOUSE.
3. ONE COMPUTER INPUT WILL PROVIDE BOTH TRIP AND CLOSE BREAKER POSITION INDICATIONS.

FIGURE 7.3-71
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

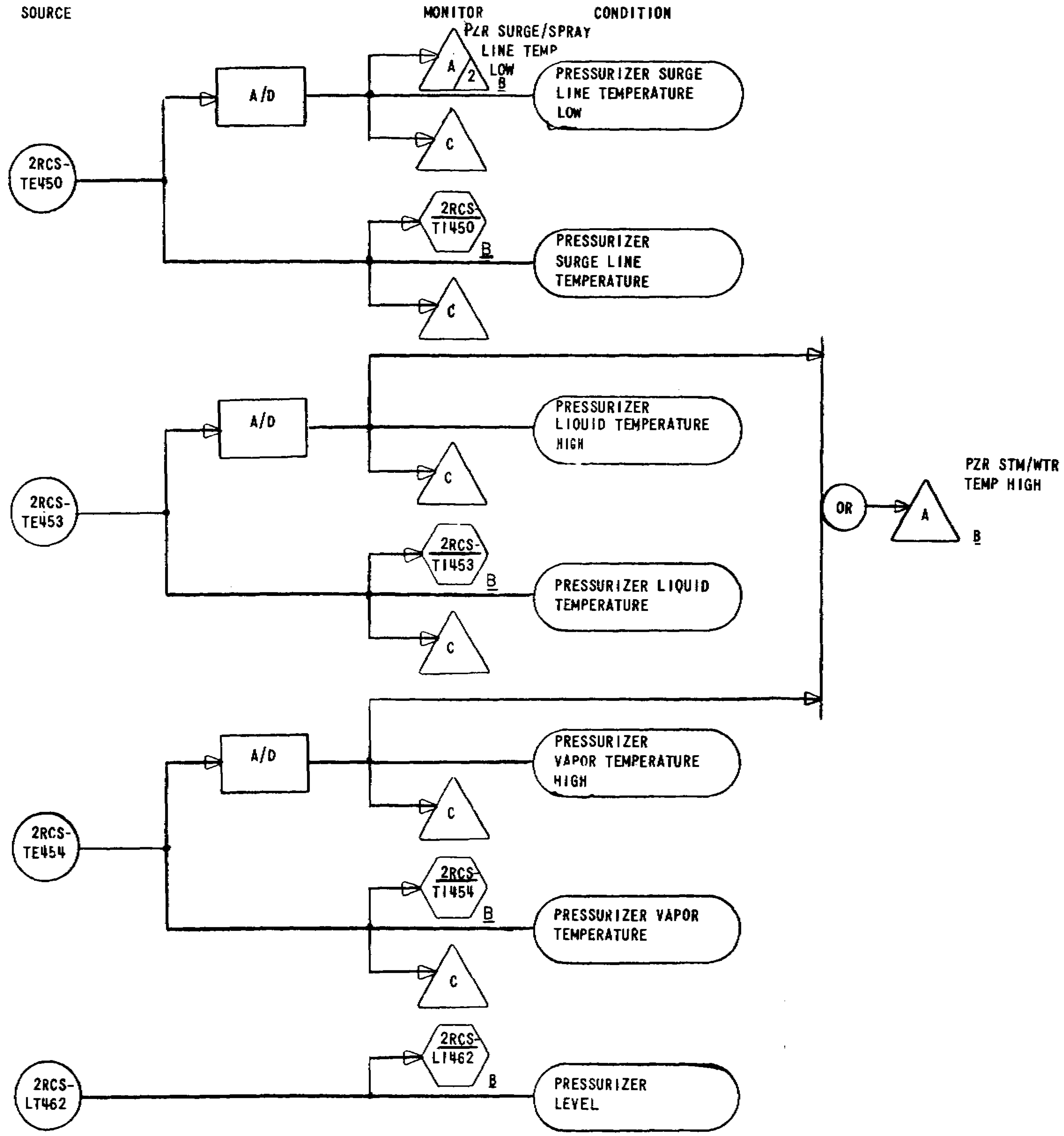


FIGURE 7.3-72
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12

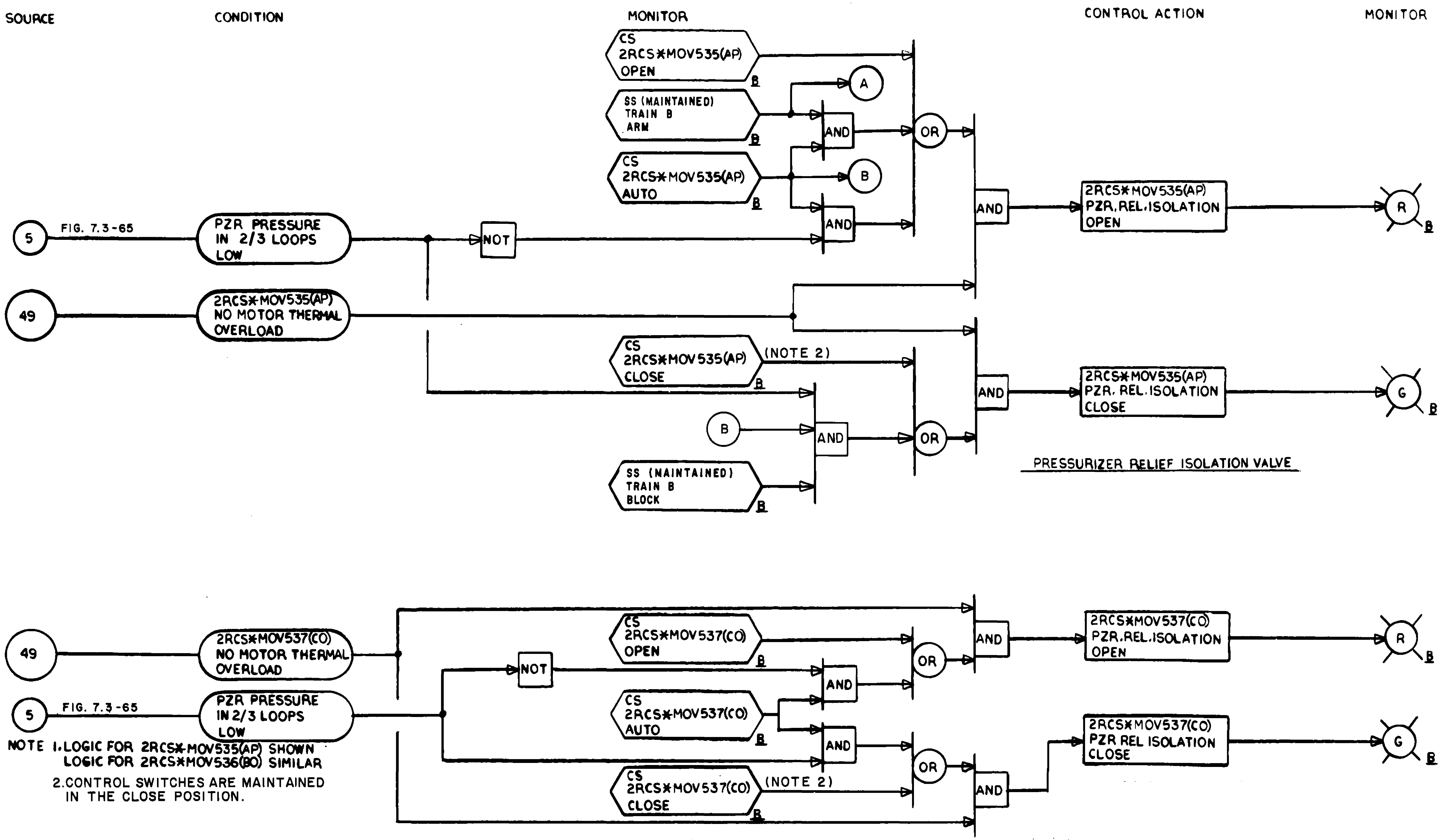
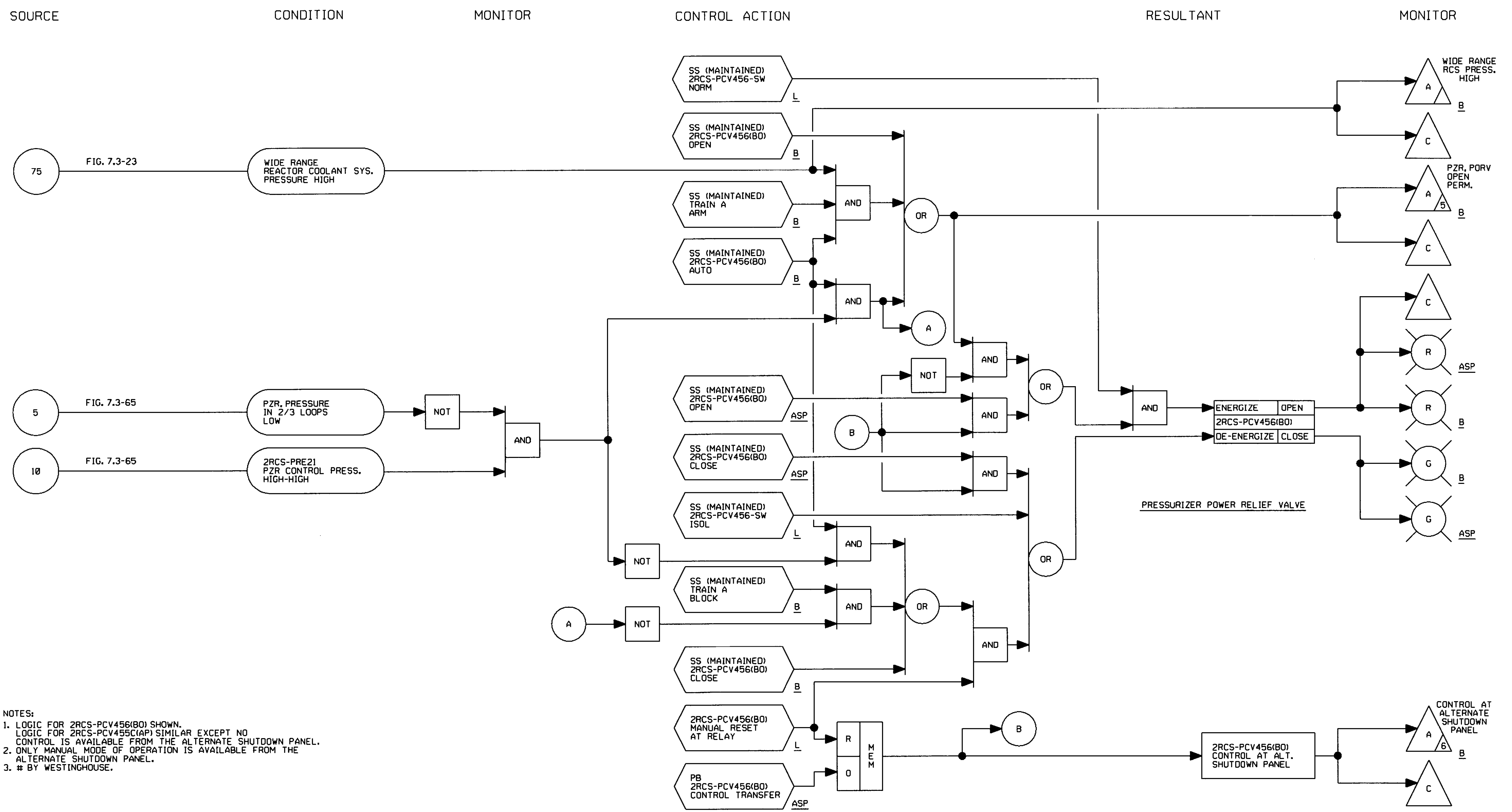
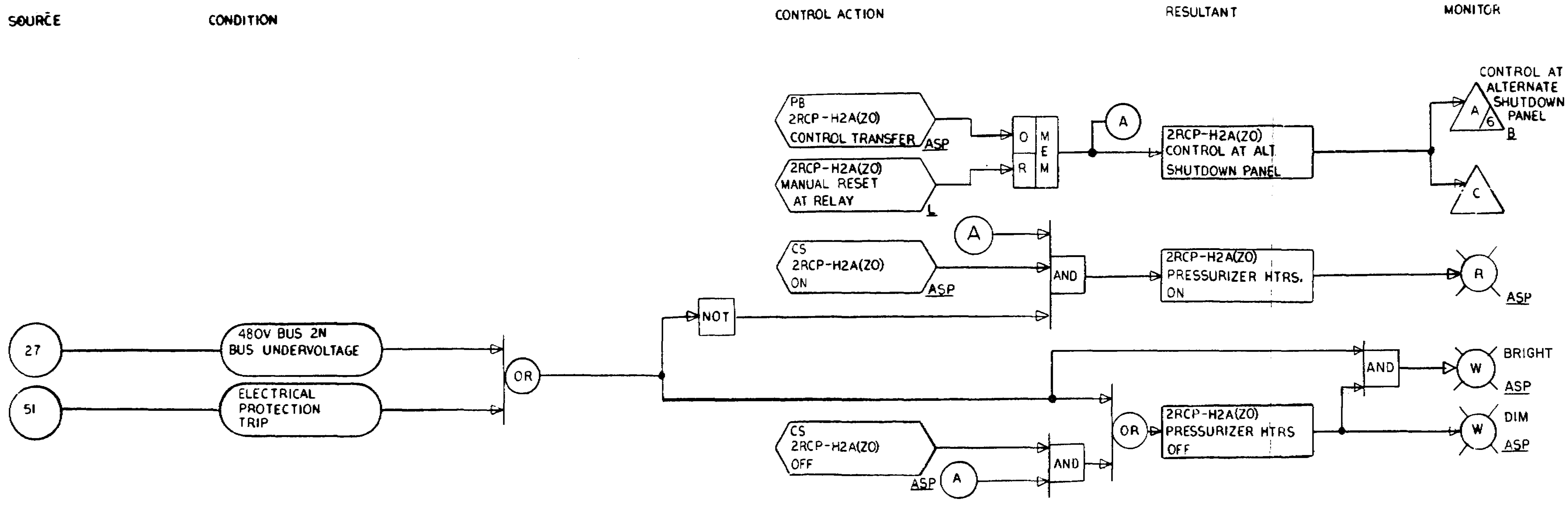


FIGURE 7.3-72A
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:
1. LOGIC FOR 2RCS-PCV456(BO) SHOWN.
   LOGIC FOR 2RCS-PCV455C(AP) SIMILAR EXCEPT NO
   CONTROL IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
2. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE
   ALTERNATE SHUTDOWN PANEL.
3. # BY WESTINGHOUSE.

FIGURE 7.3-72B
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:
1. ONLY THE MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL
2. LOGIC FOR PRESSURIZER HEATERS 2RCP-H2A(ZO) ALSO SHOWN ON FIG. 7.3-69

FIGURE 7.3-72C
LOGIC DIAGRAM
PRESSURIZER CONTROL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

NOTES:

1. LOGIC FOR CHARGING PUMP 2CHS•P21A(AO) SHOWN, LOGIC FOR PUMP 2CHS•P21B(BP) SIMILAR.
2. CONTROL FROM BENCH BOARD SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR.
3. CONTROL FROM BENCH BOARD AVAILABLE ONLY AFTER MANUAL RESET OF CONTROL TRANSFER SWITCH.
4. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
5. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.
6. SEE ADDITIONAL CONTROL OF 2CHS•P21A(AO) ON FIG. 7.3-77A.

FIGURE 7.3-73
LOGIC DIAGRAM
CHARGING PUMPS

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

10080-LSK-26-1B

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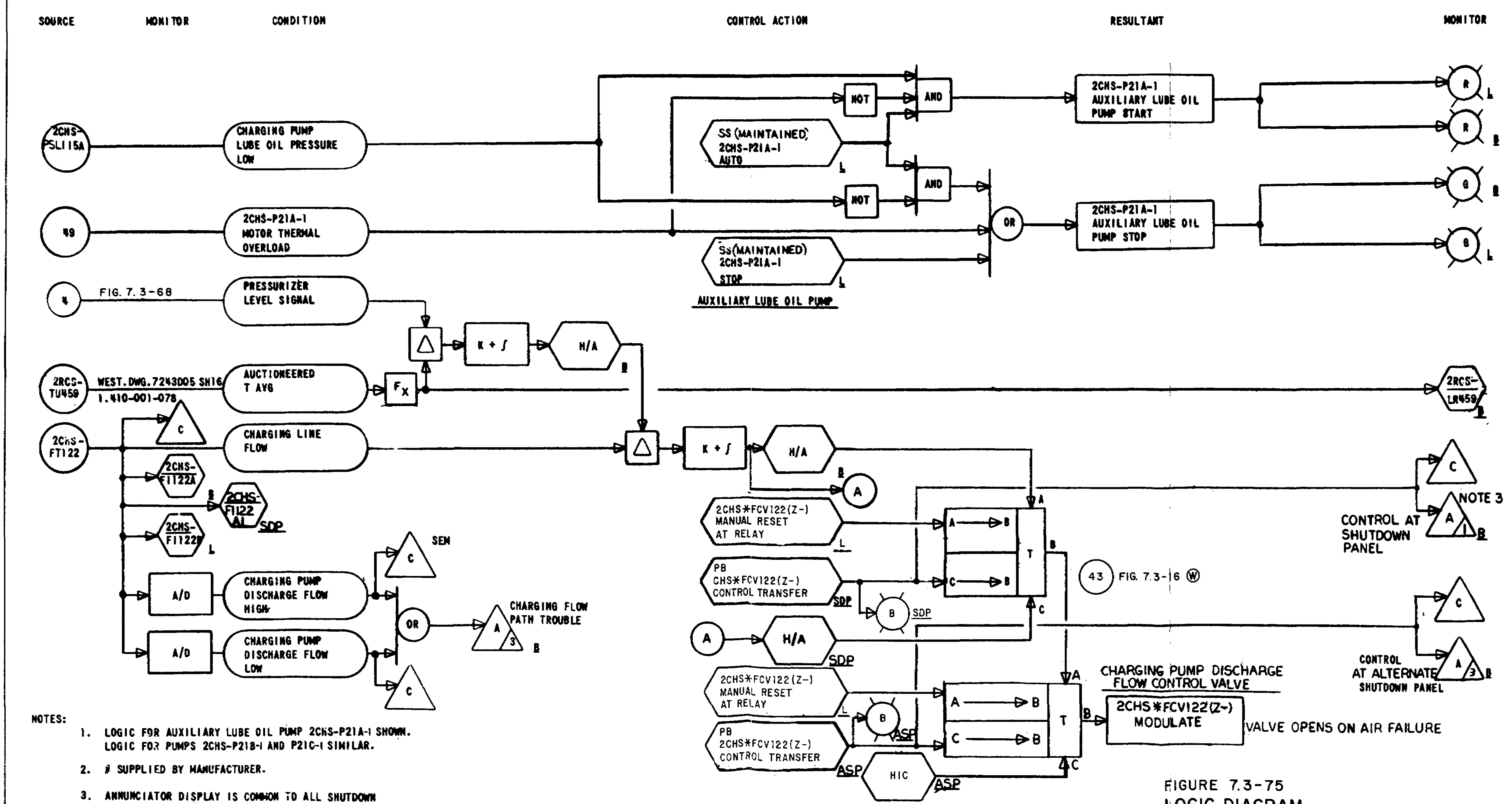
NOTES:

1. LOGIC FOR CHARGING PUMP ON BUS 2AE SHOWN. LOGIC FOR PUMP ON BUS 2DF SIMILAR.
2. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. CONTROL FROM BENCH BOARD SHOWN. CONTROL FROM SHUTDOWN PANEL SIMILAR.
4. CONTROL FROM BENCH BOARD AVAILABLE ONLY AFTER MANUAL RESET OF TRANSFER SWITCH.
5. FLOW INDICATORS ARE COMMON TO ALL CHARGING PUMPS.
6. ONE COMPUTER INPUT PROVIDES BOTH ON AND OFF INDICATION.

FIGURE 7.3-74
LOGIC DIAGRAMS
CHARGING PUMPS
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR AUXILIARY LUBE OIL PUMP 2CHS-P21A-1 SHOWN. LOGIC FOR PUMPS 2CHS-P21B-1 AND P21C-1 SIMILAR.
2. # SUPPLIED BY MANUFACTURER.
3. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
4. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL

FIGURE 7.3-75
LOGIC DIAGRAM
CHARGING PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

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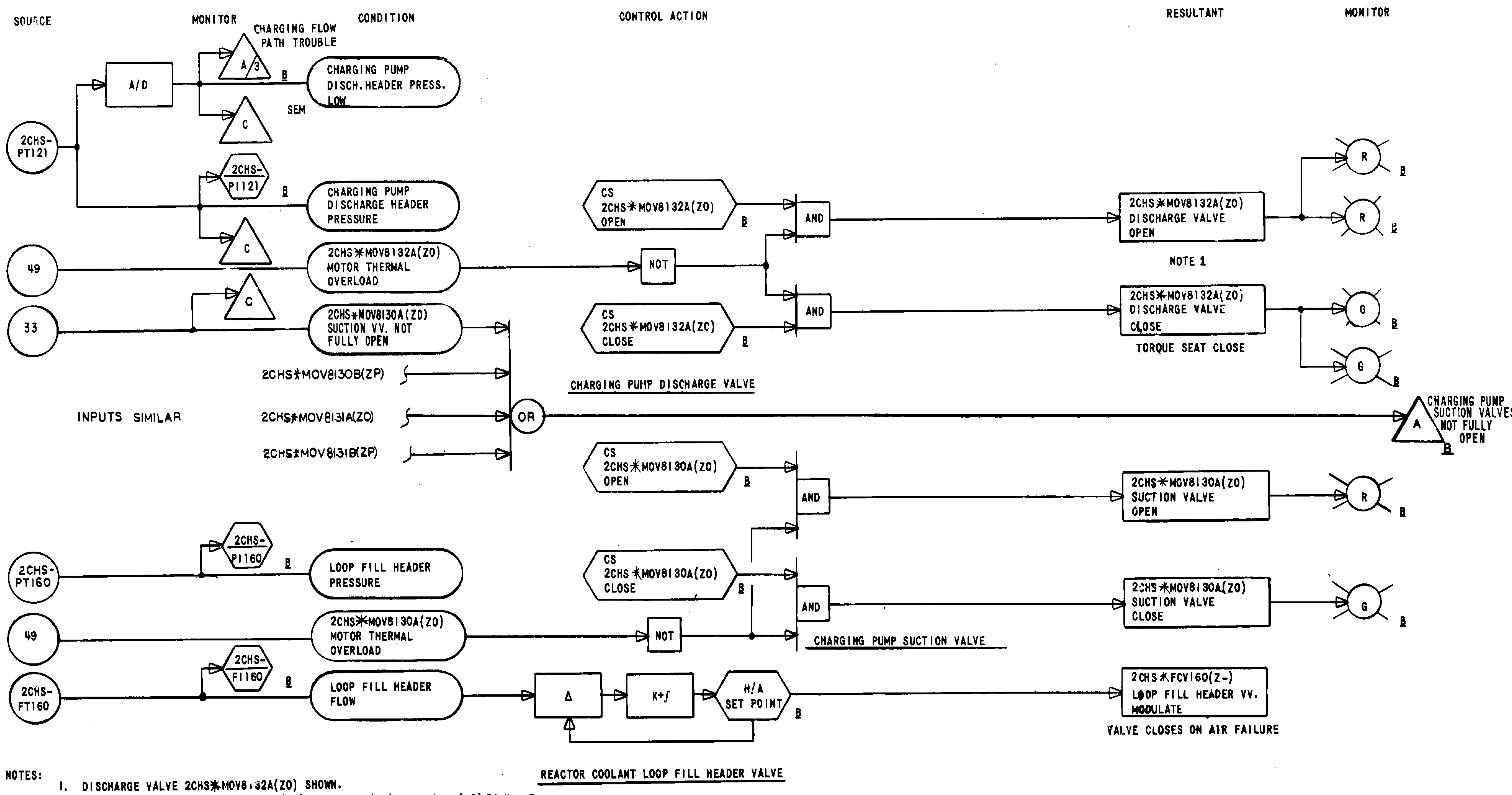
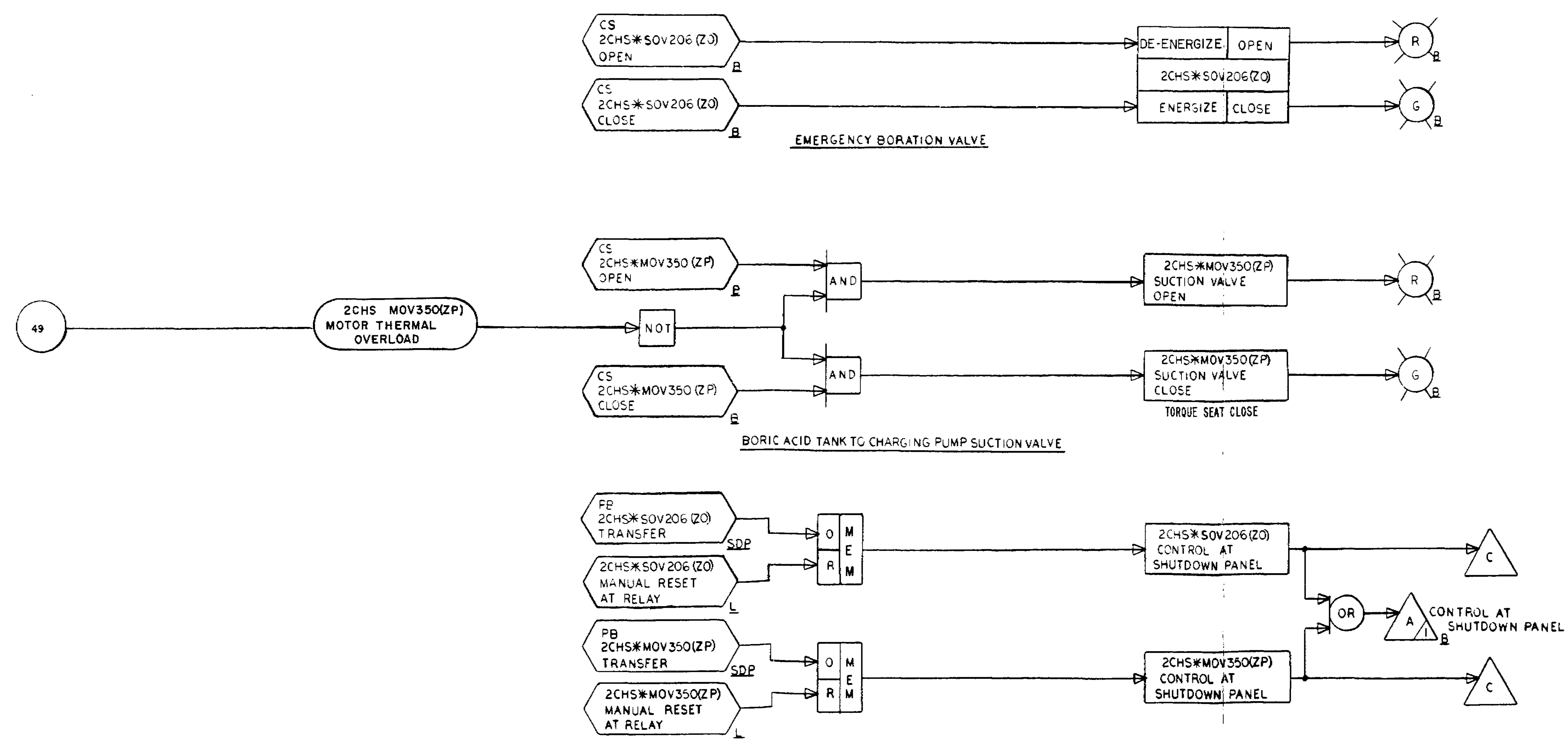


NOTES:

1. DISCHARGE VALVE 2CHS✱MOV8132A(ZO) SHOWN.
DISCHARGE VALVES 2CHS✱MOV8132B(ZP), ✱MOV8133A(ZO), ✱MOV8133B(ZP) SIMILAR.
2. DURING NORMAL PLANT OPERATION DISCHARGE VALVES 2CHS✱MOV8132A(ZO), ✱MOV8132B(ZP), ✱MOV8133A(ZO), AND ✱MOV8133B(ZP) ARE TO BE LEFT OPEN WITH THEIR POWER REMOVED. REFER TO FIG. 7.3-77B
3. SUCTION VALVE 2CHS✱MOV8130A(ZO) SHOWN. SUCTION VALVES 2CHS✱MOV8130B(ZP), ✱MOV8131A(ZO), ✱MOV8131B(ZP), LOOP FILL VALVES 2RCS✱MOV556A(A-), ✱MOV556B(B-), ✱MOV556C(C-).

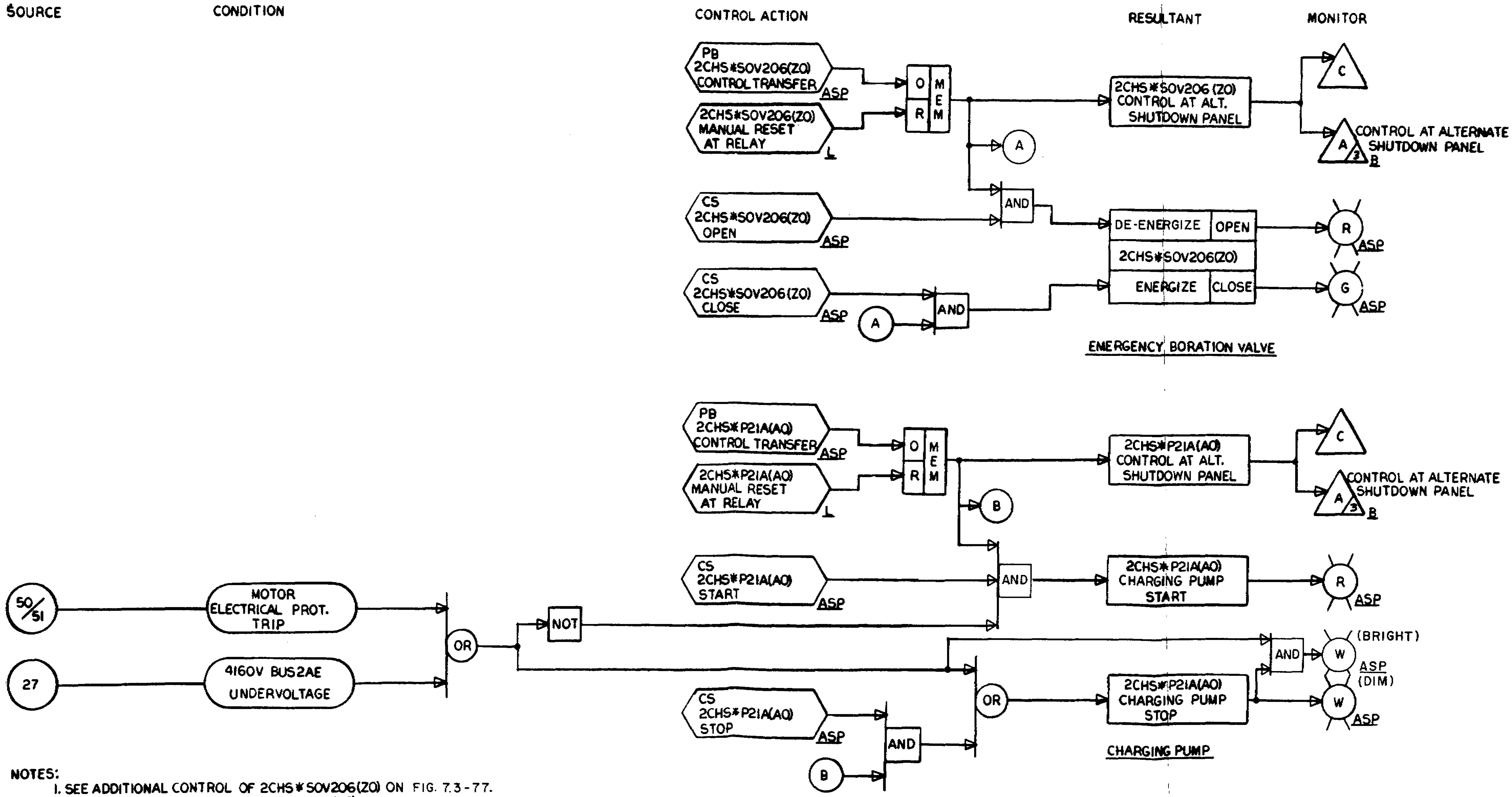
FIGURE 7.3-76
LOGIC DIAGRAM
CHARGING PUMPS

BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:
1. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES
2. CONTROL FROM BENCHBOARD FOR 2CHS*SOV206 SHOWN, CONTROL FOR 2CHS*MOV350 SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR.
3. SEE ADDITIONAL CONTROL OF 2CHS * SOV206 (ZO) ON FIG. 7.3-77A.

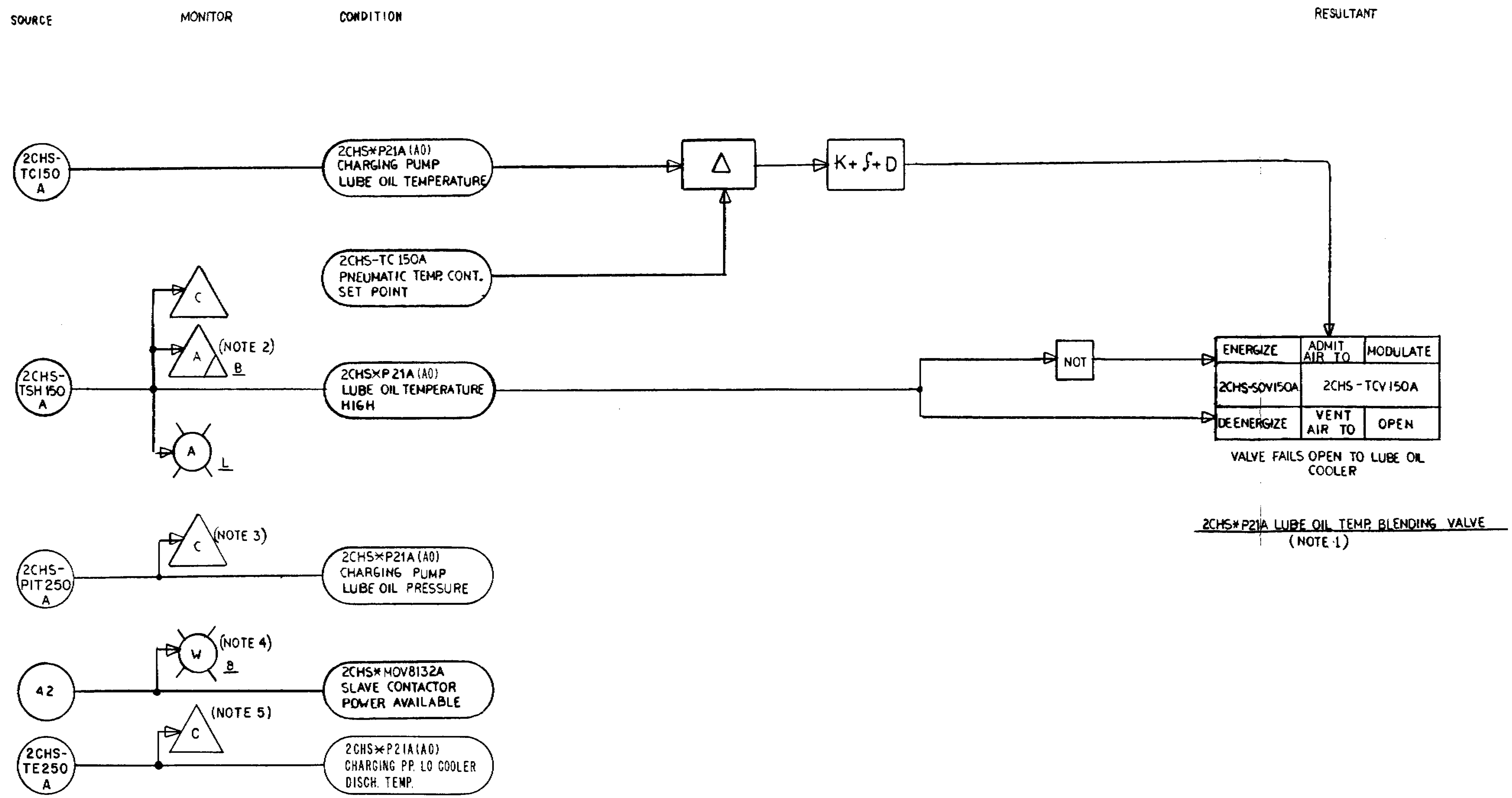
FIGURE 7.3-77
LOGIC DIAGRAM
CHARGING PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

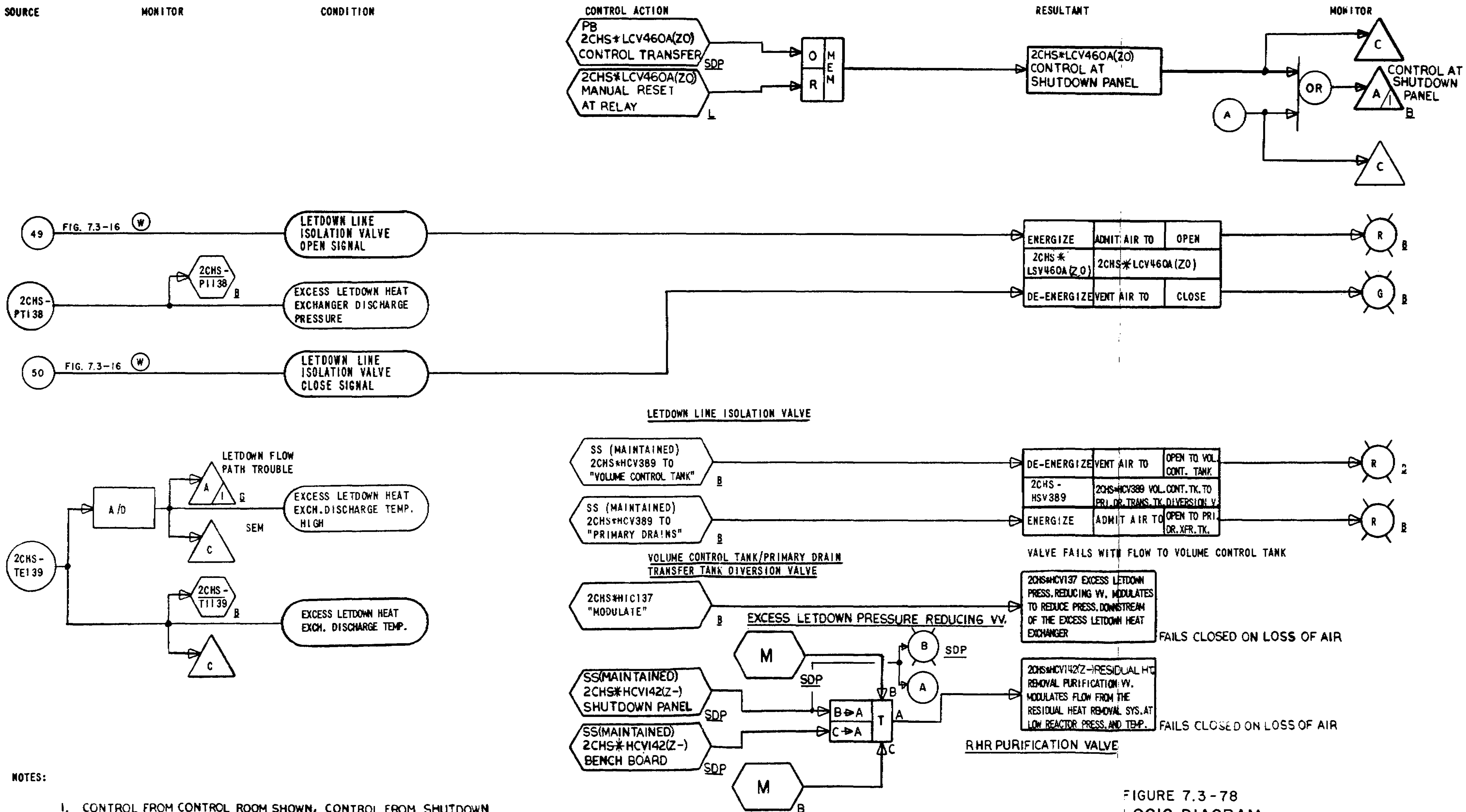
1. SEE ADDITIONAL CONTROL OF 2CHS*SOV206(ZO) ON FIG. 7.3-77.
2. SEE ADDITIONAL CONTROL OF 2CHS*P21A(AO) ON FIG. 7.3-73.
3. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.

FIGURE 7.3-77A
LOGIC DIAGRAM
CHARGING PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. 2CHS*P21A(AO) LUBE OIL TEMPERATE BLENDING VALVE 2CHS-TCV150A SHOWN. BLENDING VALVES 2CHS-TCV150B & 2CHS-TCV150C FOR 2CHS*P21B(BP) & 2CHS*P21C (SG) ARE SIMILAR.
2. CHARGING PUMP LUBE OIL TEMPERATURE HIGH COMPUTER POINT COMMON TO 2CHS-TSH150A, -TSH-150B, OR -TSH150C HIGH TEMPERATURE CONDITION.
3. CHARGING PUMP 2CHS-PIT250A LUBE OIL PRESSURE COMPUTER INPUT SHOWN. 2CHS-PIT250B & -PIT250C INPUTS SIMILAR.
4. 2CHS*MOV8132A SLAVE CONTACTOR POWER AVAILABLE INDICATION SHOWN. INDICATION FOR 2CHS*MOV8132B, *MOV8133A, & *MOV8133B SIMILAR. REFER TO FIG. 7.3-76 NOTE 2.
5. 2CHS-TE250A FOR 2CHS*P21A(AO) SHOWN, 2CHS-TE250B AND 2CHS-TE250C FOR 2CHS*P21B(BP) AND 2CHS*P21C(SG) SIMILAR.

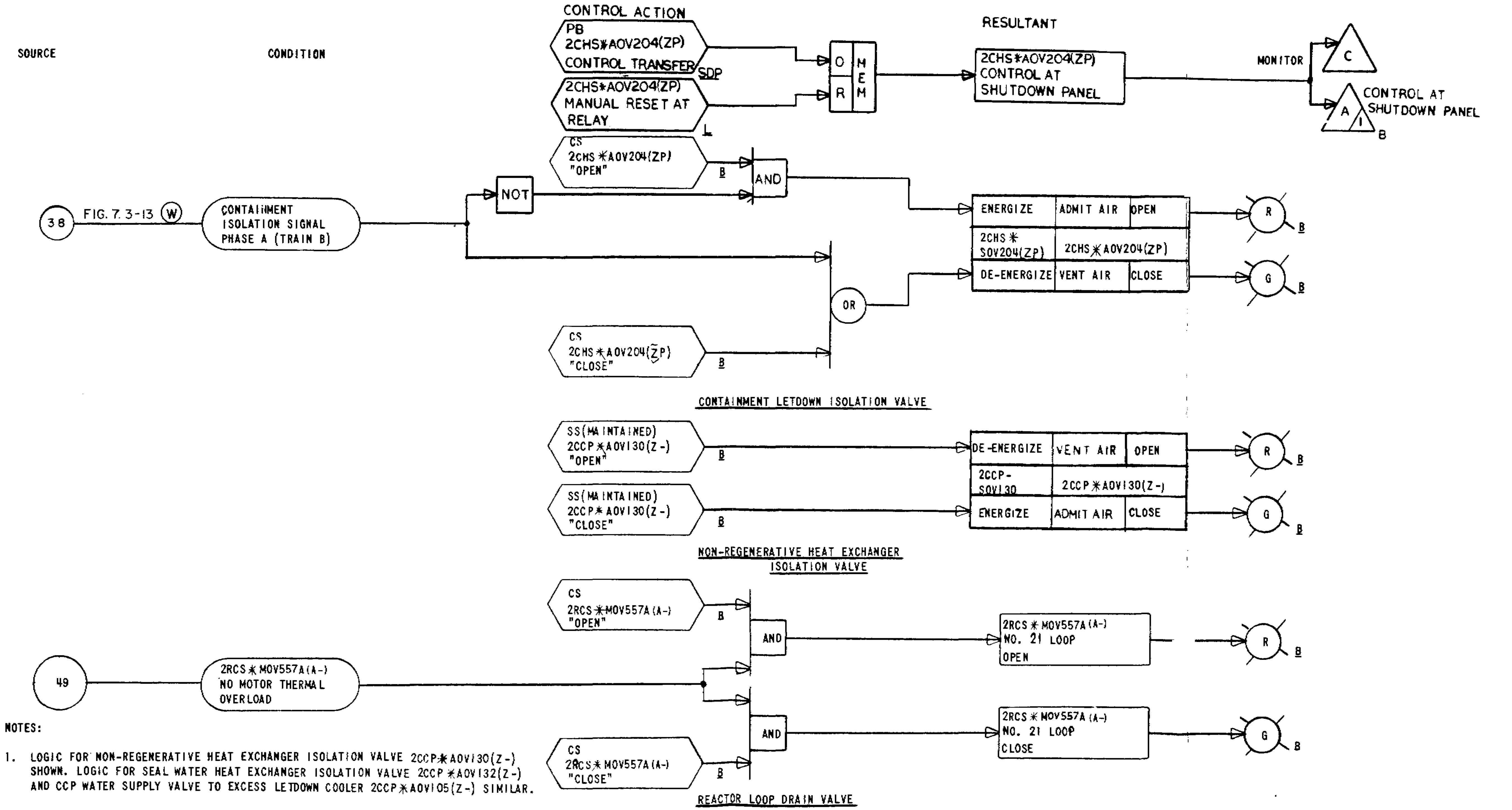
FIGURE 7.3-77B
LOGIC DIAGRAM
CHARGING PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. CONTROL FROM CONTROL ROOM SHOWN. CONTROL FROM SHUTDOWN PANEL SIMILAR FOR 2CHS*LCV460A(ZO),*LCV460B(ZO).
2. LOGIC FOR LETDOWN LINE ISOLATION VALVES 2CHS*LCV460A(ZO) AND 2CHS*LCV460B(ZO) ALSO SHOWN ON FIG. 7.3-82A.

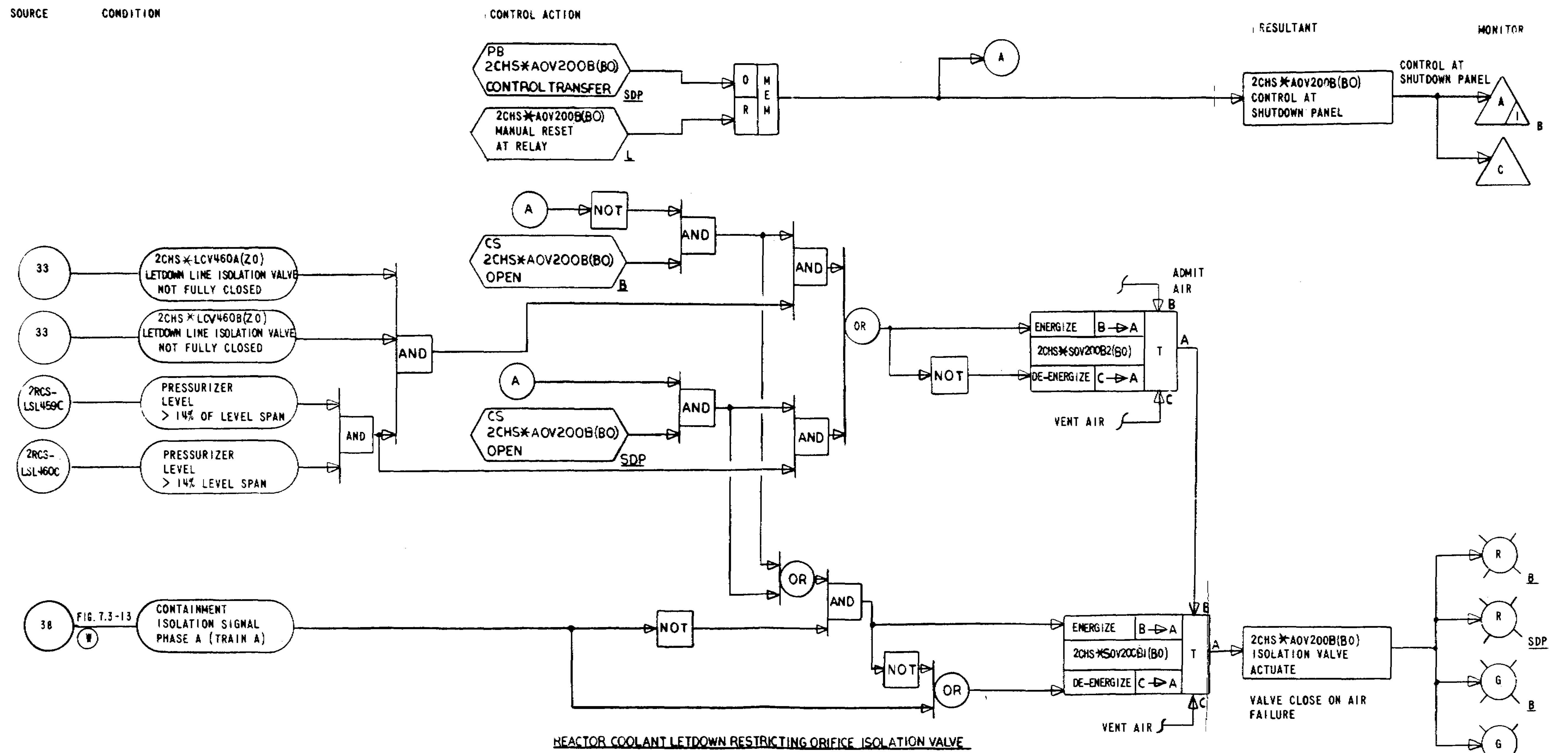
FIGURE 7.3-78
LOGIC DIAGRAM
REACTOR COOLANT SYSTEM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR NON-REGENERATIVE HEAT EXCHANGER ISOLATION VALVE 2CCP*AOV130(Z-) SHOWN. LOGIC FOR SEAL WATER HEAT EXCHANGER ISOLATION VALVE 2CCP*AOV132(Z-) AND CCP WATER SUPPLY VALVE TO EXCESS LETDOWN COOLER 2CCP*AOV105(Z-) SIMILAR.
2. LOGIC FOR NO. 21 LOOP DRAIN VALVE 2RCS*MOV557A(A-) SHOWN. LOGIC FOR NO. 22 AND NO. 23 LOOP DRAIN VALVES 2RCS*MOV557B(B-) AND *MOV557C(C-) SIMILAR.
3. CONTROL FROM CONTROL ROOM SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR FOR 2CHS*AOV204(ZP)

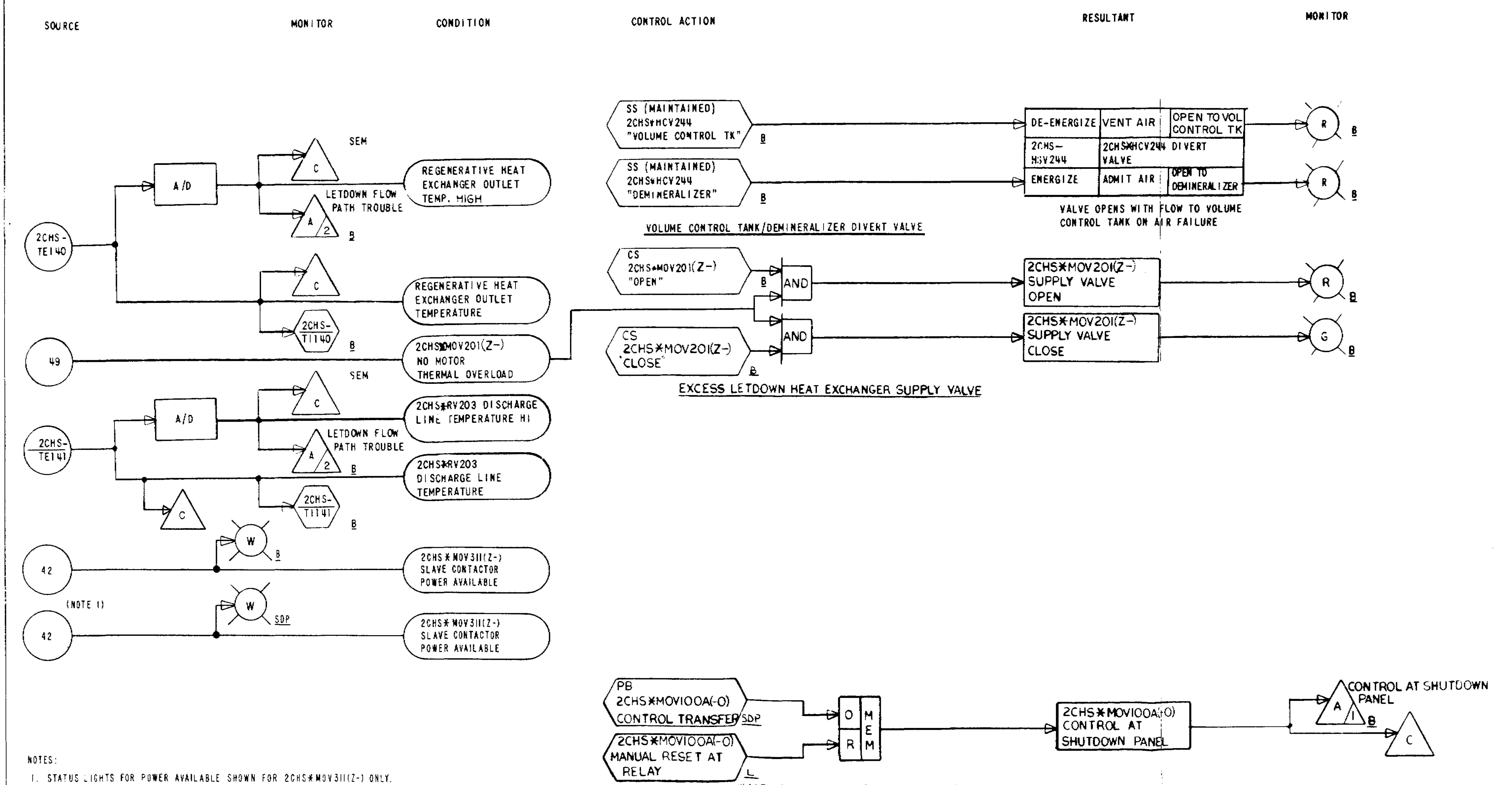
FIGURE 7.3-79
LOGIC DIAGRAM
REACTOR COOLANT SYSTEM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES;

1. LOGIC FOR LETDOWN ORIFICE ISOLATION VALVE 2CHS*AOV200B(BO) SHOWN.
   LOGIC FOR LETDOWN ORIFICE ISOLATION VALVE 2CHS*AOV200C(CO) AND *AOV200C(CO)SIMILAR.
2. ANNUNCIATOR AND COMPUTER INPUT COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. CONTROL FROM THE CONTROL ROOM IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER RELAY HAS BEEN MANUALLY RESET. CONTROL FROM THE SHUTDOWN PANEL IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER RELAY HAS BEEN ACTUATED.

FIGURE 7.3-80
LOGIC DIAGRAM
REACTOR COOLANT SYSTEM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. STATUS LIGHTS FOR POWER AVAILABLE SHOWN FOR 2CHS*MOV311(Z-) ONLY.
2. LOGIC FOR EXCESS LETDOWN HEAT EXCHANGE SUPPLY VALVE 2CHS*MOV201(Z-) SHOWN LOGIC FOR LETDOWN SUPPLY VALVE TO PRESSURIZER SPRAY 2CHS*MOV311(Z) CCP WATER TO NON-REGENERATIVE/SEAL WATER HEAT EXCHANGER SUPPLY VALVE 2CCP*MOV173(ZP) 2CHS*MOV100A(-O) AND *MOV100B(-O) LETDOWN TO COOLANT RECOVERY TANKS SIMILAR.
3. CONTROL FROM MAIN BOARD SHOWN CONTROL FROM SHUTDOWN PANEL SIMILAR FOR 2CHS *MOV311(Z-), *MOV100A(-O), AND *MOV100B(-O)
4. LOGIC FOR 2CHS*MOV100A(-O) AND 2CHS*MOV100B(-O) ALSO SHOWN ON FIG. 7.3-82A
5. AUXILIARY SPRAY VALVE 2CHS*MOV311(Z-) HAS POWER REMOVED BY MEANS OF A BANNANA PLUG ON THE MCB.

FIGURE 7.3-81
LOGIC DIAGRAM
REACTOR COOLANT SYSTEM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

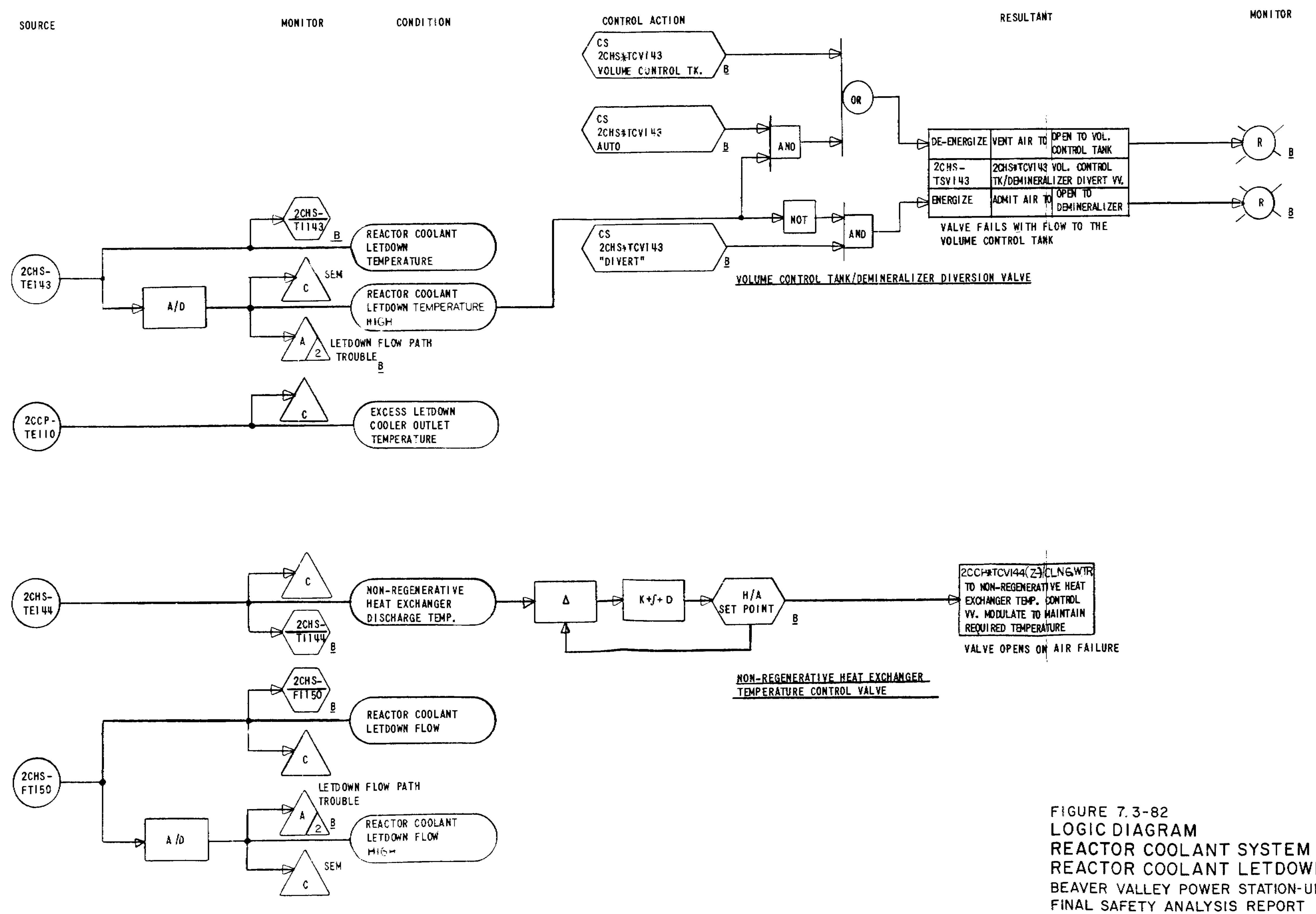
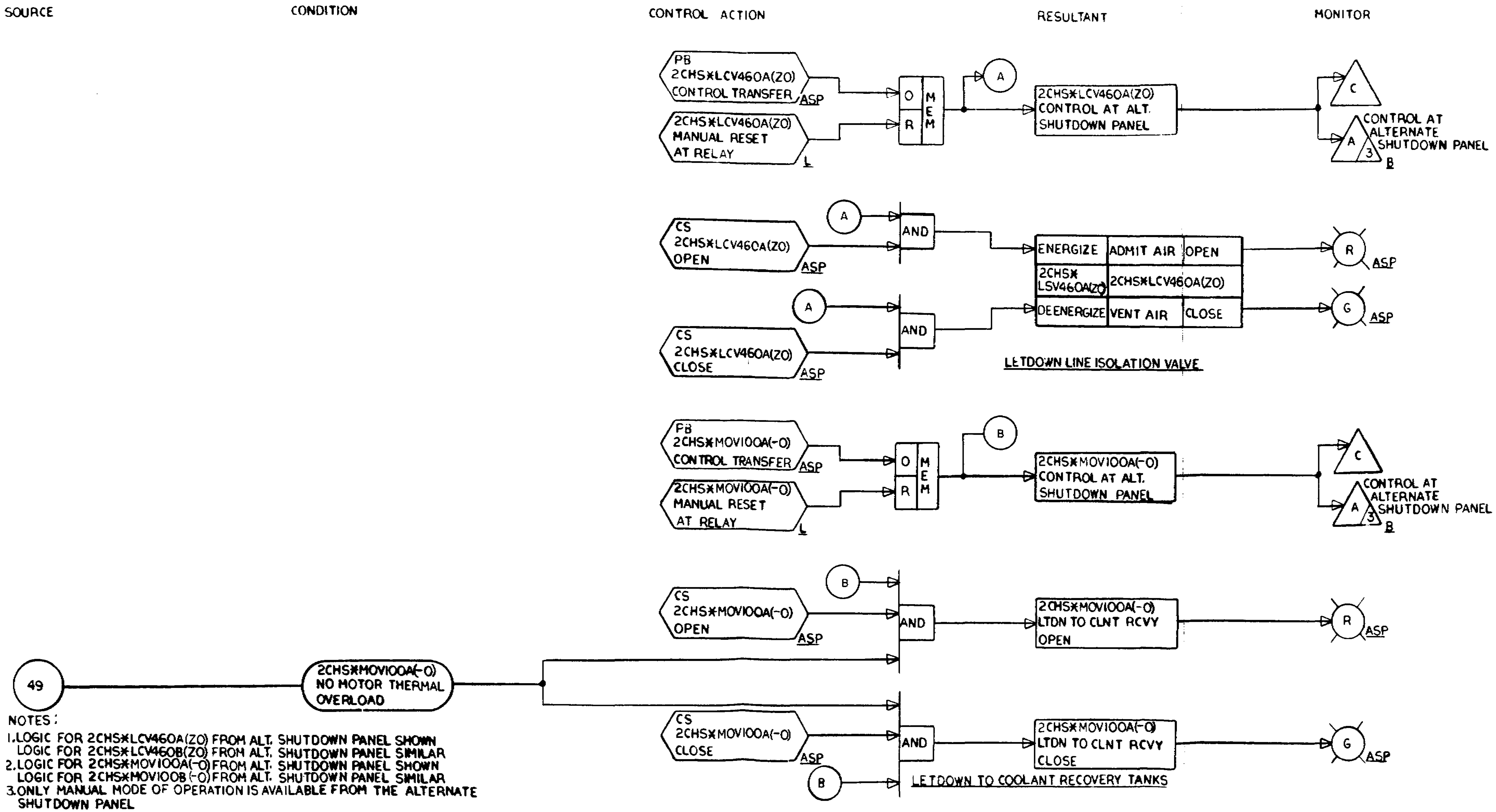
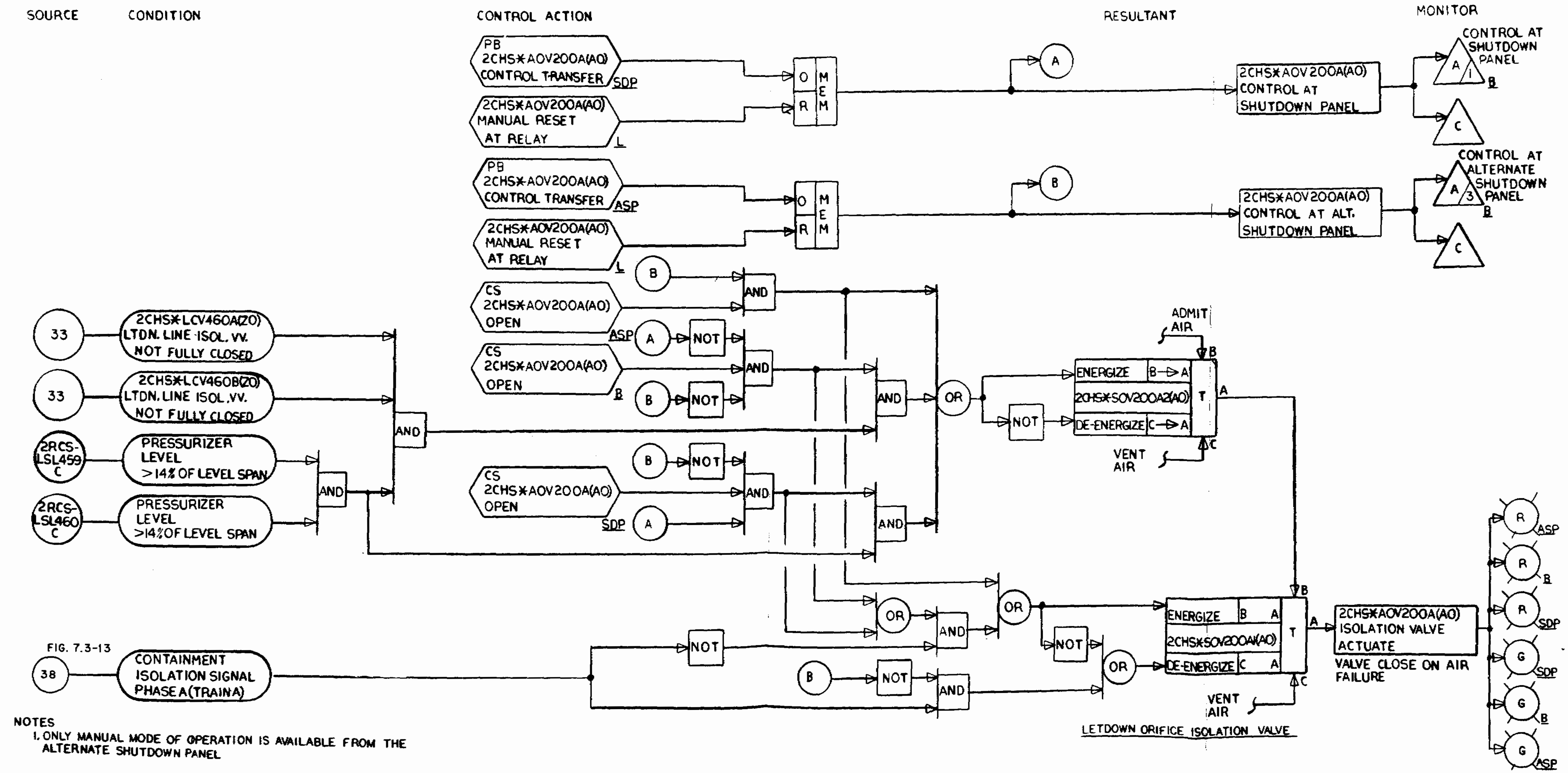


FIGURE 7.3-82
LOGIC DIAGRAM
REACTOR COOLANT SYSTEM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



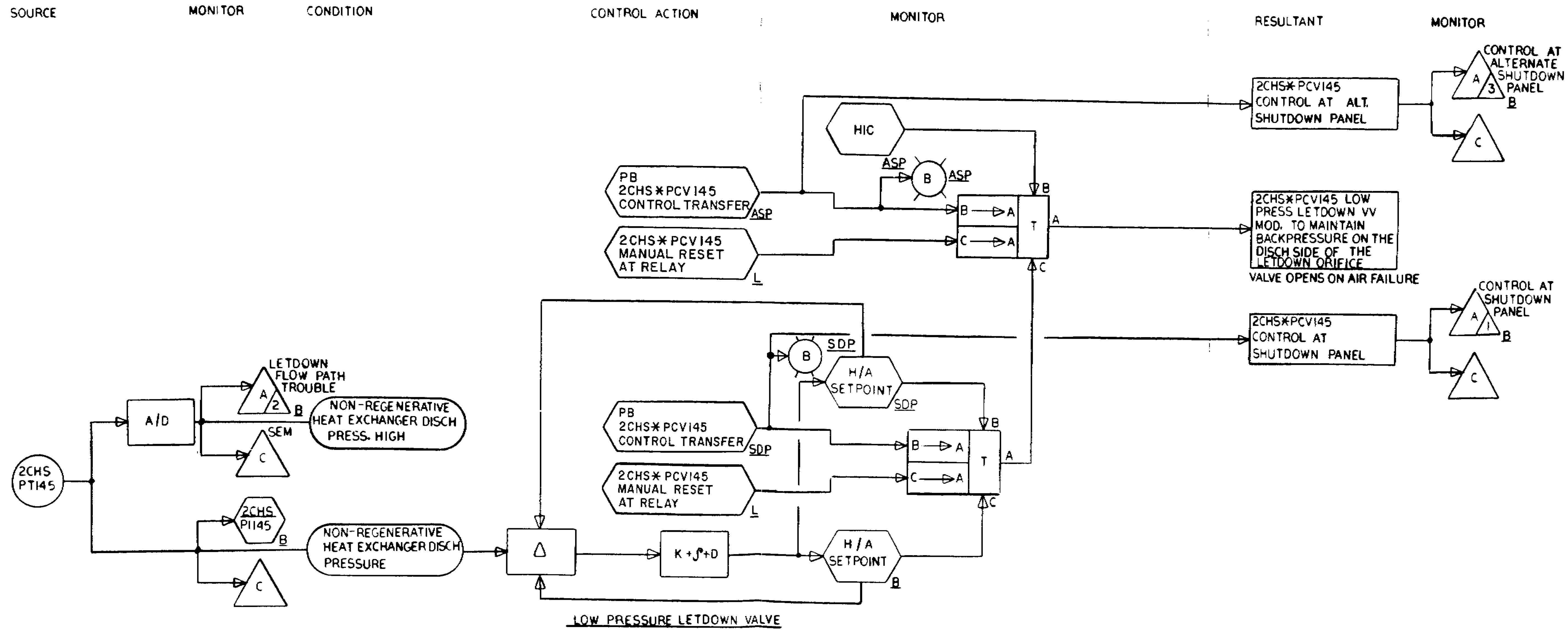
NOTES:
1. LOGIC FOR 2CHS*LCV460A(ZO) FROM ALT. SHUTDOWN PANEL SHOWN
   LOGIC FOR 2CHS*LCV460B(ZO) FROM ALT. SHUTDOWN PANEL SIMILAR
2. LOGIC FOR 2CHS*MOV100A(-O) FROM ALT. SHUTDOWN PANEL SHOWN
   LOGIC FOR 2CHS*MOV100B(-O) FROM ALT. SHUTDOWN PANEL SIMILAR
3. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL
4. LOGIC FOR 2CHS*LCV460A(ZO) AND 2CHS*LCV460B(ZO) ALSO SHOWN ON FIG 7.3-78
5. LOGIC FOR 2CHS*MOV100A(-O) AND 2CHS*MOV100B(-O) ALSO SHOWN ON FIG 7.3-81

FIGURE 7.3-82A
LOGIC DIAGRAM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES
1. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL

FIGURE 7.3-82B
LOGIC DIAGRAM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTE

1. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.

FIGURE 7.3-82C
LOGIC DIAGRAM
REACTOR COOLANT LETDOWN
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

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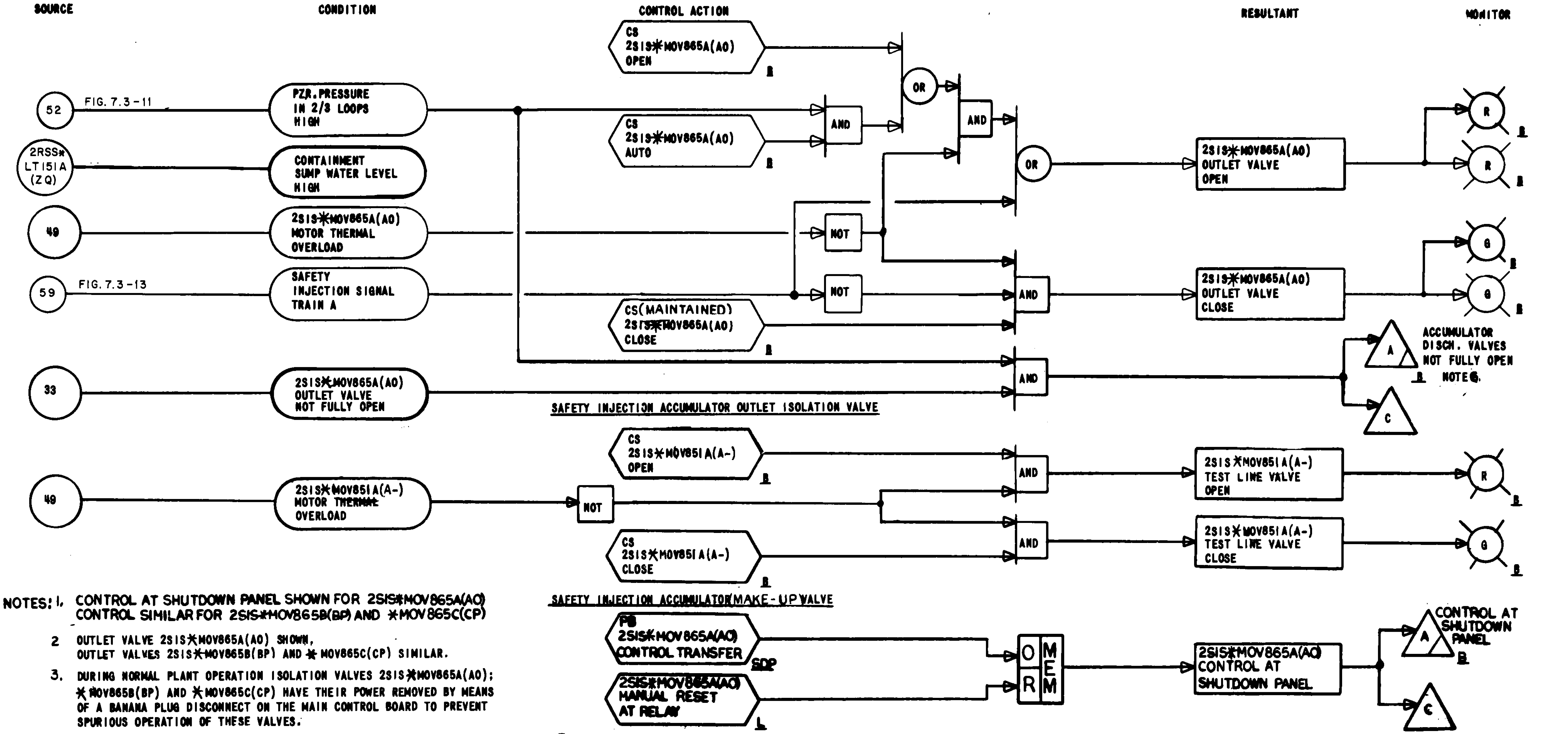

NOTES:
1. CONTROL AT SHUTDOWN PANEL SHOWN FOR 2SIS*MOV865A(AO) CONTROL SIMILAR FOR 2SIS*MOV865B(BP) AND *MOV865C(CP)
2. OUTLET VALVE 2SIS*MOV865A(AO) SHOWN, OUTLET VALVES 2SIS*MOV865B(BP) AND * MOV865C(CP) SIMILAR.
3. DURING NORMAL PLANT OPERATION ISOLATION VALVES 2SIS*MOV865A(AO); *MOV865B(BP) AND *MOV865C(CP) HAVE THEIR POWER REMOVED BY MEANS OF A BANANA PLUG DISCONNECT ON THE MAIN CONTROL BOARD TO PREVENT SPURIOUS OPERATION OF THESE VALVES.
4. MOTOR SUPPLY BREAKER IS SHUNT TRIPPED ON CONTAINMENT SUMP WATER LEVEL HIGH FOR 2SIS*MOV865A(AO), *MOV865B(BP) AND *MOV865C(CP).
5. # BY WESTINGHOUSE
6. ANNUNCIATOR WILL BE ACTUATED BY VALVE LIMIT SWITCH WHEN VALVE IS NOT FULLY OPEN AND PRZR. PRESSURE IN 2/3 LOOPS IS HIGH. THE SIGNAL WILL BE REMOVED AFTER ACKNOWLEDGMENT BUT THE WINDOW REMAINS LIGHTED UNTIL THE VALVE FULLY OPENS. A SEPARATE LIMIT SWITCH WILL REFLASH THE ANNUNCIATOR EVERY 60 MINUTES IF THE VALVE IS NOT FULLY OPEN.
7. MAKE-UP VALVE 2SIS*MOV851A(A-) SHOWN, MAKE-UP VALVES 2SIS*MOV851B(A-), MOV851C(B-), DRAIN VALVES 2SIS*MOV852A(A-), MOV852B(B-), AND MOV852C(C-) SIMILAR
8. CONTROL SWITCHES FOR 2SIS*MOV865A, B, AND C ARE SPRING RETURN FROM OPEN TO AUTO AND MAINTAINED IN CLOSED.

FIGURE 7.3-83
LOGIC DIAGRAM
SAFETY INJECTION SYSTEM
SAFETY INJECTION ACCUMULATORS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

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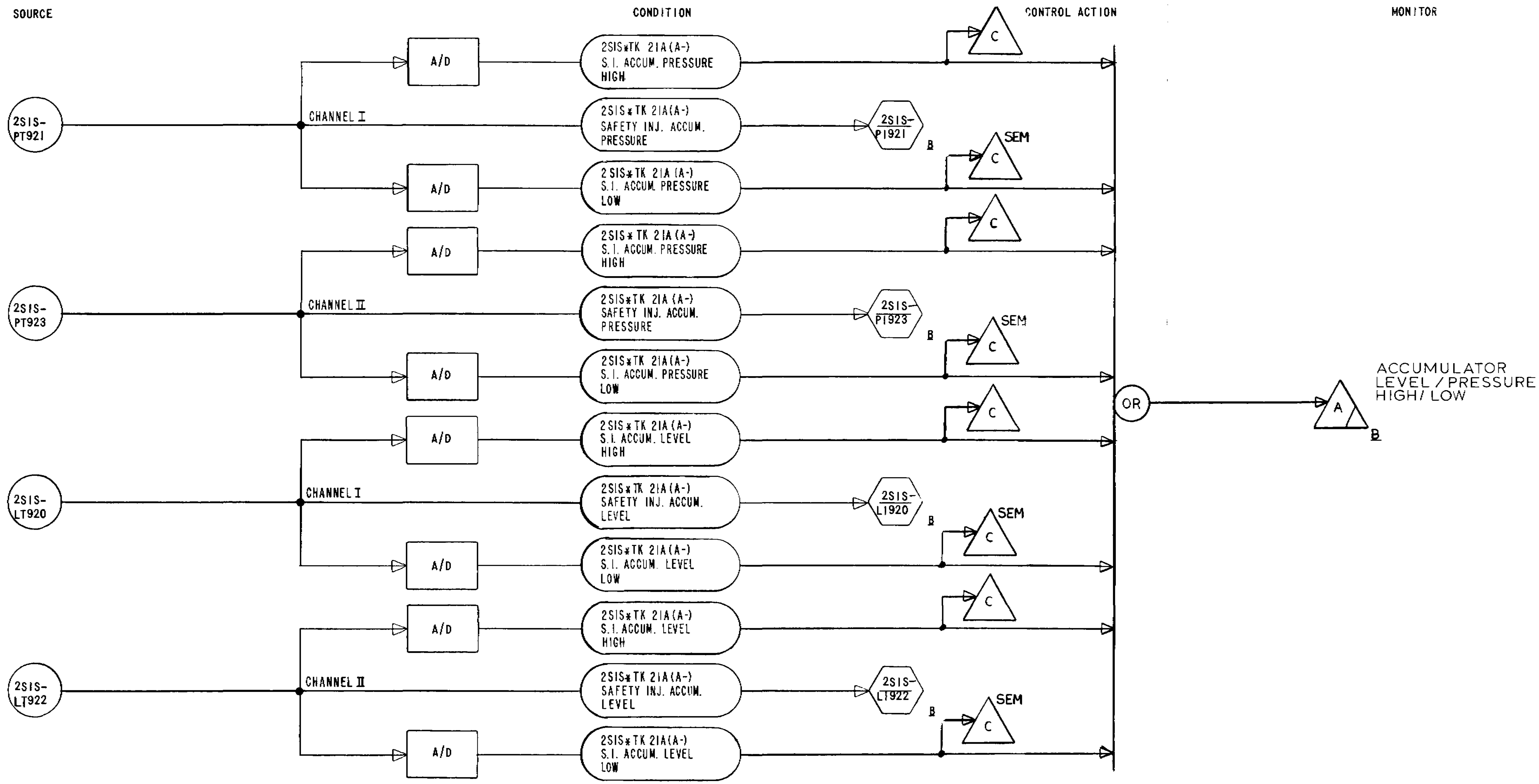
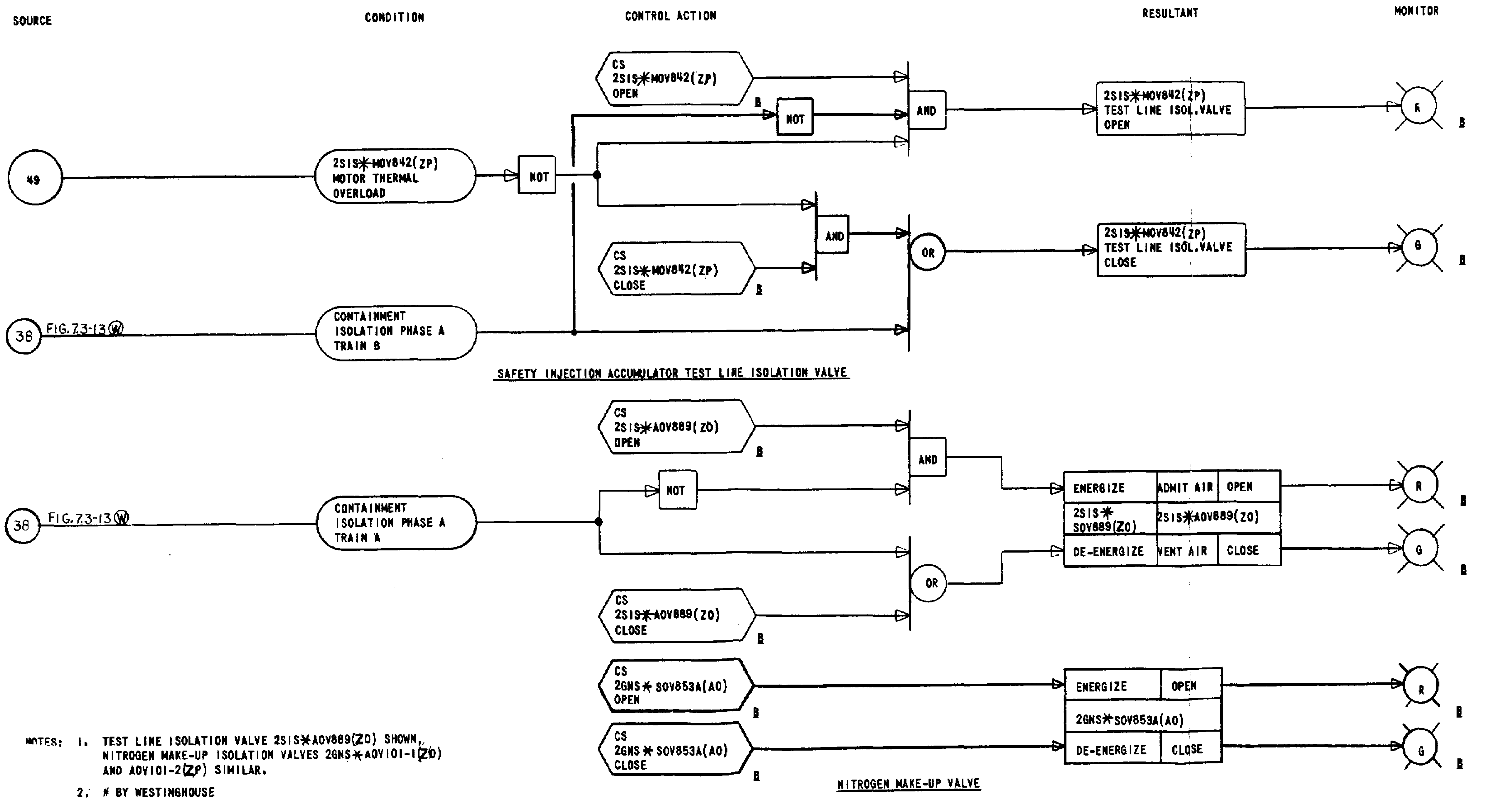


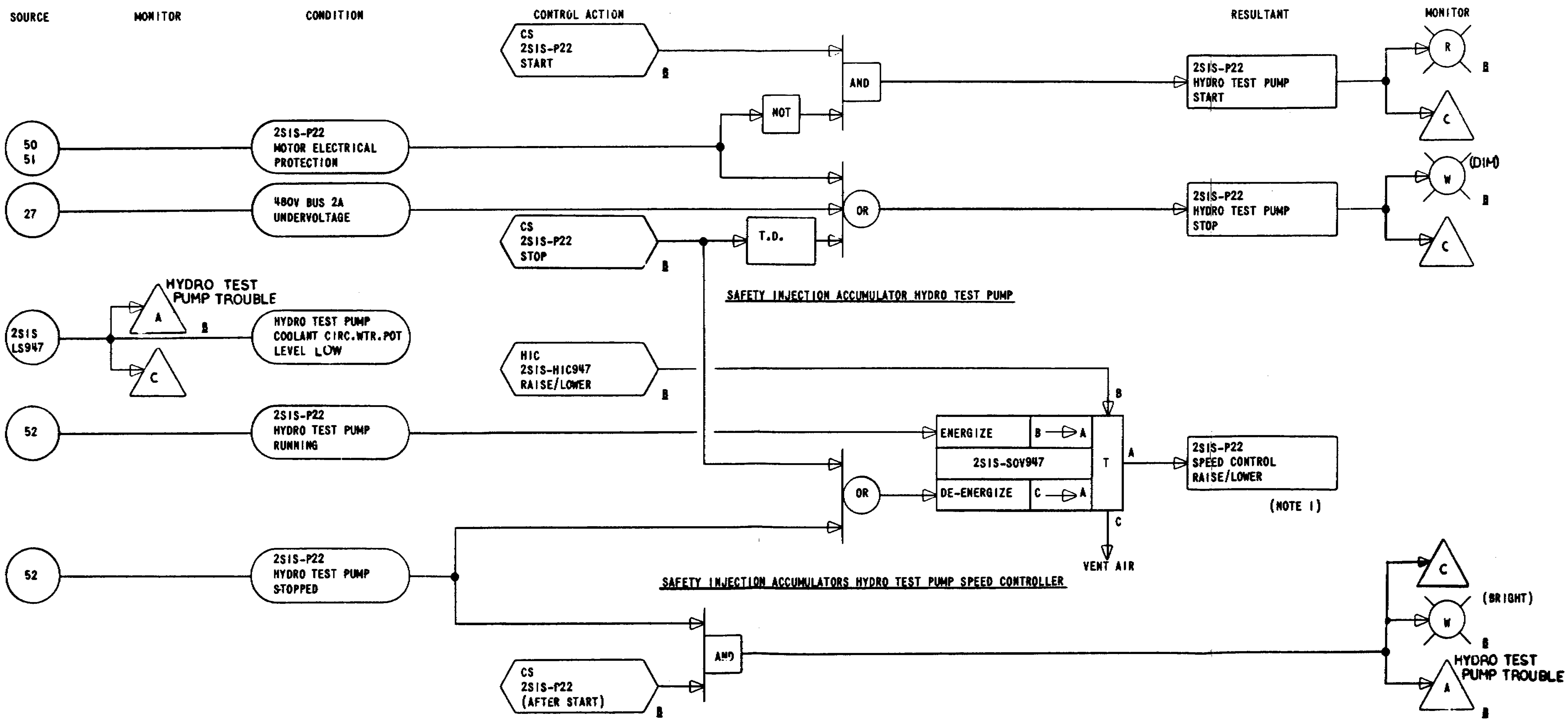
NOTES: 1. 2SIS*TK21A(A-) SHOWN.
2SIS*TK21B(B-) AND*TK21C(C-) SIMILAR.

FIGURE 7.3-84
LOGIC DIAGRAM
SAFETY INJECTION SYSTEM
SAFETY INJECTION
ACCUMULATORS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



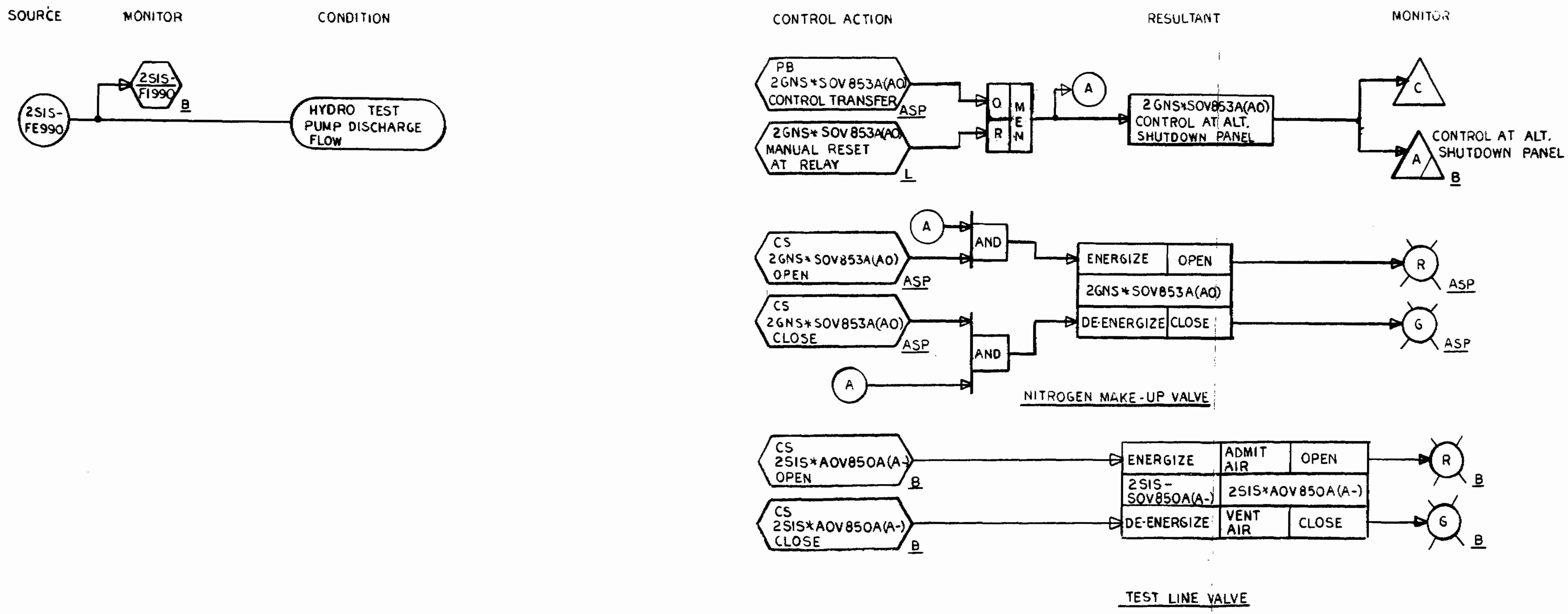
NOTES:
1. TEST LINE ISOLATION VALVE 2SIS✱AOV889(ZO) SHOWN, NITROGEN MAKE-UP ISOLATION VALVES 2GNS✱AOV101-1(ZO) AND AOV101-2(ZP) SIMILAR.
2. # BY WESTINGHOUSE
3. NITROGEN MAKE-UP VALVE 2GNS✱SOV853A(AO) SHOWN, NITROGEN MAKE-UP VALVES 2GNS✱SOV853B(BO), ✱SOV853C(CO) ✱SOV853D(AP), ✱SOV853E(BP), ✱SOV853F(CP), AND SAFETY INJECTION ACCUMULATOR VENT VALVES 2GNS✱SOV854A(AO) AND 2GNS✱SOV854B(BP) SIMILAR.

FIGURE 7.3-85
LOGIC DIAGRAM
SAFETY INJECTION SYSTEM
SAFETY INJECTION ACCUMULATORS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES: 1. VENTING SPEED CONTROL SOLENOID 2SIS-SOV947 CAUSES VARIDRIVE TO ASSUME LOWEST SPEED.

FIGURE 7.3-86
LOGIC DIAGRAM
SAFETY INJECTION SYSTEM
SAFETY INJECTION ACCUMULATORS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR 2GNS*SOV853A (AO) SHOWN. LOGIC FOR 2GNS*853B(BO), 853C(CO) AND 854A(AO) SIMILAR.
2. SEE ADDITIONAL CONTROL OF THE ABOVE SOV'S IN NOTE 1 ON FIG. 7.3-85.
3. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
4. LOGIC FOR TEST LINE VALVE 2SIS*AOV850A(A-) SHOWN. LOGIC FOR TEST LINE VALVES 2SIS*AOV850B(A-), 850C(B-), 850D(B-), 850E(C-), 850F(C-) SIMILAR.

FIGURE 7.3-86A
LOGIC DIAGRAM
SAFETY INJECTION ACCUMULATORS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

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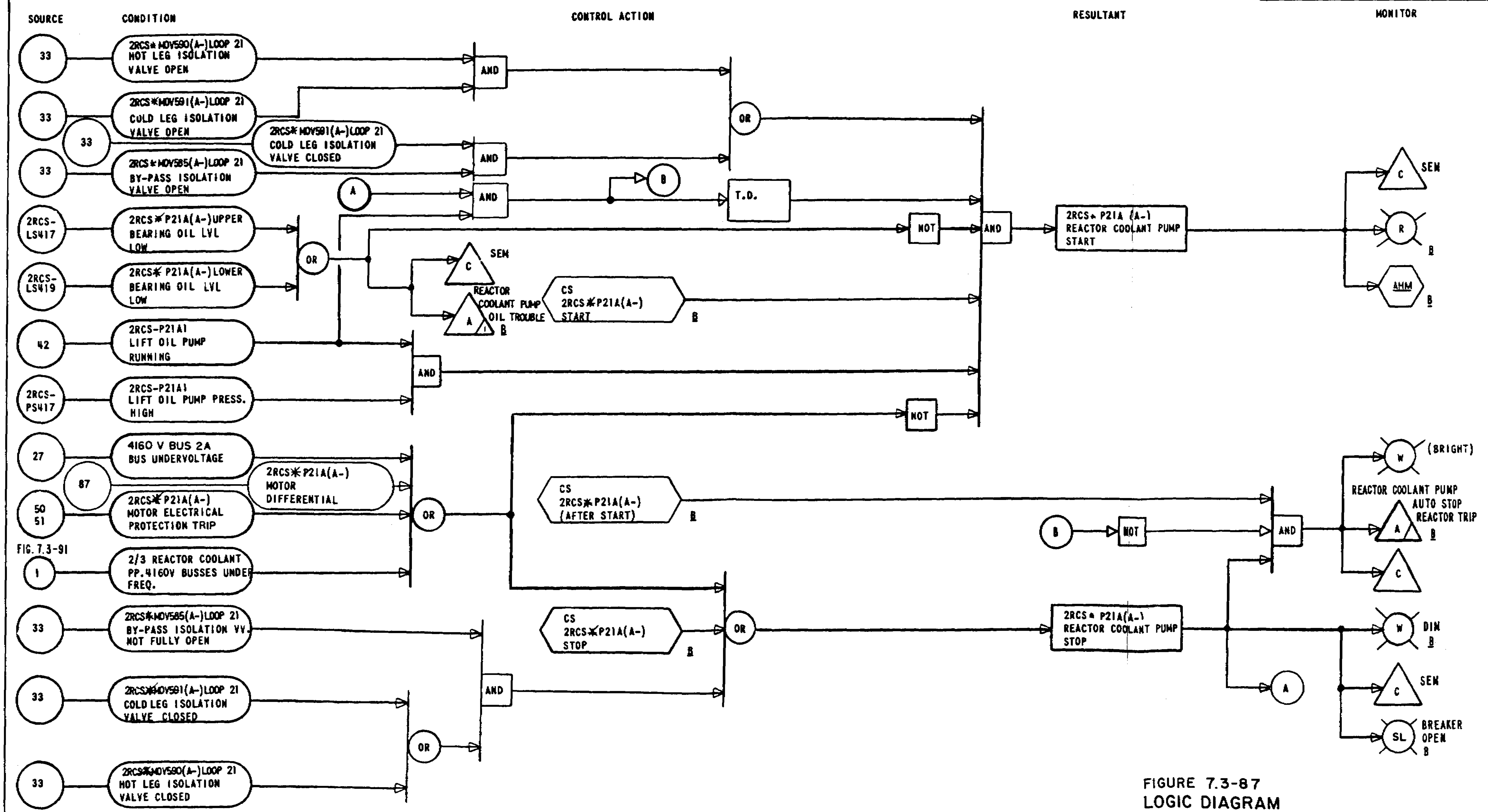
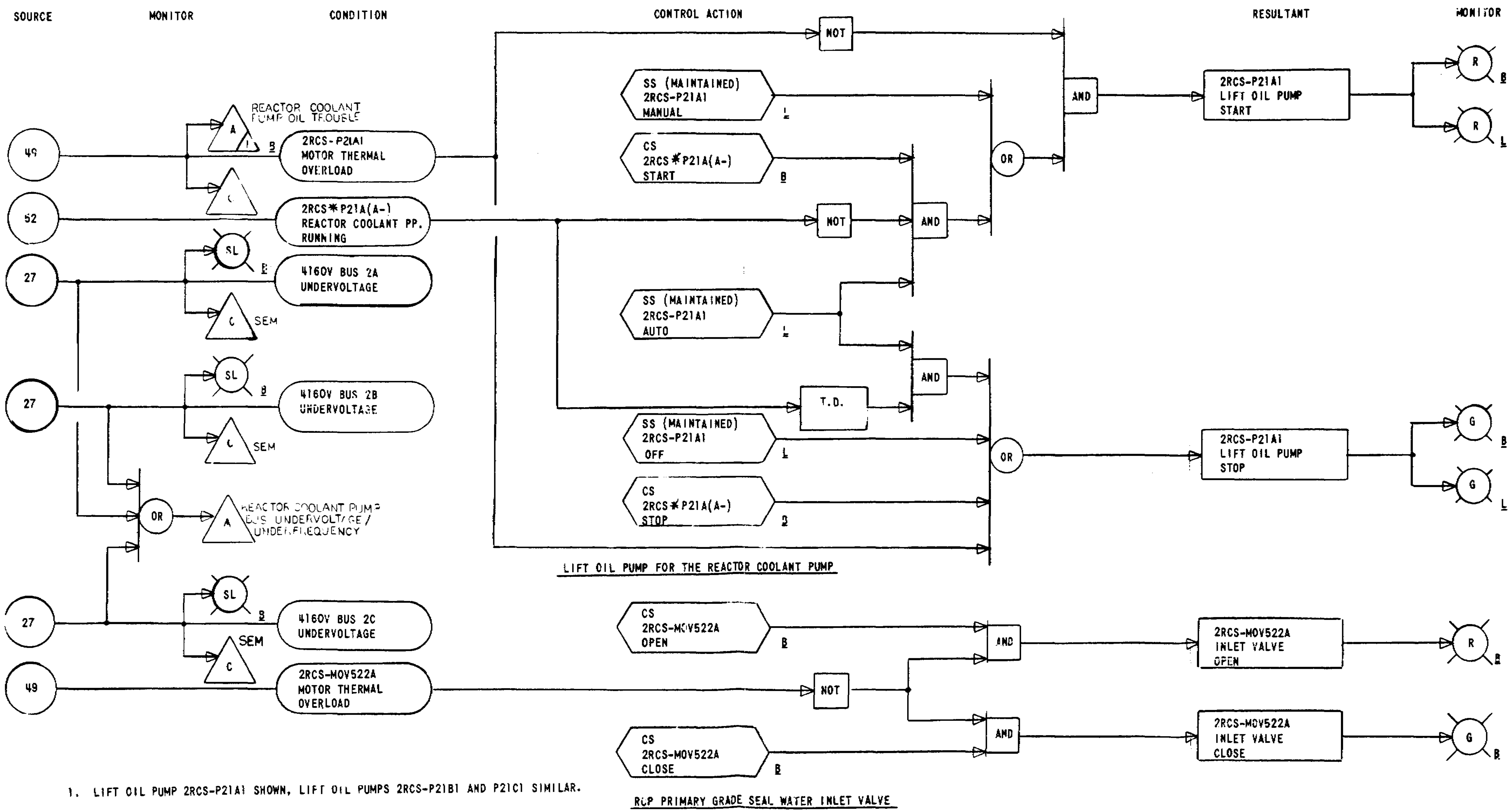


NOTE: 1. REACTOR COOLANT PUMP 2RCS*P21A(A-) IS SHOWN.
REACTOR COOLANT PUMP 2RCS*P21B(B-) AND P21C(C-) ARE SIMILAR.

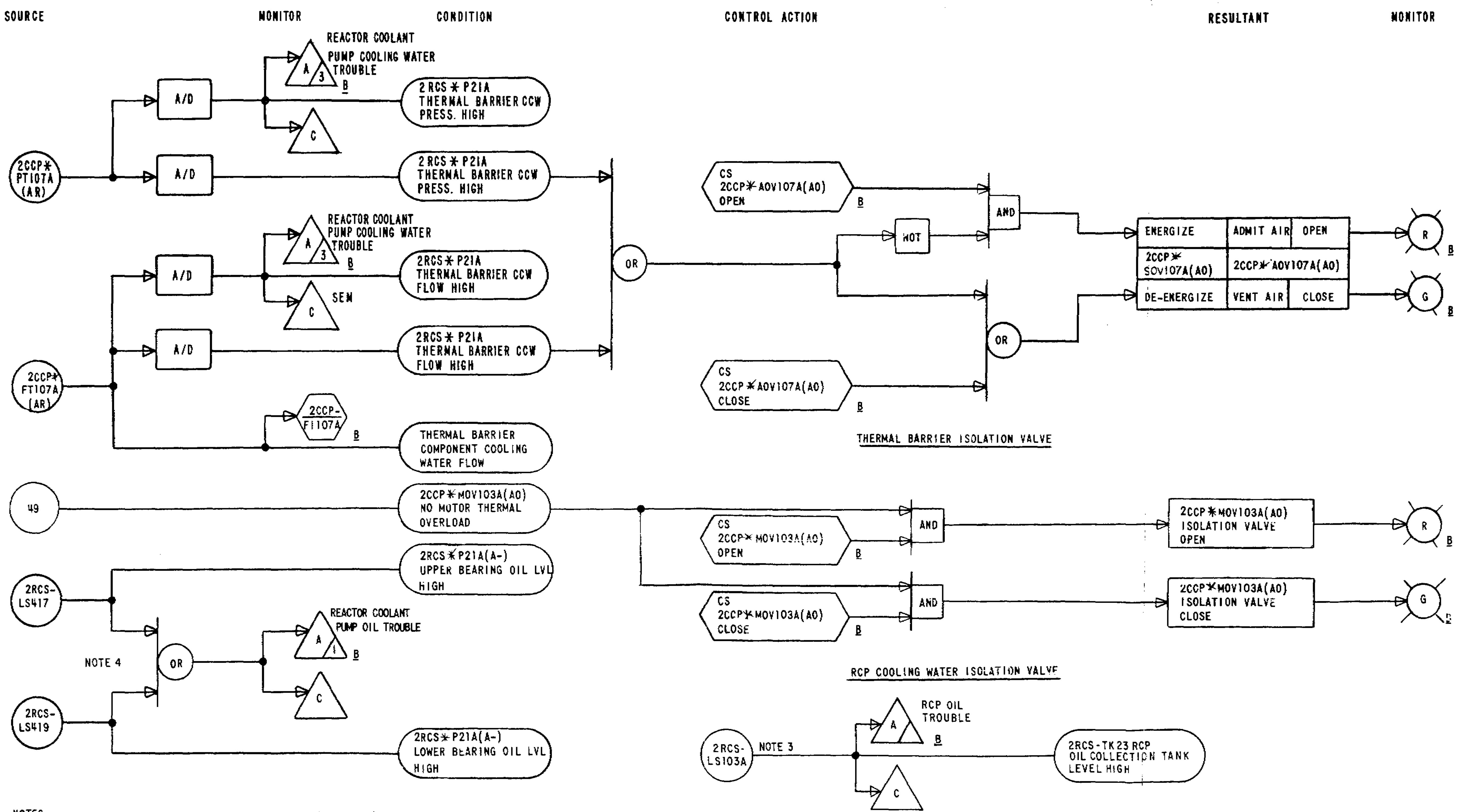
FIGURE 7.3-87
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS



1. LIFT OIL PUMP 2RCS-P21A1 SHOWN, LIFT OIL PUMPS 2RCS-P21B1 AND P21C1 SIMILAR.

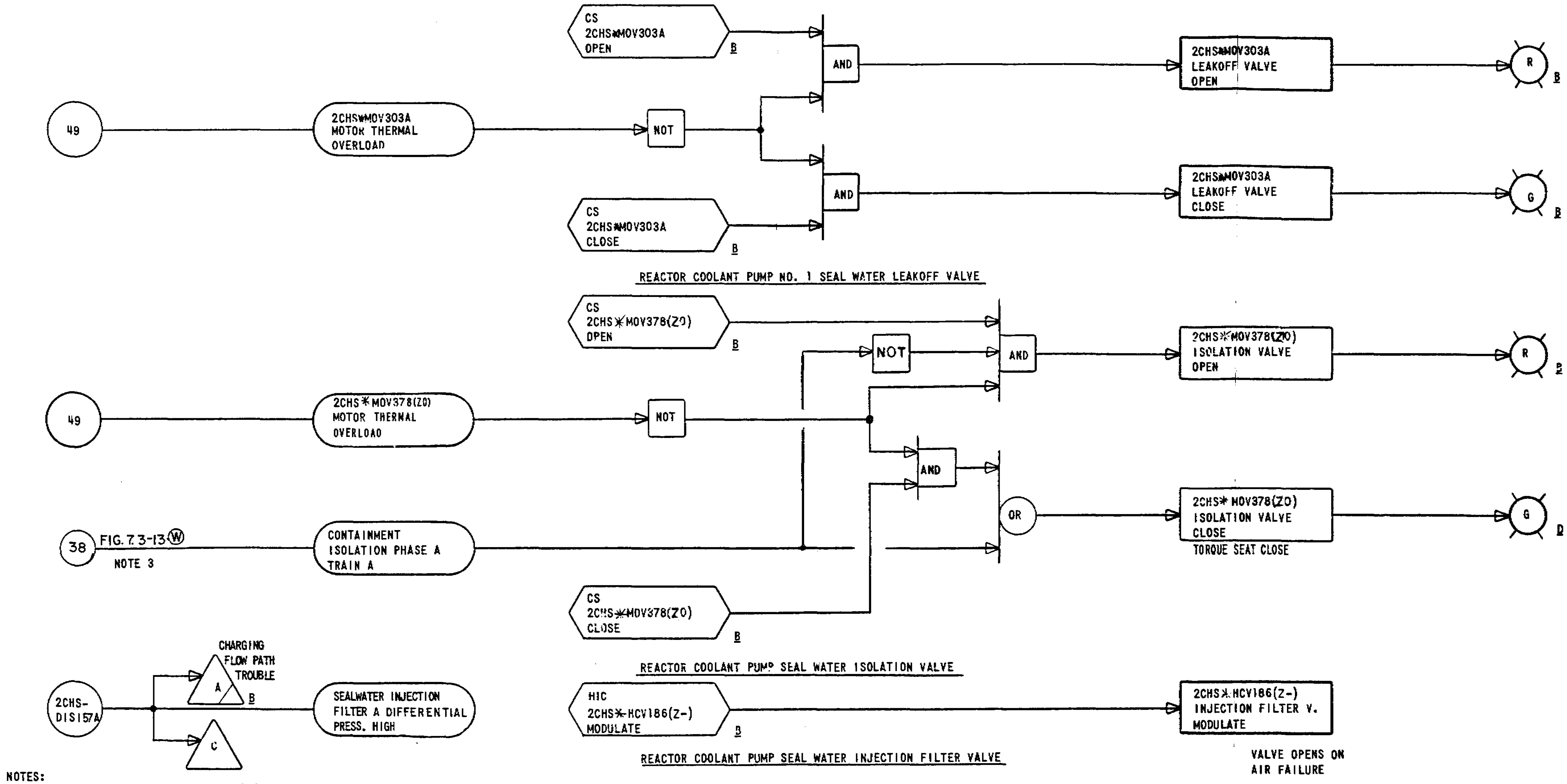
2. INLET VALVE 2RCS-MOV522A IS SHOWN, INLET VALVES 2RCS-MOV522B, AND MOV522C ARE SIMILAR.

FIGURE 7.3-88
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. THERMAL BARRIER ISOLATION VALVE 2CCP*AOV107A(AO) IS SHOWN. THERMAL BARRIER ISOLATION VALVES 2CCP*AOV107B(BP) AND AOV107C(BP) ARE SIMILAR.
2. RCP BEARINGS COOLING WATER ISOLATION VALVE 2CCP*MOV103A(AO) IS SHOWN. RCP BEARINGS COOLING WATER ISOLATION VALVES 2CCP*MOV103B(BP) AND MOV103C(BP) ARE SIMILAR.
3. LOGIC FOR 2RCS-LS103A SHOWN, LOGIC FOR 2RCS-LS103B AND C IS SIMILAR.
4. LOGIC FOR 2RCS-LS417 AND LS419 SHOW FOR 2RCS*P21A, LOGIC FOR 2RCS-LS427/429 FOR 2RCS*P21B AND 2RCS-LS437/439 FOR 2RCS*P21C SIMILAR.

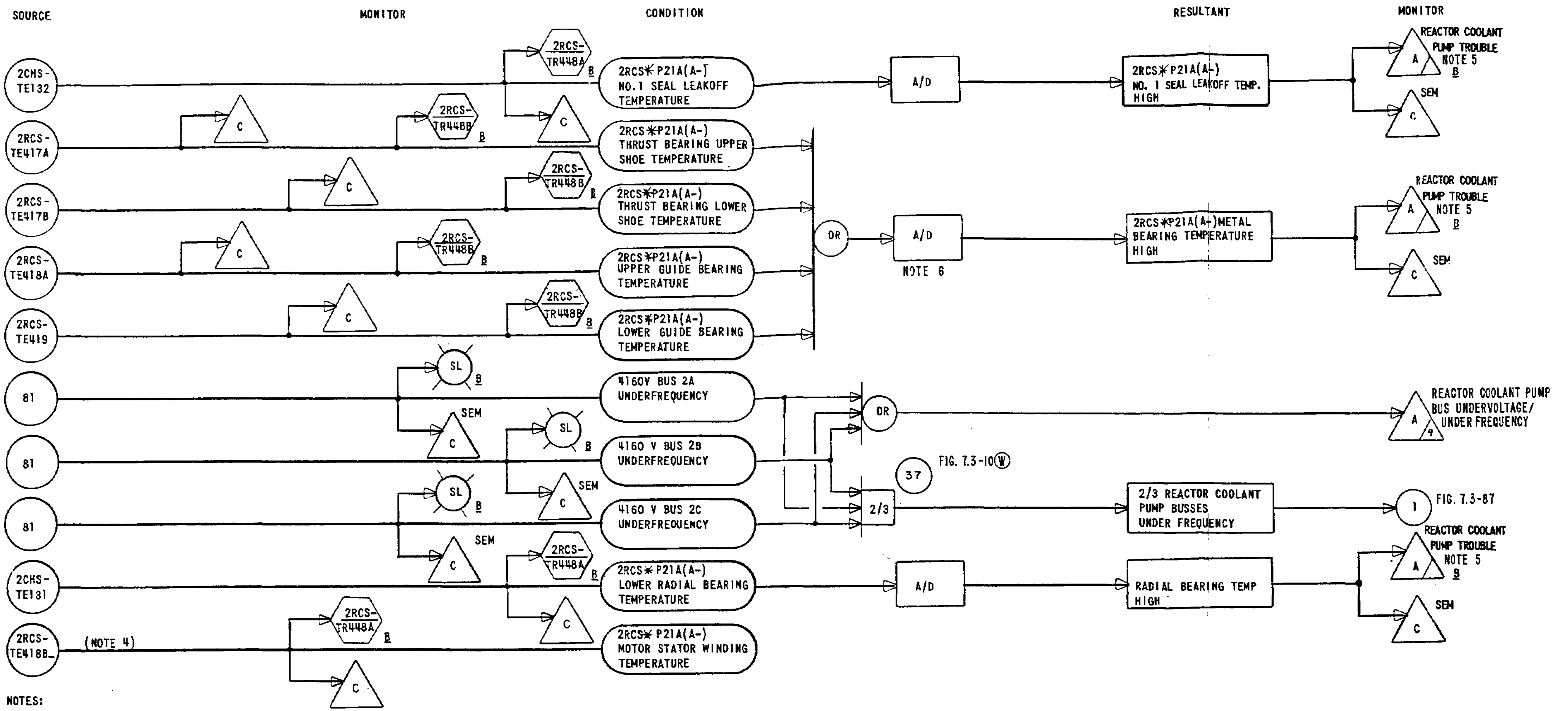
FIGURE 7.3-89
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LEAKOFF VALVE 2CHS*MOV303A SHOWN, LEAKOFF VALVES 2CHS*MOV303B, AND MOV*303C ARE SIMILAR
2. ISOLATION VALVE 2CHS*MOV378(ZO) SHOWN, ISOLATION VALVE 2CHS*MOV381(ZP) SIMILAR.
3. # BY WESTINGHOUSE.
4. 2CHS-DIS157A SHOWN. 2CHS-DIS157B SIMILAR.

FIGURE 7.3-90
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. REACTOR COOLANT PUMP 2RCS*P21A(A-) MONITORING DEVICES SHOWN. REACTOR COOLANT PUMPS 2RCS*P21B(B-) AND P21C(C-) MONITORING DEVICES SIMILAR.

2. UNDERFREQUENCY STATUS LIGHTS, COMPUTER INPUTS, AND ANNUNCIATORS, INPUTS ARE COMMON TO BOTH TRAINS (NOT SHOWN).

3. REACTOR COOLANT PUMP ASSOCIATED EQUIPMENT MARK NUMBERS:

2RCS*P21A(A-)	2RCS*P21B(B-)	2RCS*P21C(C-)	RECORDER
2CHS-TE132	2CHS-TE129	2CHS-TE126	2RCS-448A
2CHS-TE131	2CHS-TE128	2CHS-TE125	2RCS-448A
2RCS-TE418B	2RCS-TE428B	2RCS-TE438B	2RCS-448A
2RCS-TE417A	2RCS-TE427A	2RCS-TE437A	2RCS-448B
2RCS-TE417B	2RCS-TE427B	2RCS-TE437B	2RCS-448B
2RCS-TE418A	2RCS-TE428A	2RCS-TE438A	2RCS-448B
2RCS-TE419	2RCS-TE429	2RCS-TE439	2RCS-448B

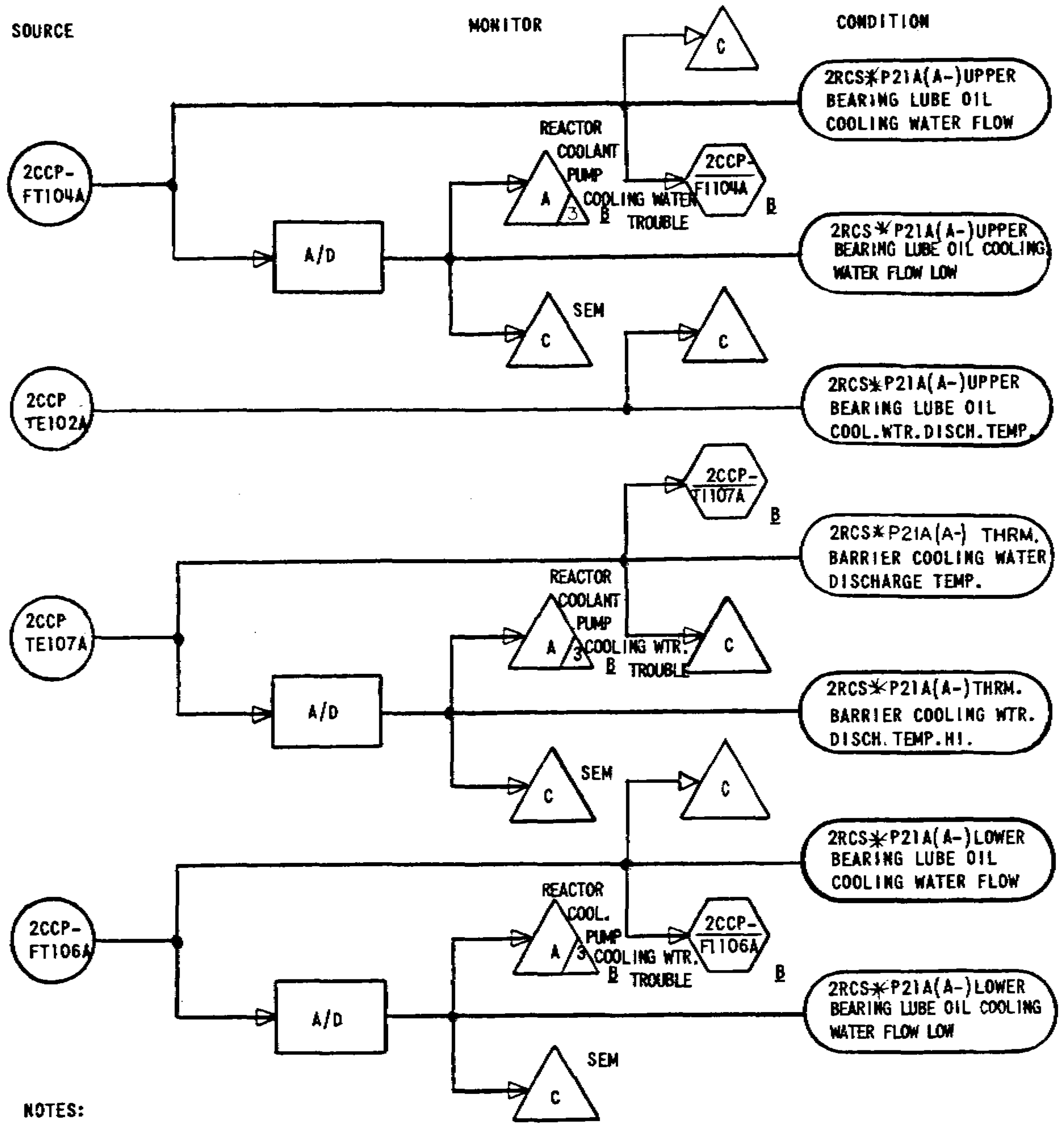
4. EACH REACTOR COOLANT PUMP MOTOR IS SUPPLIED WITH SIX RTD'S. ONE IS USED FOR COMPUTER INPUT, ONE FOR RECORDER INPUT AND ONE FOR ELECTRICAL PROTECTION. THREE ARE SPARES.

2RCS-P21A	2RCS-TE418B1, 2, 3, 4, 5, 6
2RCS-P21B	2RCS-TE428B1, 2, 3, 4, 5, 6
2RCS-P21C	2RCS-TE438B1, 2, 3, 4, 5, 6

5. ANNUNCIATOR SETPOINT GENERATED BY RECORDER.

6. PUMPS 2RCS*P21A, P21B, AND P21C UTILIZE COMMON RECORDER GENERATED SETPOINT.

FIGURE 7.3-91
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. REACTOR COOLANT PUMP 2RCS*P21A(A-) MONITORING DEVICES SHOWN.
   REACTOR COOLANT PUMP 2RCS*P21B(B-) AND P21C(C-) MONITORING DEVICES SIMILAR.

2. REACTOR COOLANT PUMPS ASSOCIATED EQUIPMENT MARK NUMBERS:

2RCS* P21A(A-)	2RCS* P21B(B-)	2RCS* P21C(C-)
2CCP-TE102A	2CCP-TE102B	2CCP-TE102C
2CCP-TE103A	2CCP-TE103B	2CCP-TE103C
2CCP-TE104A	2CCP-TE104B	2CCP-TE104C
2CCP-FT104A	2CCP-FT104B	2CCP-FT104C
2CCP-TE105A	2CCP-TE105B	2CCP-TE105C
2CCP-FT105A	2CCP-FT105B	2CCP-FT105C
2CCP-FT106A	2CCP-FT106B	2CCP-FT106C
2CCP-TE107A	2CCP-TE107B	2CCP-TE107C

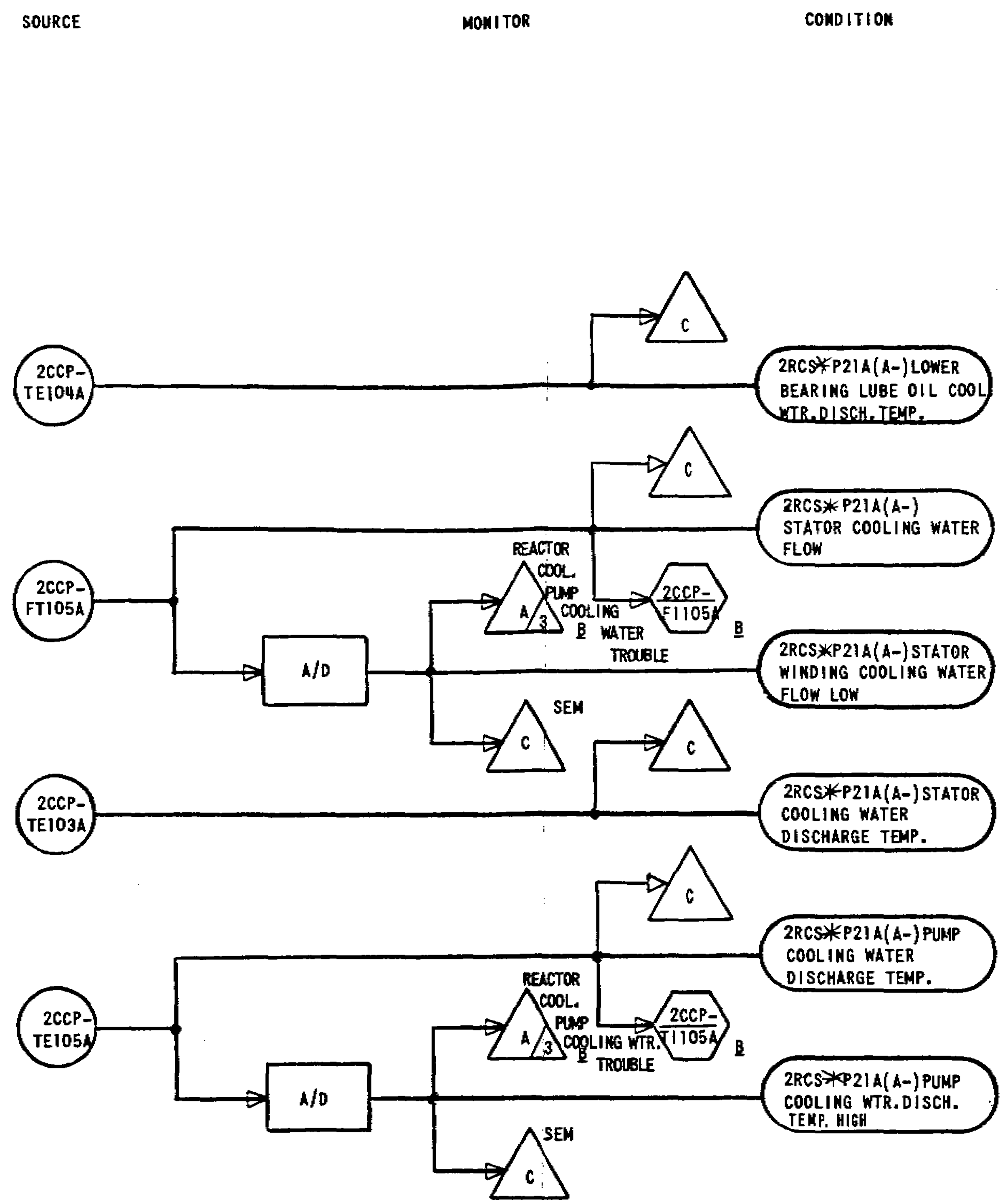
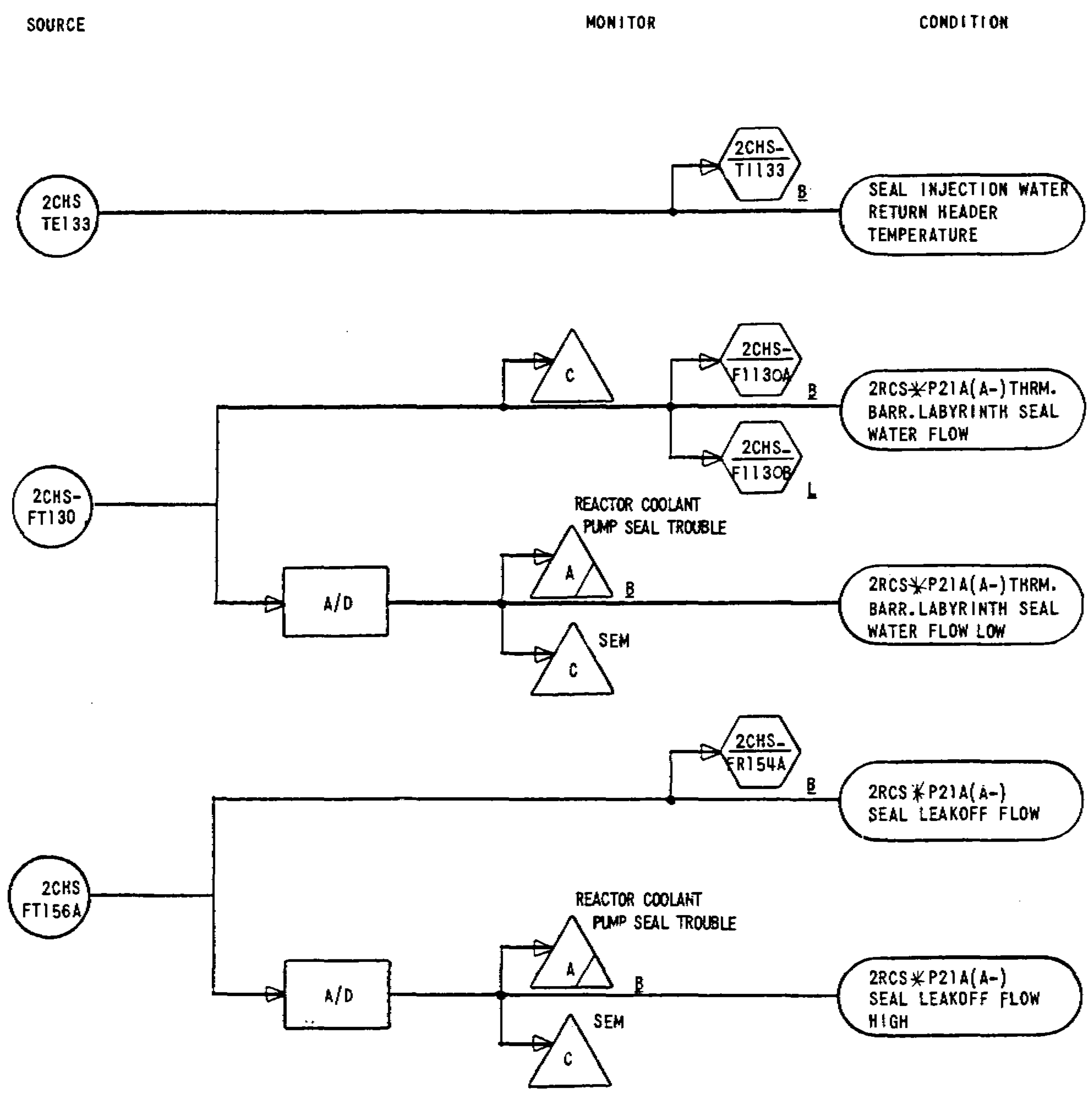
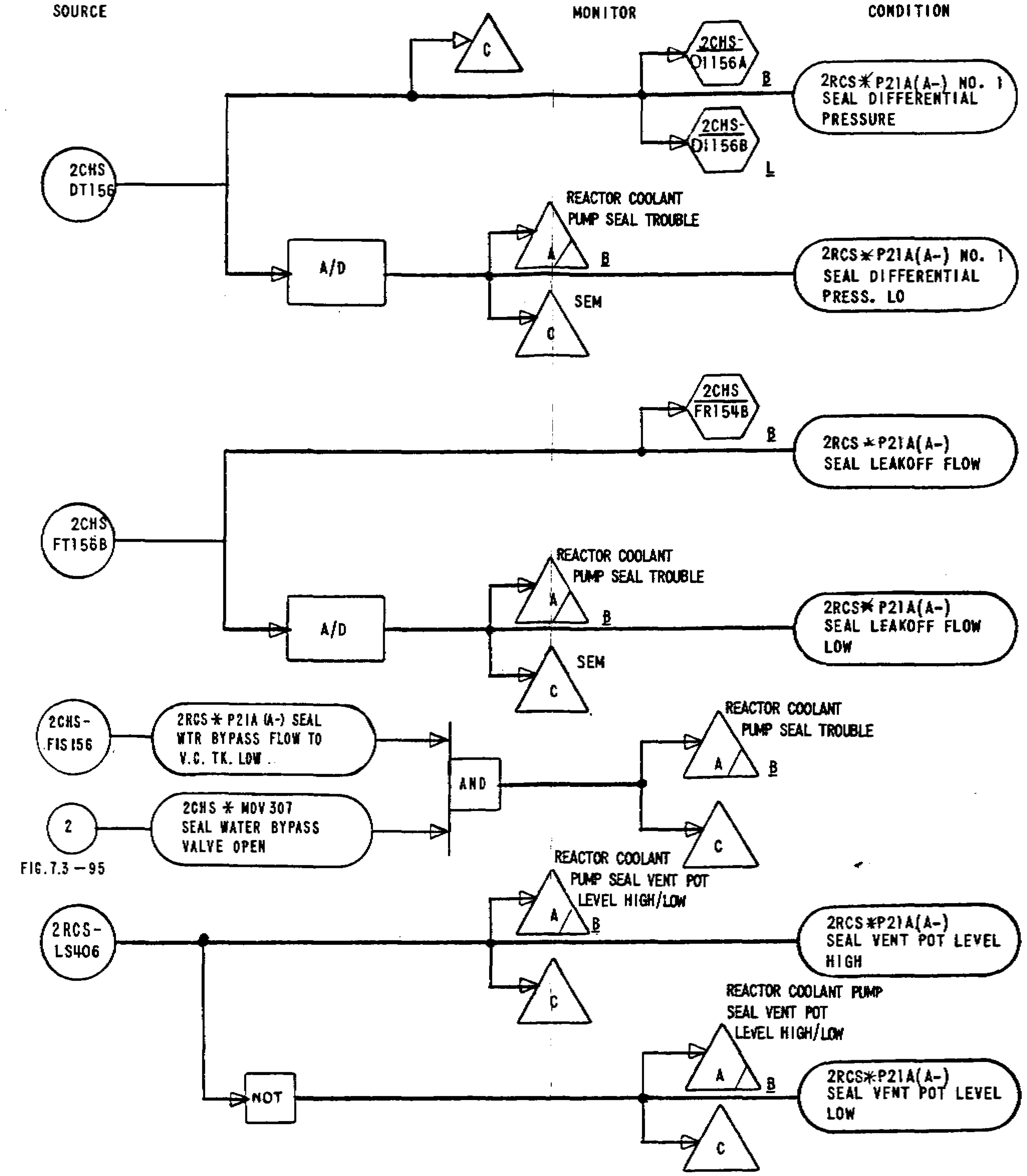


FIGURE 7.3-92
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT





NOTES:

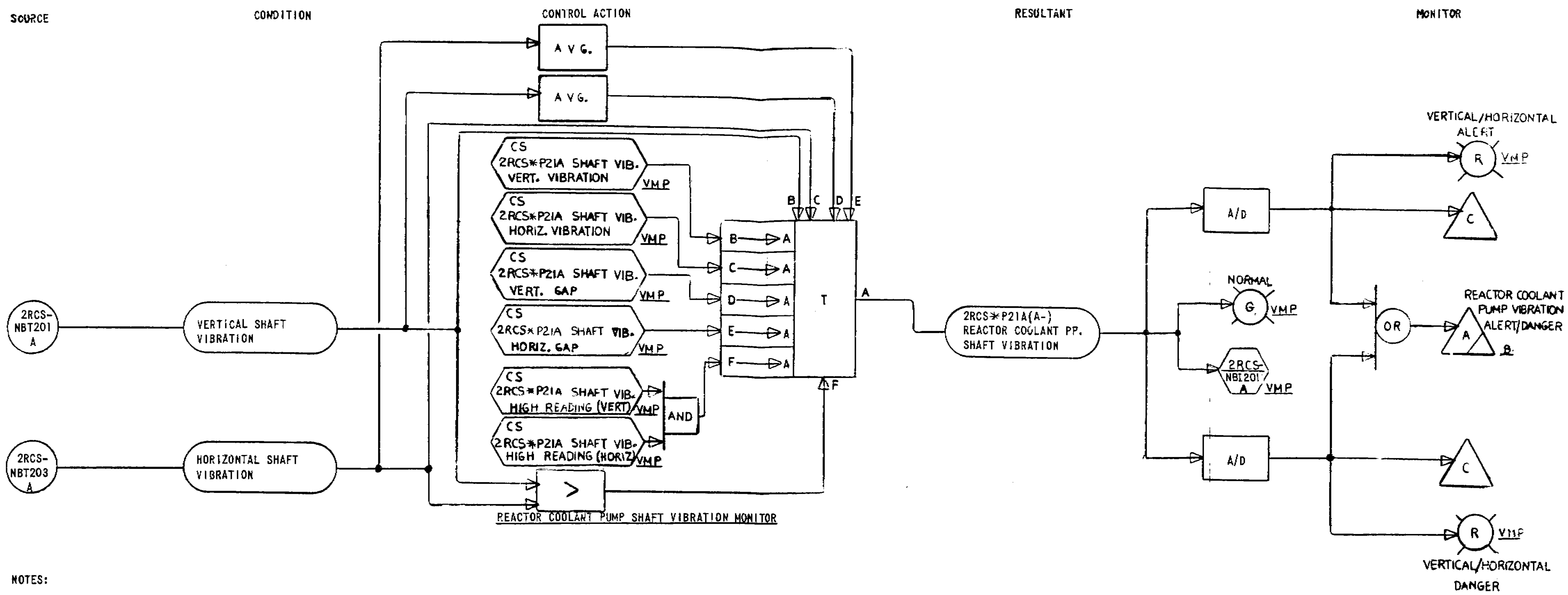
1. REACTOR COOLANT PUMP 2RCS✱P21A(A-) MONITORING DEVICES SHOWN. REACTOR COOLANT PUMP 2RCS✱P21B(B-) AND P21C(C-) MONITORING DEVICES SIMILAR.

2. REACTOR COOLANT PUMPS ASSOCIATED EQUIPMENT MARK NUMBERS:

2RCS✱P21A(A-)	2RCS✱P21B(B-)	2RCS✱P21C(C-)
2CHS-FT130	2CHS-FT127	2CHS-FT124
2CHS-FT156A	2CHS-FT155A	2CHS-FT154A
2CHS-FT156B	2CHS-FT155B	2CHS-FT154B
2CHS-DT156	2CHS-DT155	2CHS-DT154
2CHS-FIS156	2CHS-FIS155	2CHS-FIS154
2RCS-LS406	2RCS-LS407	2RCS-LS408

FIGURE 7.3-93
LOGIC DIAGRAM
REACTOR COOLANT PUMPS

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. 2RCS*P21A(A-) SHAFT VIBRATION MONITOR SHOWN.
2RCS*P21A(A-) FRAME VIBRATION MONITOR, 2RCS*P21B(B-) SHAFT AND FRAME VIBRATION MONITORS AND 2RCS*P21C(C-) SHAFT AND FRAME VIBRATION MONITORS ARE SIMILAR.

2. VIBRATION MONITORS ASSOCIATED EQUIPMENT MARK NUMBERS:

	2RCS*P21A(A-)	2RCS*P21B(B-)	2RCS*P21C(C-)	
VERTICAL HORIZONTAL	2RCS-NBI201A 2RCS-NBT201A 2RCS-NBT203A	2RCS-NBI201B 2RCS-NBT201B 2RCS-NBT203B	2RCS-NBI201C 2RCS-NBT201C 2RCS-NBT203C	SHAFT
VERTICAL HORIZONTAL	2RCS-NBI202A 2RCS-NBT202A 2RCS-NBT204A	2RCS-NBI202B 2RCS-NBT202B 2RCS-NBT204B	2RCS-NBI202C 2RCS-NBT202C 2RCS-NBT204C	FRAME

3. A KEY PHASOR PROBE 2RCS-NBE205A, B, & C IS PROVIDED FOR EACH REACTOR PUMP WHICH IS REQUIRED FOR INITIAL AND ANY SUBSEQUENT BALANCING.

4. VMP - VIBRATION MONITORING PANEL IS LOCATED IN THE CONTROL ROOM.

5. A MANUAL RESET IS LOCATED ON THE VIBRATION MONITOR PANEL FOR EACH VIBRATION MONITOR.

FIGURE 7.3-94
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

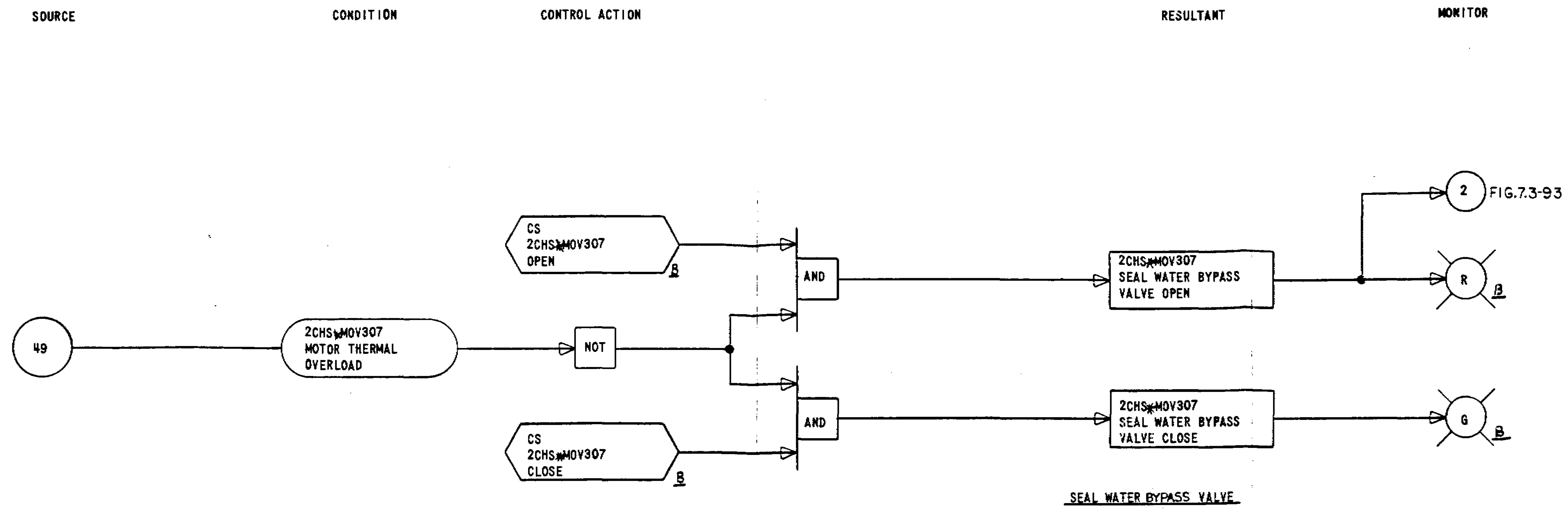


FIGURE 7.3-95
LOGIC DIAGRAM
REACTOR COOLANT PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown are available from instrumentation channels that are associated with the major primary and secondary systems of the nuclear steam supply. These channels are normally aligned to serve a variety of operational functions, including start-up end shutdown as well as protective functions. However, procedures for securing and maintaining Beaver Valley Power Station - Unit 2 (BVPS-2) in a safe condition can be instituted by appropriate alignment of selected components in the nuclear steam supply. The discussion of these systems, together with the applicable codes, criteria, and guidelines, is found in other sections of this safety analysis report. In addition, the alignment of shutdown functions associated with the engineered safety features, which are invoked under postulated limiting fault situations, is discussed in Chapter 6 and Section 7.3.

Two kinds of shutdown conditions, both capable of being achieved with or without offsite power, are addressed in this section: hot standby and cold shutdown. Hot standby is a stable condition of the reactor achieved shortly after a programmed or emergency shutdown of BVPS-2. Although hot standby is the safe shutdown design basis for BVPS-2, safety grade provisions have been incorporated in the design of the plant to facilitate cold shutdown. Cold shutdown is a stable condition of the plant achieved after the residual heat removal (RHR) process has brought the primary coolant temperature below 200°F. For a description of the RHR system and how it is used for cold shutdown, refer to Section 5.4.7.

For either case of the safe shutdown, that is, hot standby or cold shutdown, the reactivity control systems maintain a subcritical condition of the core. The plant Technical Specifications explicitly define both hot standby and cold shutdown conditions. The electrically-powered instrumented and controlled systems and equipment which are required to be aligned for achieving and maintaining cold shutdown without offsite power, with main control room occupancy, with a single random failure, and with limited operator action outside of the control room are a minimum set listed as follows. These systems and equipment are available from inside the main control room:

1. Emergency, vital electrical power supply,*

2. Auxiliary feedwater system (AFWS),*

3. Residual heat removal (and isolation) system,

4. Borated water inventory supply to centrifugal charging pump suction via the emergency boration path and the boric acid transfer pump, which takes suction directly from the boric acid tank through a normally open path when the emergency boration valve is opened. In addition, there is an alternate source of boration supplied to the charging pump suction from the refueling water storage tank,

5. Redundant discharge system from the centrifugal charging pumps, both having throttling capability through safety injection lines,

6. Power operated relief valves (PORVs) for reactor coolant system (RCS),

7. Pressurizer safety valves,*

8. Decay heat removal, using steam line atmospheric dump valves (ADVs) and limited operator action, as well as steam generator safety valves,*

9. Safety grade head vent letdown to pressurizer relief tank isolation system, which will withstand an active failure,

10. Reactor protection system,* and

11. Redundant accumulator isolation venting, in addition to the normal isolation valves.

*The minimum number of instrumentation and control functions permitted under nonaccident conditions, which are required to be aligned for maintaining hot standby. They are available outside as well as inside the main control room, and accomplish the following functions:

1. Prevent the reactor from achieving criticality in violation of the Technical Specifications,

2. Provide an adequate heat sink such that design and safety limits are not exceeded,

3. Pressurizer pressure control, and

4. Provide RCS inventory control.

7.4.1 Description

Instrumentation and control provisions associated with the hot standby systems are identified in Sections 7.4.1.1 and 7.4.1.2. The equipment and services for cold shutdown are identified in Section 7.4.1.4. Loss of the monitoring instrumentation and local controls outside the main control room and normal automatic systems are not assumed coincident with control room evacuation. For applicable drawings, refer to Section 1.7.

7.4.1.1 Monitoring Indicators

The characteristics of these indicators, which are provided outside as well as inside the main control room, are described in Section 7.5. The necessary indicators are as follows:

1. Water level indicator (wide range) for each steam generator,

2. Pressure indicator for each steam generator,

3. Pressurizer water level indicator, and

4. Pressurizer or RCS pressure indicator.

The remote shutdown monitoring instrumentation channels, with readouts displayed external to the control room, are shown in Table 7.4-3.

7.4.1.2 Controls

7.4.1.2.1 General Considerations

1. The turbine is tripped (Note that this can be accomplished at the turbine as well as in the main control room). This closes the turbine steam stop valves.

2. The reactor is tripped (Note that this can be accomplished at the reactor trip switchgear as well as in the main control room).

3. All automatic systems continue functioning (discussed in Section 7.7).

4. Selected controls for safe shutdown are located inside as well as outside the main control room. Those controls located outside the control room are provided with a control transfer pushbutton which transfers control from the main control room to the emergency shutdown panel (ESP). Placing the pushbutton in the local operating position is annunciated inside the main control room.

7.4.1.2.2 Pumps and Compressors

1. Auxiliary feedwater pumps

   In the event of feedwater pump stoppage due to a loss of electrical power, the auxiliary feedwater pumps start automatically. The pumps can be started manually at the ESP as well as inside the main control room.

2. Charging pumps

   Start/stop motor controls for these pumps are located on the ESP as well as inside the main control room.

3. Boric acid transfer pumps

   Start/stop motor controls for these pumps are located on the ESP as well as inside the main control room.

4. Service water pumps

   Start/stop motor controls for these pumps are located on the ESP as well as inside the main control room.

5. Component cooling water pumps

   Start/stop motor controls for these pumps are located on the ESP as well as inside the main control room.

6. Instrument air compressors

   These compressors start automatically on low air pressure. However, loss of instrument air does not prevent the operation of the minimum systems necessary for hot standby.

7.4.1.2.3 Emergency Diesel Generators

These units start automatically following a loss of normal ac power. Manual controls for emergency diesel generator start-up are also provided locally at the diesel generators as well as inside the main control room.

7.4.1.2.4 Valves and Heaters

1. Charging flow control valves

   Charging flow control valves fail open upon loss of instrument air. Subsequent control of the flow can be maintained through control of the charging pumps at the ESP.

2. Letdown orifice isolation valves

   Manual control is provided both at the ESP and inside the main control room.

3. Auxiliary feedwater control valves

   Controls for these valves are located at the ESP and inside the main control room.

4. Steam generator safety valves and steam line atmospheric dump valves

   a. Spring-loaded safety valves

      The safety relief valves on each steam header are located upstream of the isolation valves. They are spring-loaded, self-opening on an increase in pressure in the steam header.

   b. Atmospheric dump valves

      The ADVs are located upstream of the isolation valves, one on each steam header. Control of these valves is automatic by steam line pressure, with remote manual control by adjustment of the pressure set point from the main control room as well as at the ESP. In addition, local manual operators are provided in the event of complete loss of automatic control.

5. Pressurizer heater control

   On-off control with selector switches is provided for two backup heater groups at the ESP. The heater groups are connected to separate buses, such that each group can be powered from separate emergency diesel generators in the event of loss of offsite power (LOOP). The controls are grouped with the charging flow controls at the ESP and duplicate functions are available in the main control room.

7.4.1.3 Main Control Room Evacuation

The instrumentation and controls listed in Sections 7.4.1.1 and 7.4.1.2, which are used to achieve and maintain a safe shutdown, are available in the event an evacuation of the main control room is required. These controls and instrumentation channels, together with the equipment and systems listed in Section 7.4.1.4, identify the potential capability for cold shutdown of the reactor subsequent to a main control room evacuation through the use of suitable procedures. Control room evacuation shall not occur coincident with an abnormal operating condition (Condition II, III, or IV event) except the loss of offsite power. The emergency shutdown panel and the equipment used to maintain remote shutdown fulfill the single failure criterion. Normal control from the main control room would normally be expected to function under all conceivable events.

In accordance with General Design Criterion (GDC) 19, provisions are made to control certain vital systems required for hot standby of the unit from a central location (ESP) (Table 7.4-1) outside the main control room in the event of inaccessibility of the main control room (Section 6.4 on main control room habitability). The design bases for establishing the functional requirements to provide hot shutdown capability from the ESP are as follows:

1. As previously stated, inaccessibility of the main control room shall not occur simultaneously with or subsequent to an accident condition other than a LOOP.

2. The main control board, although not necessarily remaining operable, shall not be affected because of main control room inaccessibility to the extent that the control board generates spurious or unwanted control signals which would prevent hot standby from the ESP.

3. A sufficient quantity of auxiliary feedwater shall be available for decay heat removal until such time as the RHR system can be placed in operation. The AFWS is described in Section 10.4.9.

In the event that a main control room evacuation is required, the controls and monitoring instrumentation, which are located on the ESP, will be utilized.

The design criteria for control room evacuation includes single failure and coincident loss of offsite power. Power sources for all Class 1E control circuitry of pumps and valves are the same power sources as those used in the main control room.

Separation of redundant train-related and non-Class 1E circuits is maintained by barriers or appropriate air space. All control equipment (other than indicators) which is part of a Class 1E circuit meet the requirements of IEEE Standard 344-1975, "Seismic Qualification of Class 1E Equipment," and IEEE Standard 323-1974, "Qualifying Class 1E Equipment." Transfer of control to the shutdown panel is accomplished by the transfer pushbuttons and switches on the shutdown panel. Transfer separates all control from the control room. Reset (override) is accomplished by hand reset transfer relays at the local relay panel.

In the event of an exposure fire in the instrumentation and relay room, cable spreading room, west communication room (ESP), or the cable tunnel, the alternate shutdown panel (ASP) is designed to provide instrumentation and controls to support safe shutdown.

The switching capability of the ASP (Table 7.4-2) provides a means of shutdown capability support that bypasses all equipment and electrical cables located in the previously mentioned four fire areas. All electrical cables that pass through these areas and which are required for safe shutdown, are electrically removed from their circuits to ensure isolation of the affected fire area and allow independence of the ASP. The ASP will control one train of one redundant division of the Class 1E systems supporting safe shutdown of BVPS-2.

7.4.1.4 Equipment and Systems Available for Cold Shutdown

1. Auxiliary feedwater system pumps (Section 10.4.9),

2. Boric acid transfer pumps and tanks (Section 9.3.4),

3. Charging pumps (Section 9.3.4),

4. Service water system pumps (Section 9.2.1),

5. Main control room ventilation (Section 9.4.1),

6. Component cooling water pumps (Section 9.2.2.1),

7. Residual heat removal system pumps (Section 5.4.7),

8. Certain motor control centers and switchgear sections associated with motors, valves, and heaters on this list (Section 8.1),

9. Controlled steam release and feedwater supply (Sections 7.7 and 10.4.9),

10. Accumulator piping and valving for isolation and venting (Section 6.3),

11. Nuclear instrumentation system (source range or intermediate range) (Section 7.2),

12. Reactor coolant inventory control (charging and letdown) (Section 9.3.4),

13. Pressurizer pressure control, including opening control for pressurizer relief valves and heater control (Sections 10.4 and 7.6),

14. Safety injection trip block control, and

15. Accumulator isolation valve control.

Detailed procedures to be followed in effecting cold shutdown from outside the main control room are best determined by plant personnel at the time of the postulated incident. During such time, the plant could be safely maintained at hot standby.

7.4.2 Analysis

Hot standby is a stable plant condition, automatically reached following a reactor trip from power. Additionally, the plant design features permit the achievement of cold shutdown as referred to herein, such as in Sections 5.4.7 and 7.4.1.4. In the unlikely event that access to the main control room is restricted, the plant can be safely kept at hot standby through the use of monitoring indicators and controls listed in Sections 7.4.1.1 and 7.4.1.2 until the main control room can be re-entered. Cold shutdown conditions can be achieved through the use of suitable procedures and by virtue of control of the equipment listed in Section 7.4.1.4 from the ESP.

The controls available at the ESP provide the capabilities of achieving and maintaining a safe shutdown when the main control room is inaccessible. The controls necessary for immediate operator action to establish a stable plant condition are available at the ESP or in adjacent emergency switchgear rooms. The controls, along with limited operator action, provide a means of sustaining the capability for boration, letdown, RHR, natural circulation, continuing reactor coolant pump essential water services, and secondary system depressurization.

The preceding instrumentation and control functions, which are required to be aligned for maintaining safe shutdown of the reactor, are the minimum number of instrumentation and control functions needed. Some of the equipment that provides part of these instrumentation and control functions are control systems discussed in Section 7.7 that are not part of the protection system. Proper operation of other nonsafety-related control systems will allow a more normal shutdown to be made and maintained by preventing a transient. In considering the more restrictive conditions that Section 7.4 deals with, it can be said that certain accidents and transients are postulated in the Chapter 15 safety analyses which take credit for safe shutdown, when the protection systems' reactor trip terminates the transients and the ESF systems mitigate the consequences of the accident. In these transients, in general, no credit is taken for the control system operation should such operation mitigate the consequences of a transient. Should such operation not mitigate the consequences of a transient, no penalties are taken in the analyses for incorrect control system actions over and above the incorrect action of the control system whose equipment failure was assumed to have initiated the transient. These Chapter 15 analyses show that safety is not adversely affected when such transients include the following:

1. Uncontrolled boron dilution,

2. Loss of normal feedwater,

3. Loss of external electrical load and/or turbine trip, and

4. Loss of ac power to the station auxiliaries (station blackout).

The results of the analysis which determined the applicability of the nuclear steam supply system safe shutdown systems to the USNRC GDC, IEEE Standard 279-1971, applicable USNRC Regulatory Guides, and other industry standards are presented in Table 7.1-1. The functions considered include both safety-related and nonsafety-related equipment and are:

1. Reactor trip system,

2. Engineered safety features actuation system,

3. Safety-related display instrumentation for post-accident monitoring,

4. Main control board,

5. Emergency shutdown panel,

6. Residual heat removal,

7. Instrument power supply, and

8. Control systems.

For the discussion addressing how these requirements are satisfied, the column in Table 7.1-1, entitled Applicable Criteria Discussed in Section, provides the appropriate reference.

7.4.3 References for Section 7.4

U.S. Nuclear Regulatory Commission (USNRC) 1981. Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants. NUREG-0800.

Tables for Section 7.4

TABLE 7.4-1

INSTRUMENTS AND CONTROLS OUTSIDE MAIN
CONTROL ROOM FOR COLD SHUTDOWN

Instruments on ESP	Mark No.
Steam generator level indicators (1 each)	2FWS-LI477A, 487A, 497A
Steam generator pressure indicators (1 each)	2MSS-PI474A, 485A, 496A
Pressurizer level indicators (2)	2RCS-LI459C, 460C
Pressurizer pressure indicators (2)	2RCS-PI444A, 455A
Loop hot leg temperature indicators (1 each)	2RCS-TI413A, 423A, 433A
Loop cold leg temperature indicators (1 each)	2RCS-TI410A, 420A, 430A
Reactor coolant pressure indicators (2)	2RCS-PI441B, 440A
Auxiliary feedwater flow indicators (2/Steam Generator)	2FWE-FI100A3, 100A1, 100B3, 100B1, 100C3, 100C1
RHR return to loop temperature indicators (2)	2RHS-TI606A, 606B
RHR flow indicators (2)	2RHS-FI605A1, 605B1
RHR (Heat Exchanger Outlet) flow indicators (2)	2RHS-FI606A1, 606B1
Volume control tank level indicators (2)	2CHS-LI112A, LI115A
Charging flow indicator	2CHS-FI122A1
Regenerative heat exchanger to loop temperature indicator	2CHS-TI123A
Emergency bus voltmeters (2)	VM-BUS2AE, 2DF
Source range NI (4)	2NMS-NI31BA, 31DA, 32BA, 32DA
Intermediate range NI (4)	2NMI-NI35BA, 35DA, 36BA, 36DA

TABLE 7.4-1 (Cont)

Equipment with Control Switches and Control Transfer Switches on ESP	Mark No.
Auxiliary feedwater control valves	2FWE*HCV100A, 100B, 100C, 100D, 100E, 100F
Emergency boration valve	2CHS*SOV206
Non-regenerative heat exchange discharge valve	2CHS*PCV145
Letdown to coolant recovery tanks	2CHS*MOV100A, 100B
Turbine driven auxiliary feed pump steam supply valves	2MSS*SOV105A, 105B, 105C, 105D, 105E, 105F
Atmospheric steam dump valves	2SVS*PCV101A, 101B, 101C
Pressurizer auxiliary spray isolation valve	2CHS*MOV311
Non-regenerative heat exchanger letdown isolation valve	2CHS*AOV204
Letdown orifice isolation valves	2CHS*AOV200A, 200B, 200C
Letdown isolation valves	2CHS*LCV460A, 460B
Charging line to RCS isolation valve	2CHS*MOV310
Boric acid tank to charging pump suction	2CHS*MOV350
Reactor coolant system spray valve	2CHS*MOV311
Charging pump suction from RWST	2CHS*LCV115B, 115D
Volume control tank isolation valves	2CHS*LCV115C, 115E
Residual heat exchanger PCCW outlet valve and pump seal cooler	2CCP*MOV112A, 112B
Residual heat removal inlet isolation valves	2RHS*701A, 701B, 702A, 702B
Residual heat removal safety injection return isolation valves	2RHS*MOV720A, 720B

TABLE 7.4-1 (Cont)

Equipment with Control Switches and Control Transfer Switches on ESP	Mark No.
Atmospheric residual heat release valve	2SVS*HCV104
Safety injection accumulator isolation valve	2SIS*MOV865A, 865B, 865C
Charging pump discharge flow	2CHS*FCV122
Residual heat removal purification valve	2CHS*HCV142
Residual heat removal bypass valve	2RHS*FCV605A, 605B
Residual heat exchanger outlet valves	2RHS*HCV758A, 758B
Residual heat removal cross-connection valves	2RHS*MOV750A, 750B
Primary plant component cooling water pumps	2CCP*P21A, 21B, 21C
Charging pumps	2CHS*P21A, 21B, 21C
Boric acid transfer pumps	2CHS*P22A, 22B
Steam generator motor-driven auxiliary feed pumps	2FWE*P23A, 23B
Containment air recirculation fans	2HVR-FN201A, 201B, 201C
Pressurizer heaters	2RCP*H2A, H2B
Residual heat removal pumps	2RHS*P21A, 21B
Service water pumps	2SWS*P21A, 21B, 21C
Miscellaneous Controls	
Bus 2A supply from system station Transformer 2A breaker	BRKR 42A
Bus 2D supply from system station Transformer 2B breaker	BRKR 342B
Bus 2AE normal tie breaker	BRKR 2A10
Bus 2DF supply breaker	BRKR 2D10
Bus 2AE supply breaker	BRKR 2E7

TABLE 7.4-1 (Cont)

Equipment with Control Switches and Control Transfer Switches on ESP	Mark No.
Bus 2DF supply breaker	BRKR 2F7
Diesel generator 2-1 breaker	BRKR 2E10
Diesel generator 2-2 breaker	BRKR 2F10
Emergency diesel generator 2-1 Emergency diesel generator start Emergency diesel generator stop	
Emergency diesel generator 2-2 Emergency diesel generator start Emergency diesel generator stop	
Pressurizer SI block/reset	
Steam line SI block/reset	

TABLE 7.4-2

EQUIPMENT ON ALTERNATE SHUTDOWN PANEL

Equipment	Equipment Mark No.
Residual heat removal pump	2RHS*P21A(AO)
Residual heat removal supply isolation valve	2RHS*MOV701A(AO)
Residual heat removal supply isolation valve	2RHS*MOV702A(AO)
Residual heat removal isolation to CL22	2RHS*MOV720A(AO)
Primary component cooling	2CCP*P21A(AO)
Residual heat removal heat exchanger 21A supply	2CCP*MOV112A(AO)
Service water pump	2SWS*P21A(AO)
Steam generator auxiliary feed pump	2FWE*P23A(AO)
Auxiliary feed pump header to steam generator	2FWE*HCV100C(AO)
Auxiliary feed pump header to steam generator	2FWE*HCV100E(AO)
Pressurizer heater	2RCP-H2A(ZO)
Atmosphere steam dump valve to steam generator A	2SVS*PCV101A(AO)
Atmosphere steam dump valve to steam generator B	2SVS*PCV101B(AO)
Charging pump	2CHS*P21A(AO)
Charging pump discharge flow line	2CHS*FCV122(Z-)
Pressurizer power relief	2RCS*PCV456(BO)
Nitrogen supply valve to safety injection	2GNS*SOV853A(AO)
Nitrogen supply valve to safety injection	2GNS*SOV853B(BO)
Nitrogen supply valve to safety injection	2GNS*SOV853C(CO)
Safety injection accumulator nitrogen vents	2GNS*SOV854A(AO)
Letdown isolation valve supply	2CHS*LCV460A(ZO)
Letdown isolation valve	2CHS*LCV460B(ZO)
Letdown valve - coolant recovery	2CHS*MOV100A(-O)
Letdown valve - coolant recovery	2CHS*MOV100B(-O)
Letdown orifice isolation valve	2CHS*AOV200A(AO)
Nonregenerative heat exchanger discharge	2CHS*PCV145
Boric acid transfer pump	2CHS*P22A(AO)
Redundant to emergency boration	2CHS*SOV206(ZO)
Emergency diesel generator set	2EGS*EG2-1(-O)
Steam generator level (Loop 21)	2FWS-LI477F
Steam generator level (Loop 22)	2FWS-LI487F
Steam generator discharge pressure (Loop 21)	2MSS-PI475F
Steam generator discharge pressure (Loop 22)	2MSS-PI485F
Presurizer level protection (Loop 21)	2RCS-LI459AF
Reactor coolant pressure (Loop 21)	2RCS-PI403F
Pressurizer pressure protection (Loop 21)	2RCS-PI455F
Reactor coolant hot leg temperature (Loop 21)	2RCS-TI413F
Reactor coolant hot leg temperature (Loop 22)	2RCS-TI423F
Reactor coolant cold leg temperature (Loop 21)	2RCS-TI410F
Reactor coolant cold leg temperature (Loop 22)	2RCS-TI420F
Steam generator auxiliary feed line	2FWE-FI100AF
Steam generator auxiliary feed line	2FWE-FI100BF

TABLE 7.4-2 (Cont)

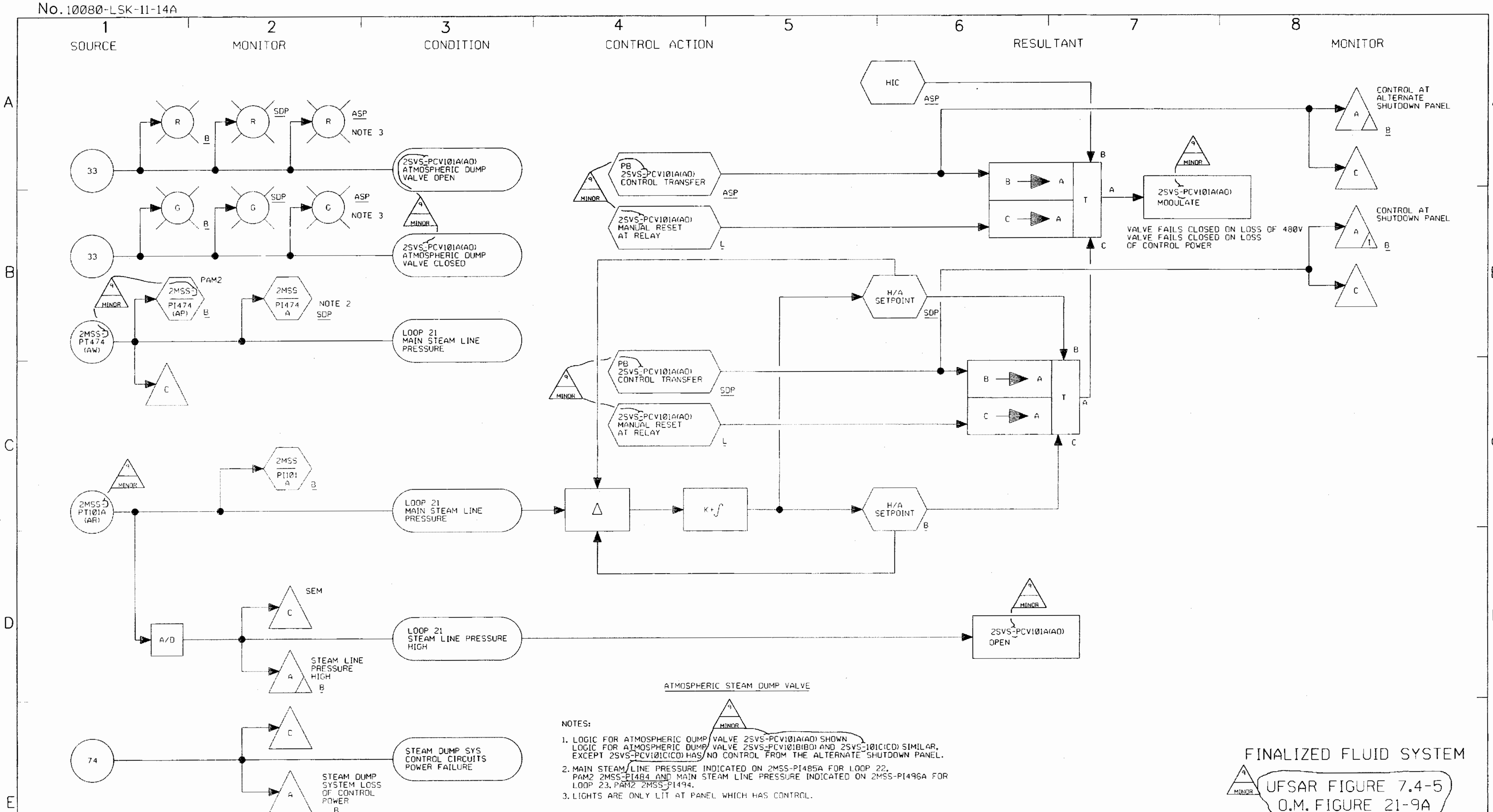
Equipment	Equipment Mark No.
Source range count rate	2NMS-NI31BF
Source range start-up rate	2NMS-NI31DF
Bus 2A supply breaker	ACB-42A
Bus 2AE supply breaker	ACB-2A10
Bus 2AE emergency supply breaker	ACB*2E7
Emergency diesel generator supply breaker	ACB*2E10
Diesel generator heat exchanger service water header valve	2SWS*MOV113A(AO)
Service water pump discharge valve	2SWS*MOV102A(AO)
Charging pump suction valve from refueling water storage tank	2CHS*LCV115B(AO)

TABLE 7.4-3

REMOTE SHUTDOWN PANEL MONITORING INSTRUMENTATION

	INSTRUMENT	MEASUREMENT RANGE
1.	Intermediate Range Nuclear Flux	10^{-11} to 10^{-3} amps
2.	Intermediate Range Startup Rate	-1.5 to +5.0 DPM
3.	Source Range Nuclear Flux	10^{0} to 10^{6} CPS
4.	Source Range Startup Rate	-1.5 to +5 DPM
5.	Reactor Coolant Temperature - Hot Leg	0 - 700°F
6.	Reactor Coolant Temperature - Cold Leg	0 - 700°F
7.	Pressurizer Pressure	1700 to 2500 psig
8.	Pressurizer Level	0 - 100%
9.	Steam Generator Pressure	0 - 1200 psig
10.	Steam Generator Water Level	0 - 100%
11.	RHR Temperature - HX Outlet	50 - 400°F
12.	Auxiliary Feedwater Flow	0 - 400 GPM

No. 10080-LSK-11-14A



ATMOSPHERIC STEAM DUMP VALVE

NOTES:

1. LOGIC FOR ATMOSPHERIC DUMP VALVE 2SVS-PCV101A(AO) SHOWN LOGIC FOR ATMOSPHERIC DUMP VALVE 2SVS-PCV101B(BO) AND 2SVS-101C(CO) SIMILAR, EXCEPT 2SVS-PCV101C(CO) HAS NO CONTROL FROM THE ALTERNATE SHUTDOWN PANEL.
2. MAIN STEAM LINE PRESSURE INDICATED ON 2MSS-PI485A FOR LOOP 22, PAM2 2MSS-PI484 AND MAIN STEAM LINE PRESSURE INDICATED ON 2MSS-PI496A FOR LOOP 23, PAM2 2MSS-PI494.
3. LIGHTS ARE ONLY LIT AT PANEL WHICH HAS CONTROL.

FINALIZED FLUID SYSTEM

9 MINOR

UFSAR FIGURE 7.4-5
O.M. FIGURE 21-9A

ISSUES	
9 MINOR DWG. CHANGE CR 01-2733 ADDED UFSAR FIG. NO.	MINOR DWG. CHANGES REPLACED (*) WITH (-) IN ASSET NO.'S & ADDED O.M. FIG. NO.

FENOC FIRSTENERGY NUCLEAR OPERATING COMPANY

BEAVER VALLEY POWER STATION UNIT 2

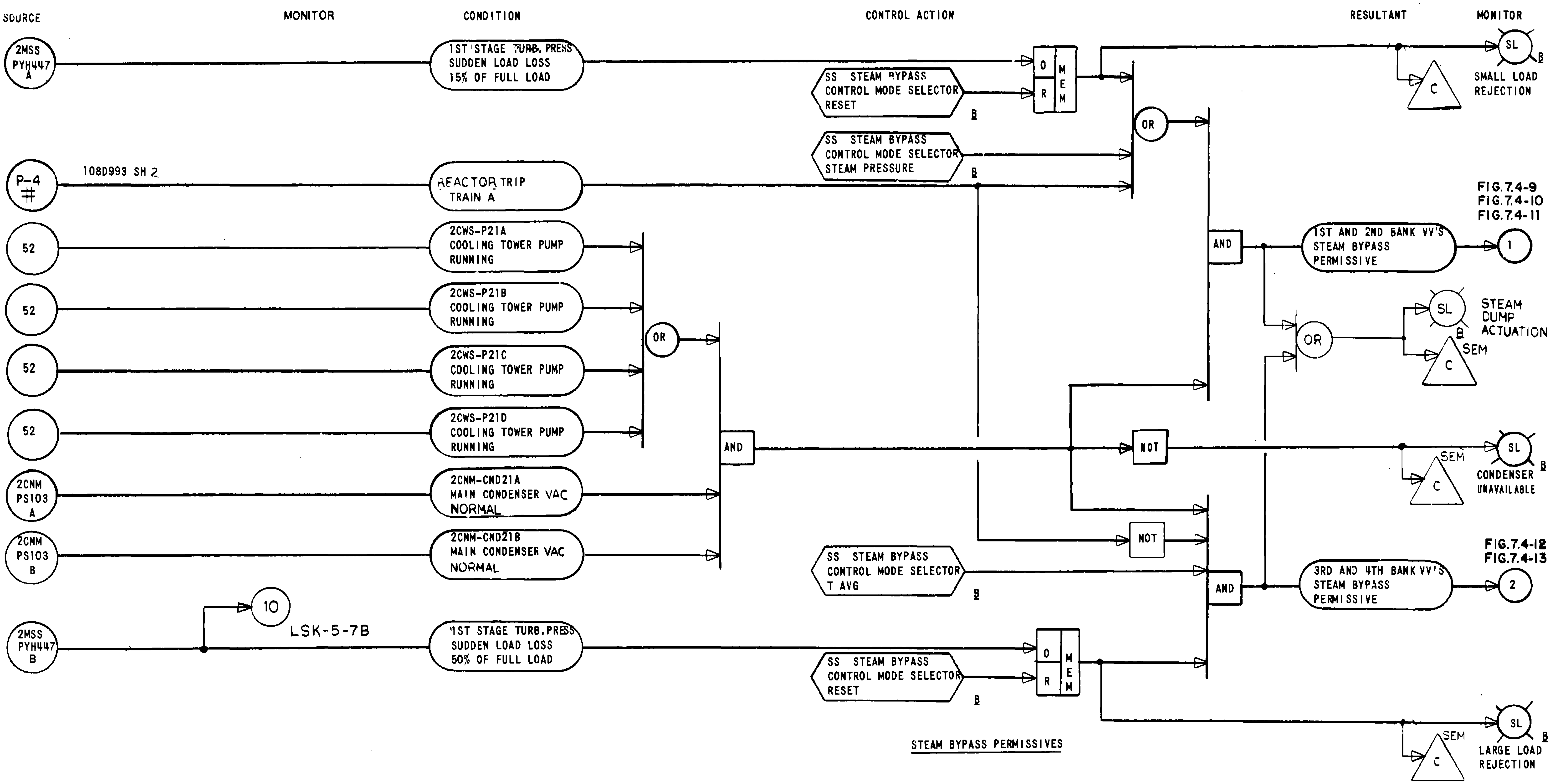
LOGIC DIAGRAM
STEAM BYPASS SYSTEM

SCALE NTS	DATE 10-29-01	ARCH. APP	FINAL APP. FOR ISSUE MGR/SUP:
	DRAWN BY R.W.ROTH	ELECT APP. N/A	
	DFG./CHK	MECH APP	
	ENGR./CHK N/A	CIVIL APP	

O.F.E. NO. | STA NO 100014 | A | DWG. NO. 10080-LSK-11-14A | REV 9

PREPARED ON THE BVPS CAEDD SYSTEM

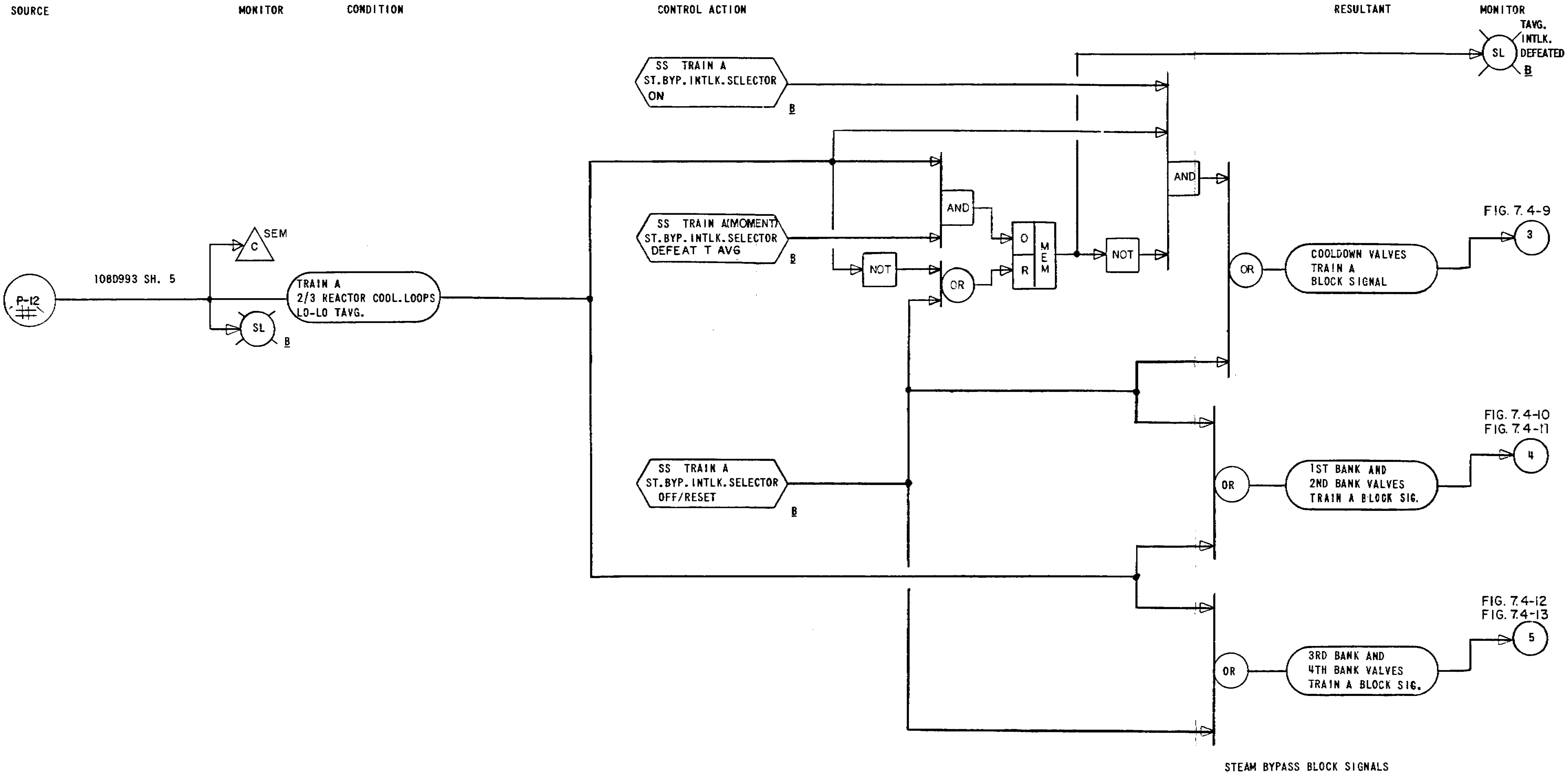
REV 12



NOTES: 1. STEAM BYPASS CONTROL MODE SELECTOR SWITCH IS MAINTAINED IN "STEAM PRESSURE", SPRING RETURN TO "T AVG" FROM "RESET".

2. # BY WESTINGHOUSE.

FIGURE 7.4-6
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES: 1.

1ST BANK VALVES	2ND BANK VALVES	3RD BANK VALVES	4TH BANK VALVES
2MSS-PCV106A	2MSS-TCV106D	2MSS-TCV106A	2MSS-TCV106C
2MSS-TCV106H	2MSS-TCV106E	2MSS-TCV106B	2MSS-TCV106G
2MSS-PCV106B	2MSS-TCV106M	2MSS-TCV106F	2MSS-TCV106J
2MSS-PCV106C	2MSS-TCV106P	2MSS-TCV106K	2MSS-TCV106N
2MSS-TCV106L		2MSS-TCV106Q	

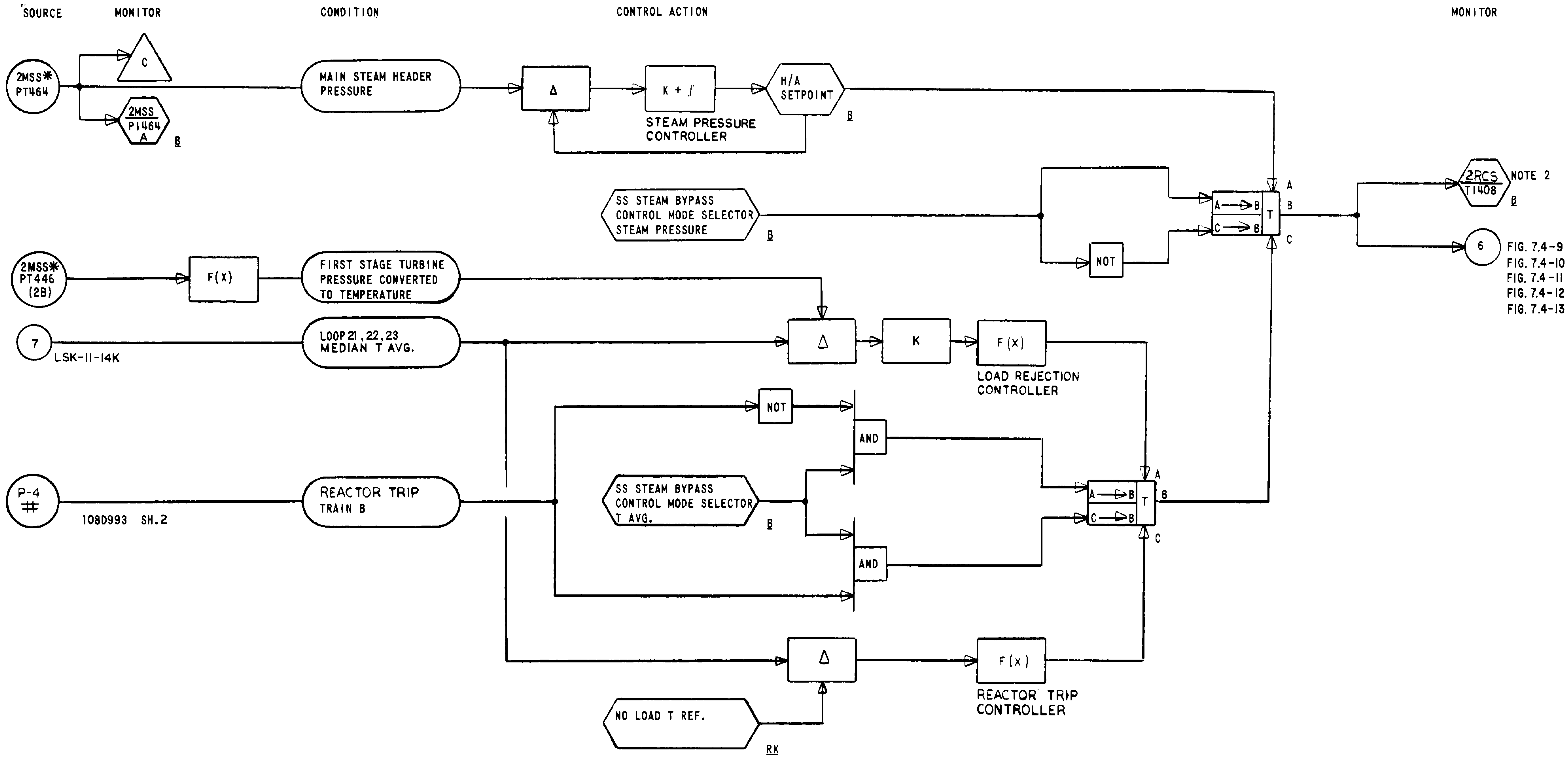
2. STEAM BYPASS INTERLOCK SELECTOR SWTICH IS MAINTAINED IN "OFF/RESET", SPRING RETURN TO "ON" FROM "DEFEAT T AVG."

3. LOGIC FOR TRAIN A BLOCK SIGNALS SHOWN, LOGIC FOR TRAIN B BLOCK SIGNALS SIMILAR.

4 # BY WESTINGHOUSE.

FIGURE 7.4-7
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12



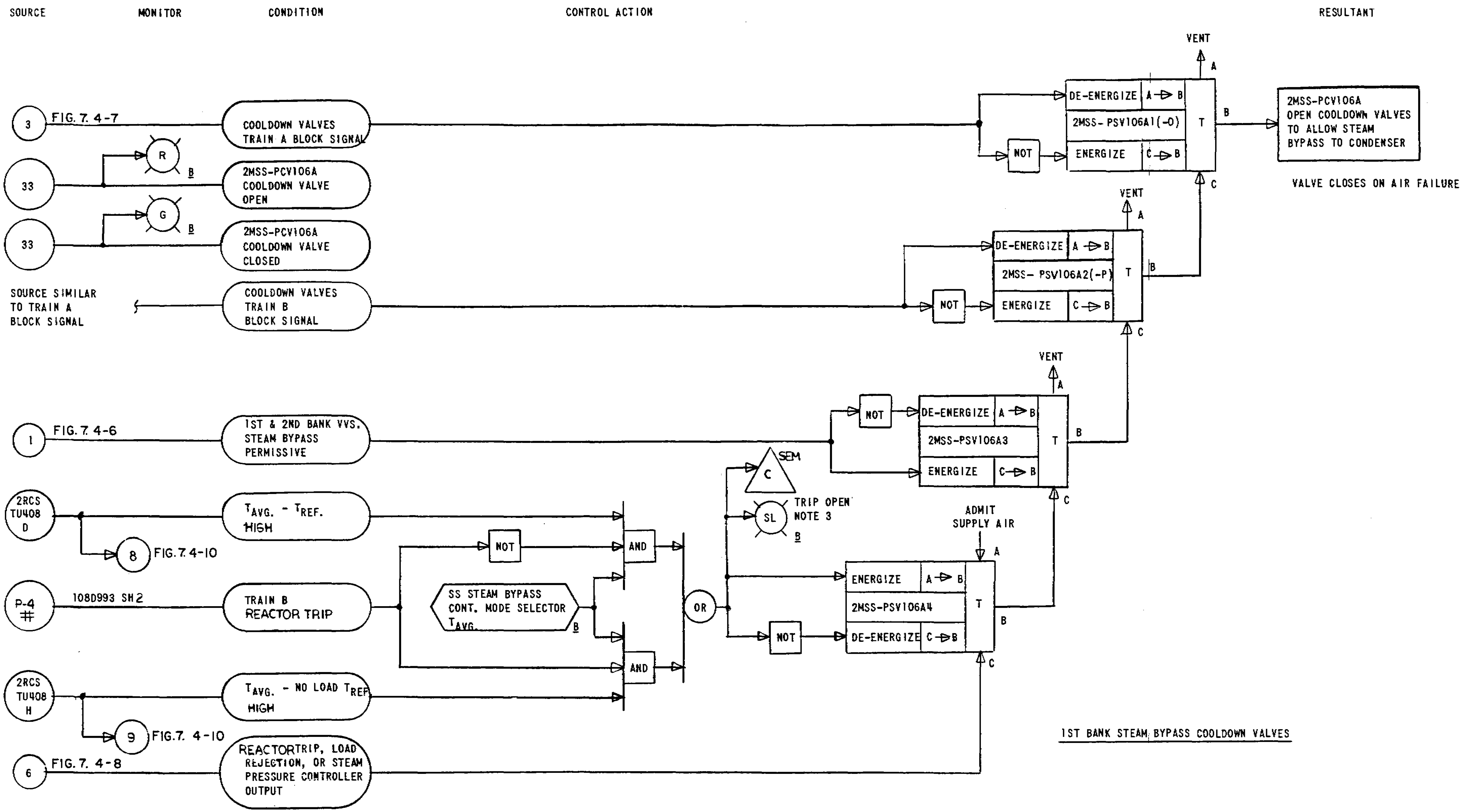
NOTES:

1. STEAM BYPASS CONTROL MODE SELECTOR SWITCH IS MAINTAINED IN "STEAM PRESSURE", SPRING RETURN TO "T AVG." FROM "RESET".

2. ANALOG DISPLAY TO SHOW MAGNITUDE OF CONTROL SIGNAL.

3. BY WESTINGHOUSE

FIGURE 7.4-8
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

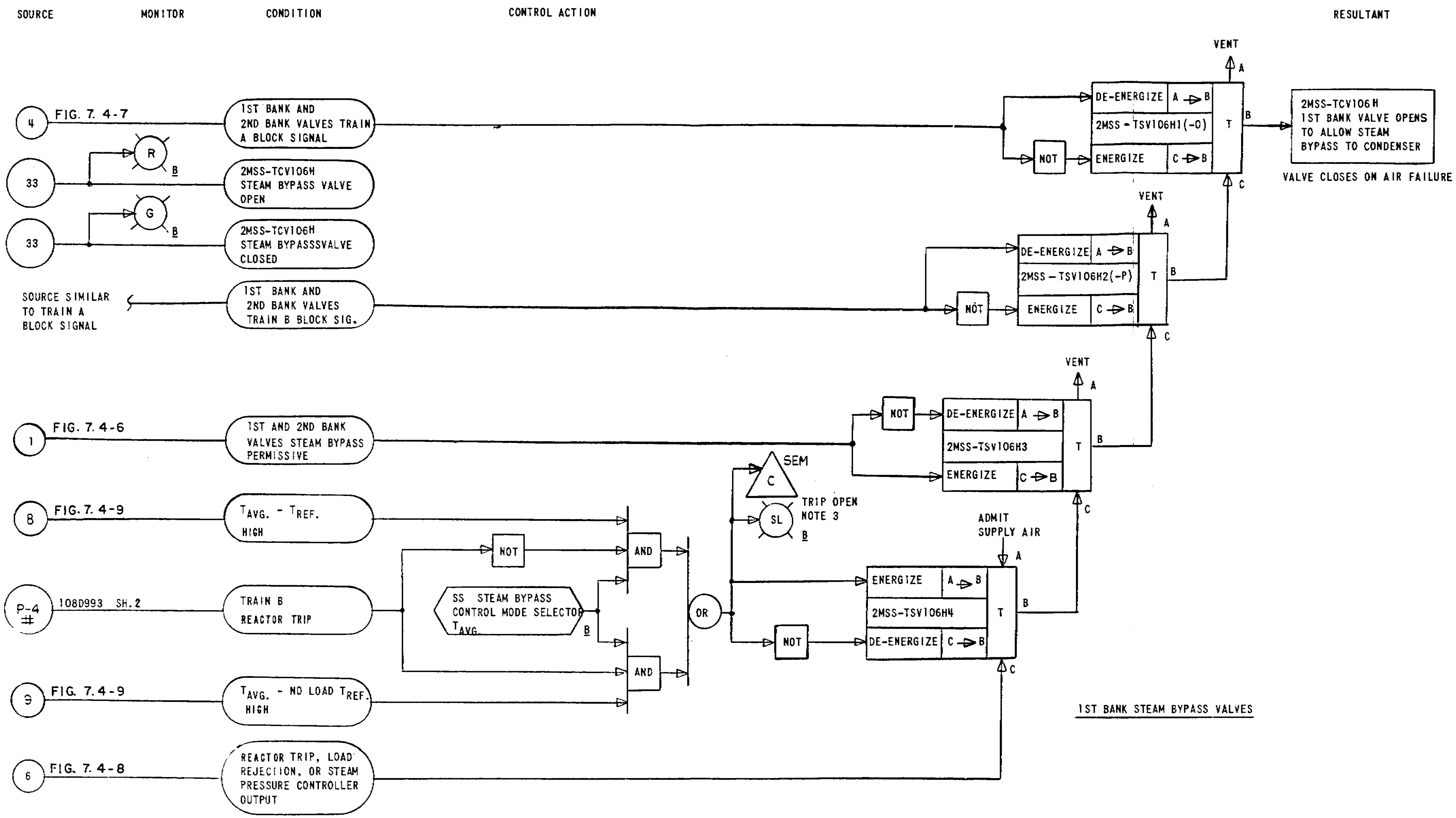


NOTES:
1. LOGIC FOR 2MSS-PCV106A SHOWN, LOGIC FOR 2MSS-PCV106B AND C SIMILAR
2. ASSOCIATED MARK NUMBERS:

VALVE	1ST SOV	2ND SOV	3RD SOV	4TH SOV
2MSS-PCV106A	2MSS - PSV106A1(-O)	2MSS - PSV106A2(-P)	2MSS-PSV106A3	2MSS-PSV106A4
2MSS-PCV106B	2MSS - PSV106B1(-O)	2MSS - PSV106B2(-P)	2MSS-PSV106B3	2MSS-PSV106B4
2MSS-PCV106 C	2MSS - PSV106C1(-O)	2MSS - PSV106C2(-P)	2MSS-PSV106C3	2MSS-PSV106C4

3. COMMON FOR ALL STEAM BYPASS VALVES.
4. # BY WESTINGHOUSE

FIGURE 7.4-9
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES: 1. LOGIC FOR 2MSS-TCV106H SHOWN, LOGIC FOR 2MSS-TCV106L SIMILAR.

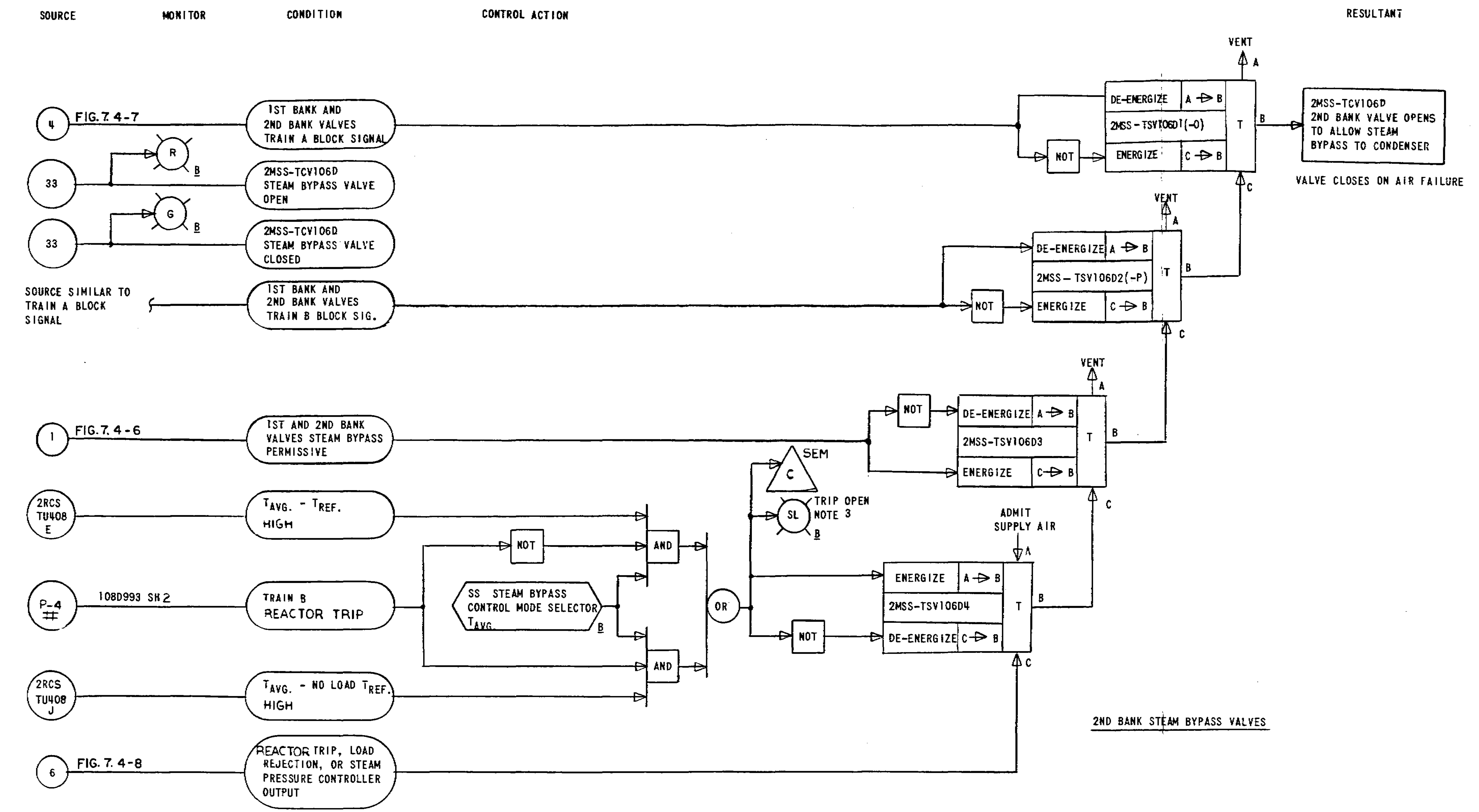
2. ASSOCIATED MARK NUMBERS:

VALVE	1ST SOV	2ND SOV	3RD SOV	4TH SOV
2MSS-TCV106H	2MSS-TSV106H1(-O)	2MSS-TSV106H2(-P)	2MSS-TSV106H3	2MSS-TSV106H4
2MSS-TCV106L	2MSS-TSV106L1(-O)	2MSS-TSV106L2(-P)	2MSS-TSV106L3	2MSS-TSV106L4

3. COMMON FOR ALL STEAM BYPASS VALVES.

4. # BY WESTINGHOUSE

FIGURE 7.4-10
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



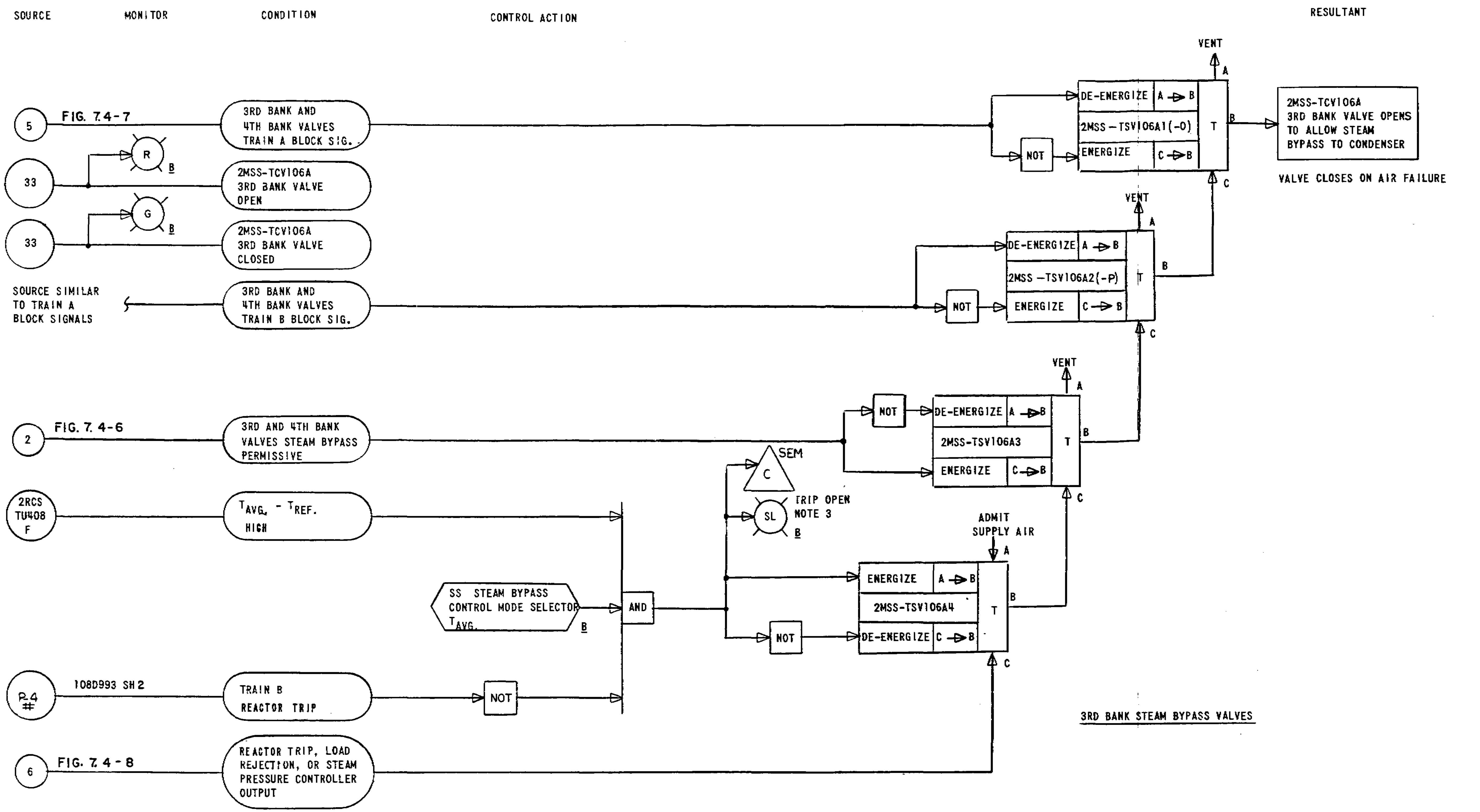
NOTES:

1. LOGIC SHOWN FOR; LOGIC SIMILAR FOR:

VALVE	1ST SOV	2ND SOV	3RD SOV	4TH SOV
2MSS-TCV106D	2MSS-TSV106D1(-O)	2MSS-TSV106D2(-P)	2MSS-TSV106D3	2MSS-TSV106D4
2MSS-TCV106E	2MSS-TSV106E1(-O)	2MSS-TSV106E2(-P)	2MSS-TSV106E3	2MSS-TSV106E4
2MSS-TCV106M	2MSS-TSV106M1(-O)	2MSS-TSV106M2(-P)	2MSS-TSV106M3	2MSS-TSV106M4
2MSS-TCV106P	2MSS-TSV106P1(-O)	2MSS-TSV106P2(-P)	2MSS-TSV106P3	2MSS-TSV106P4

3. COMMON FOR ALL STEAM BYPASS VALVES.
4. # BY WESTINGHOUSE

FIGURE 7.4-11
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

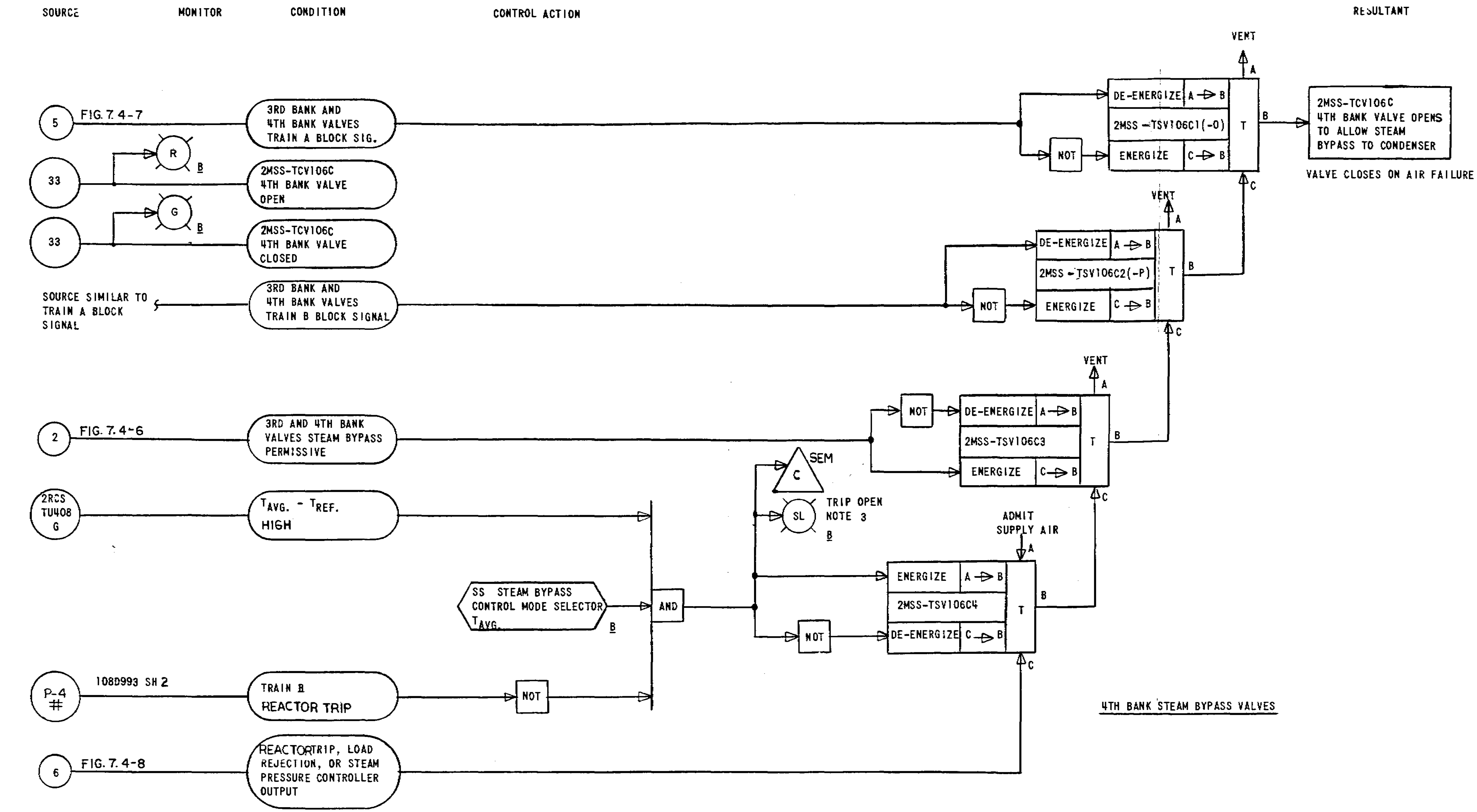


NOTES:

	VALVE	1ST SOV	2ND SOV	3RD SOV	4TH SOV
1. LOGIC SHOWN FOR:	2MSS-TCV106A	2MSS-TSV106A1(-O)	2MSS-TSV106A2(-P)	2MSS-TSV106A3	2MSS-TSV106A4
LOGIC SIMILAR FOR:	2MSS-TCV106B	2MSS-TSV106B1(-O)	2MSS-TSV106B2(-P)	2MSS-TSV106B3	2MSS-TSV106B4
	2MSS-TCV106F	2MSS-TSV106F1(-O)	2MSS-TSV106F2(-P)	2MSS-TSV106F3	2MSS-TSV106F4
	2MSS-TCV106K	2MSS-TSV106K1(-O)	2MSS-TSV106K2(-P)	2MSS-TSV106K3	2MSS-TSV106K4
	2MSS-TCV106Q	2MSS-TSV106Q1(-O)	2MSS-TSV106Q2(-P)	2MSS-TSV106Q3	2MSS-TSV106Q4

3. COMMON TO ALL STEAM BYPASS VALVES.
4. # BY WESTINGHOUSE

FIGURE 7.4-12
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC SHOWN FOR:
   LOGIC SIMILAR FOR:

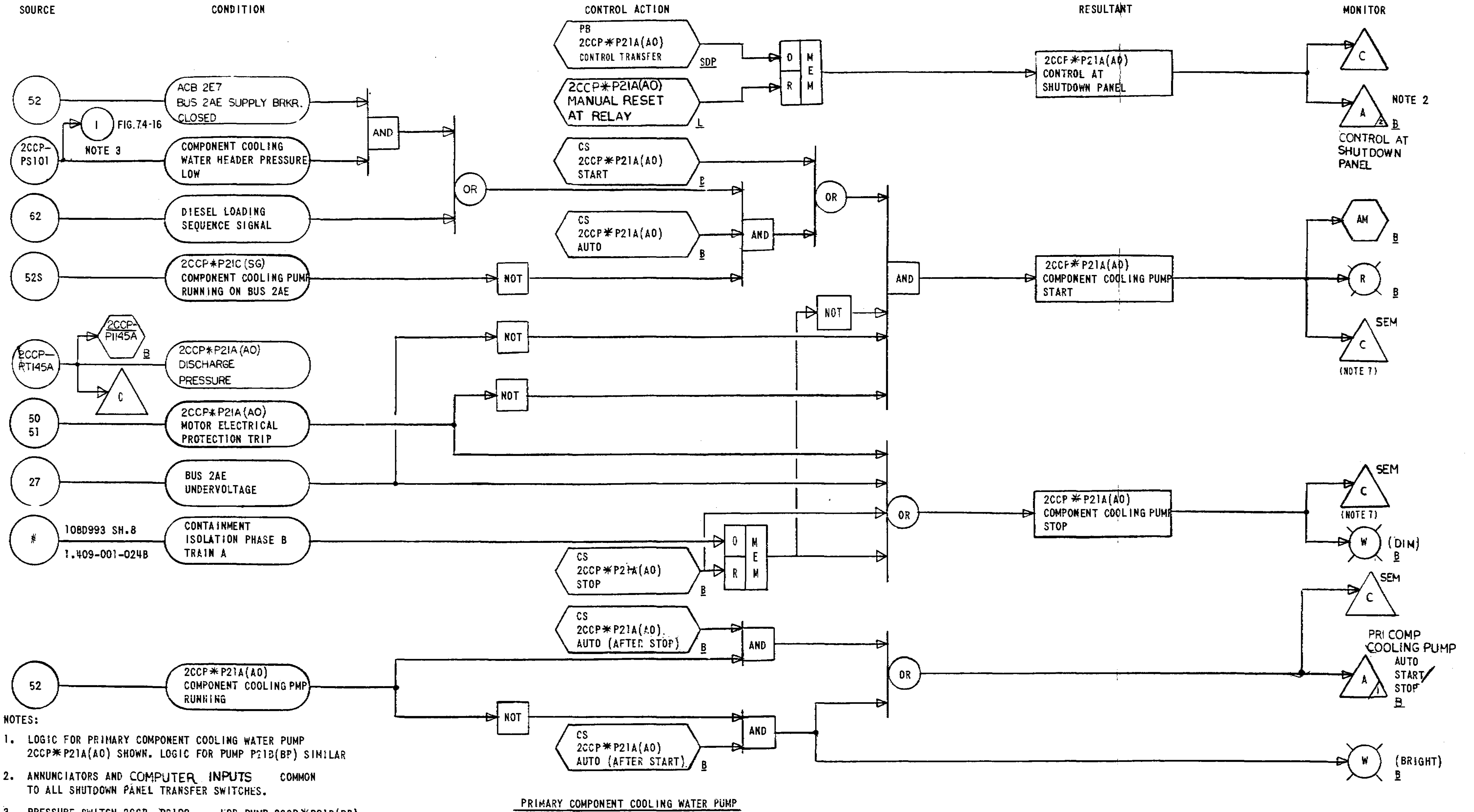
VALVE	1ST SOV	2ND SOV	3RD SOV	4TH SOV
2MSS-TCV106C	2MSS - TSV106C1(-O)	2MSS - TSV106C2(-P)	2MSS-TSV106C3	2MSS-TSV106C4
2MSS-TCV106G	2MSS - TSV106G1(-O)	2MSS - TSV106G2(-P)	2MSS-TSV106G3	2MSS-TSV106G4
2MSS-TCV106J	2MSS - TSV106J1(-O)	2MSS - TSV106J2(-P)	2MSS-TSV106J3	2MSS-TSV106J4
2MSS-TCV106N	2MSS - TSV106N1(-O)	2MSS - TSV106N2(-P)	2MSS-TSV106N3	2MSS-TSV106N4

3. COMMON FOR ALL BYPASS VALVES
4. # BY WESTINGHOUSE

FIGURE 7.4-13
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12

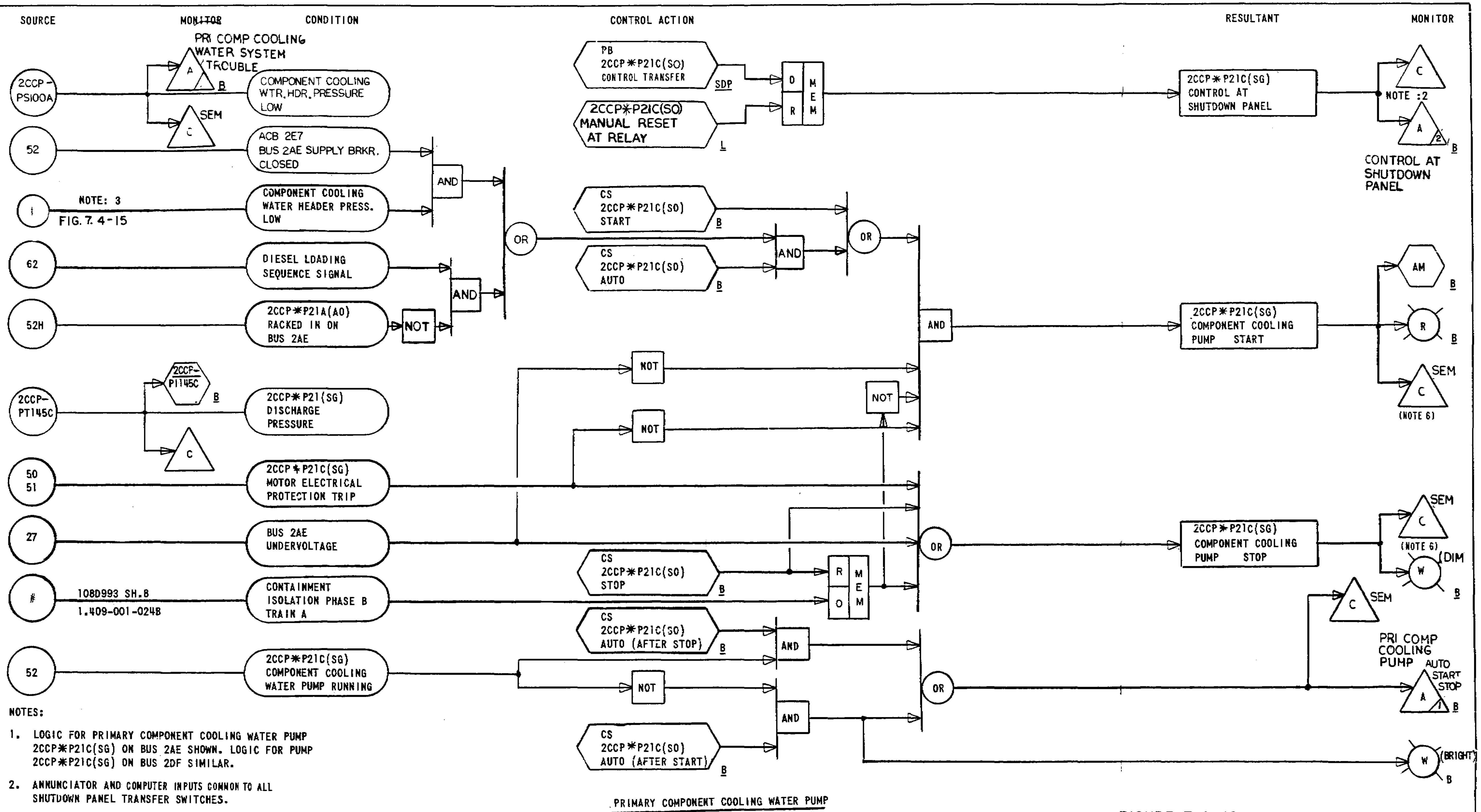
FIGURE 7.4-14
LOGIC DIAGRAM
STEAM BYPASS SYSTEM
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR PRIMARY COMPONENT COOLING WATER PUMP 2CCP✱P21A(AO) SHOWN. LOGIC FOR PUMP P21B(BP) SIMILAR
2. ANNUNCIATORS AND COMPUTER INPUTS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. PRESSURE SWITCH 2CCP- PS102 FOR PUMP 2CCP✱P21B(BP).
4. CONTROL FROM BENCH BOARD SHOWN. CONTROL FROM SHUTDOWN PANEL SIMILAR.
5. CONTROL FROM BENCH BOARD IS ONLY AVAILABLE WHEN CONTROL TRANSFER IS RESET.
6. SEE ADDITIONAL CONTROL OF 2CCP✱P21A(AO) ON FIG. 7.4-17
7. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.

FIGURE 7.4-15
LOGIC DIAGRAM
PRIMARY COMPONENT
COOLING WATER PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

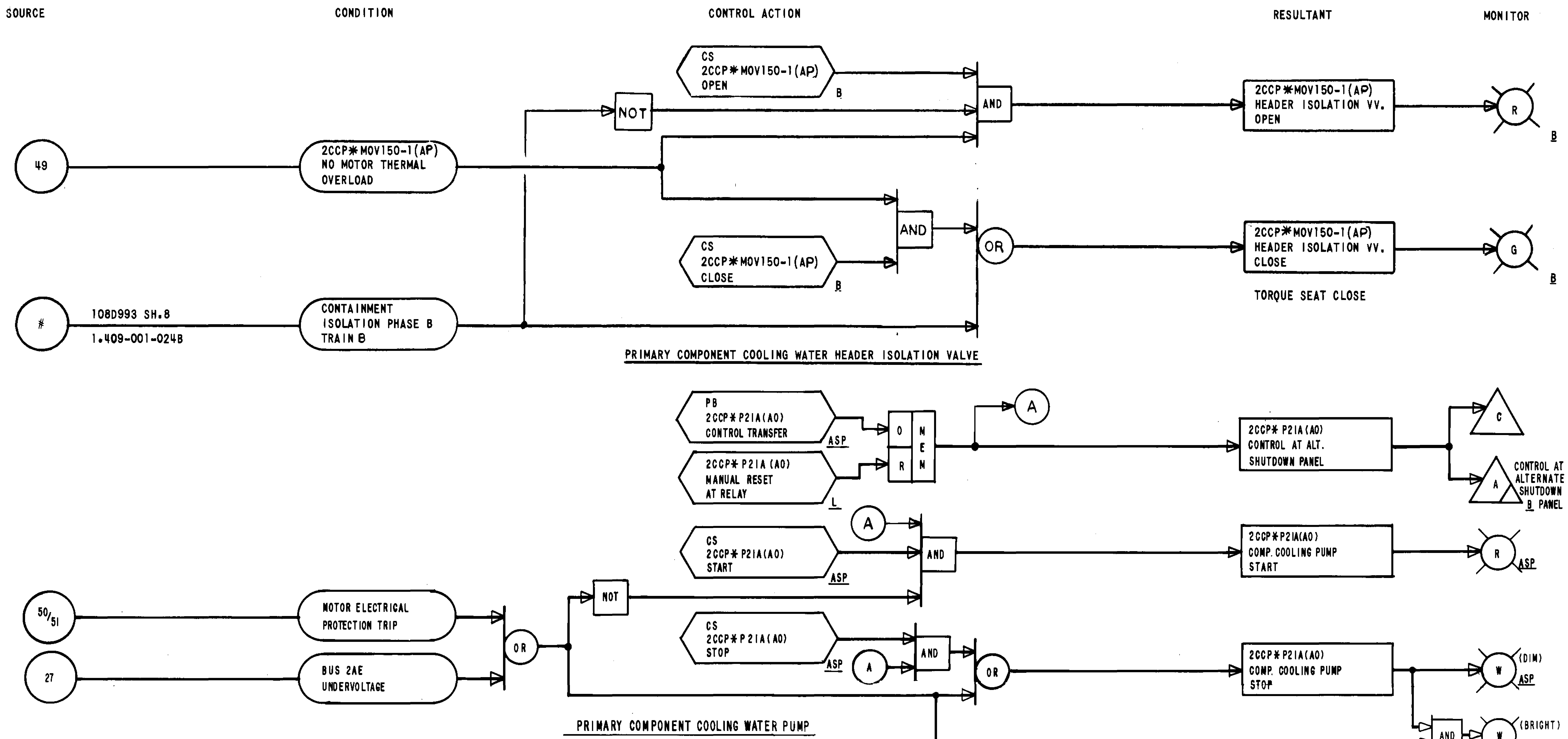


NOTES:

1. LOGIC FOR PRIMARY COMPONENT COOLING WATER PUMP 2CCP*P21C(SG) ON BUS 2AE SHOWN. LOGIC FOR PUMP 2CCP*P21C(SG) ON BUS 2DF SIMILAR.
2. ANNUNCIATOR AND COMPUTER INPUTS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. PRESSURE SWITCH 2CCP-PS102 FOR PUMP 2CCP*P21C(SG) ON BUS 2DF.
4. CONTROL FROM BENCH BOARD SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR.
5. CONTROL IN THE BENCH BOARD IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER IS RESET.
6. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.

FIGURE 7.4-16
LOGIC DIAGRAM
COOLING WATER SYSTEM
PRIMARY COMPONENT
COOLING WATER PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12



NOTES:

1. HEADER ISOLATION VALVE 2CCP✱MOV150-1(AP) SHOWN,
   HEADER ISOLATION VALVES 2CCP✱MOV150-2(AO), MOV151-1(BO), MOV151-2(BP)
   MOV156-1(AP), MOV156-2(AO), MOV157-1(BO), AND MOV157-2(BP) SIMILAR.
2. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
3. SEE ADDITIONAL CONTROL OF 2CCP✱P21A(AO) ON FIG. 7.4-15.

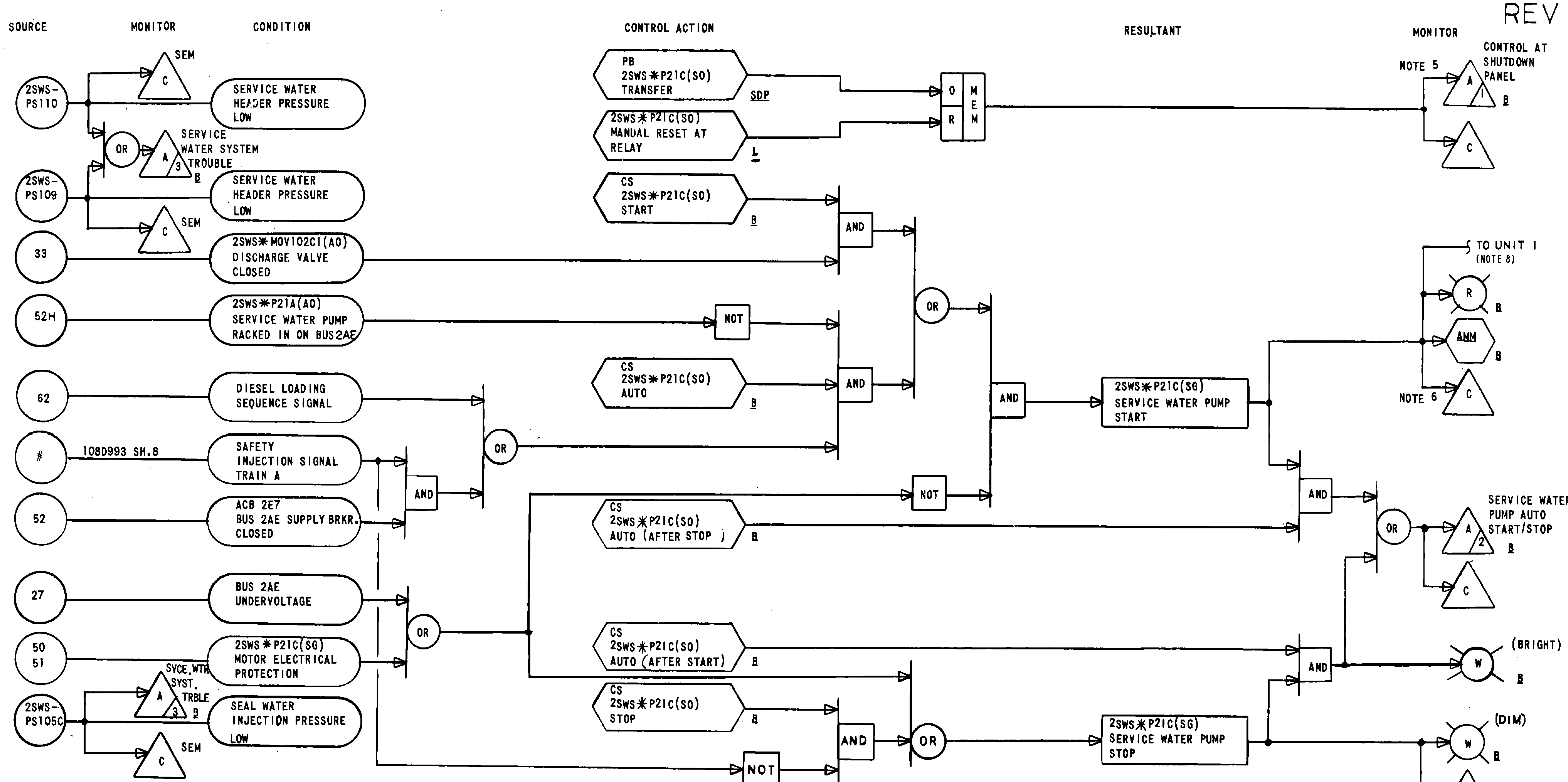
FIGURE 7.4-17
LOGIC DIAGRAM
PRIMARY COMPONENT
COOLING WATER PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12

NOTES:
1. SERVICE WATER PUMP 2SWS•P21A(AO) SHOWN. SERVICE WATER PUMP 2SWS•P21B(BP) SIMILAR.
2. CONTROL FROM MAIN BOARD SHOWN. CONTROL FROM SHUTDOWN PANEL SIMILAR.
3. PUMP CONTROL FROM THE MAIN BOARD IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER SWITCH IS RESET.
4. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
5. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.
6. * BY WESTINGHOUSE
7. SEE ADDITIONAL CONTROL OF 2SWS•P21A(AO) ON FIG. 7.4-26A.
8. UNIT 1 NaOCl INJECTION CONTROL PANEL (PNL-WT-4)

FIGURE 7.4-18
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

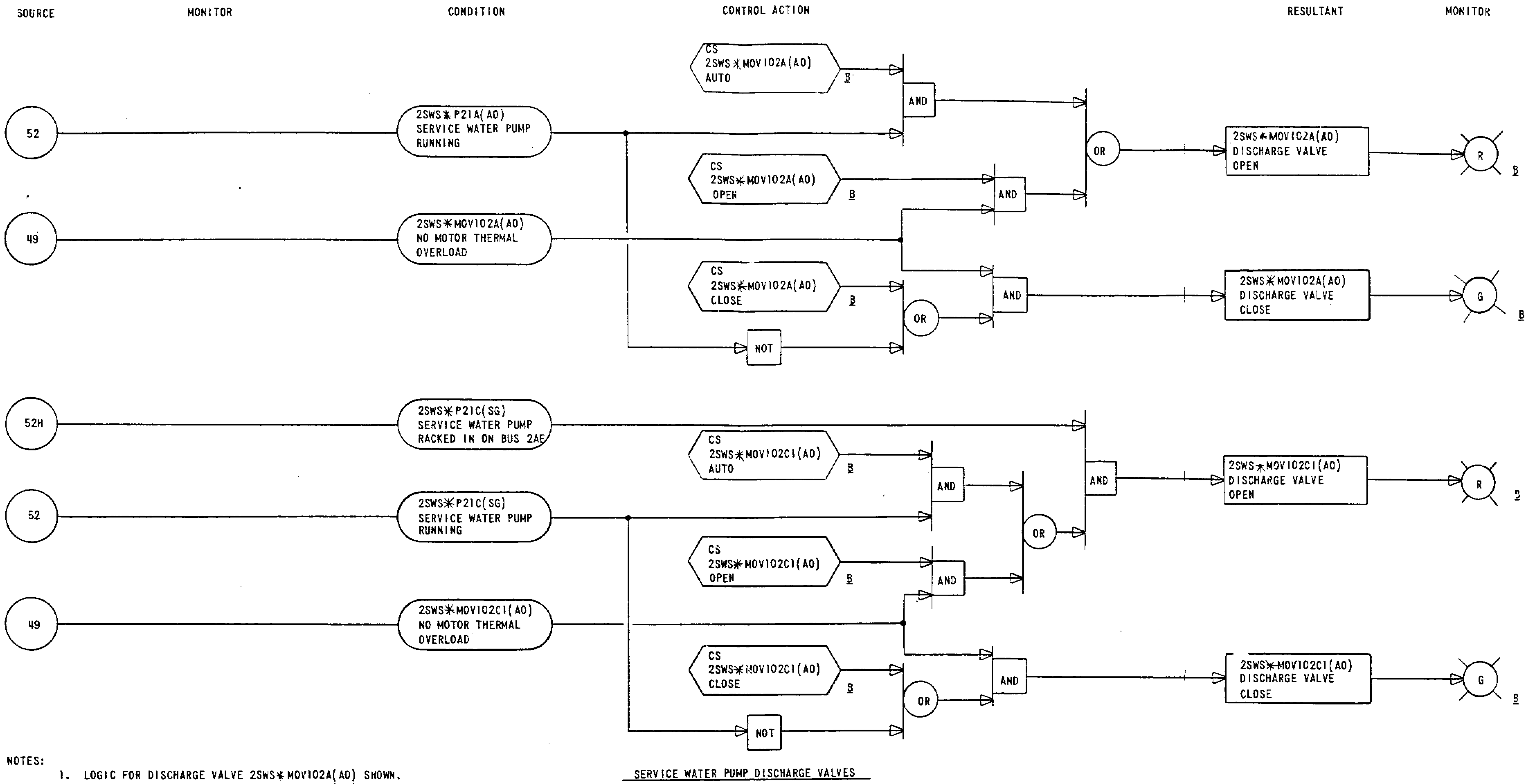
REV 12



NOTES:

1. SERVICE WATER PUMP 2SWS✱P21C(SG) ON BUS 2AE SHOWN, SERVICE WATER PUMP 2SWS✱P21C(SG) ON BUS 2DF SIMILAR.
2. SERVICE WATER PUMP 2SWS✱P21C(SG) PROVIDED WITH TWO CONTROL SWITCHES 2SWS✱P21C(SO) FOR BUS 2AE AND 2SWS✱P21C(SP) FOR BUS 2DF.
3. CONTROL FROM MAIN BOARD SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR.
4. PUMP CONTROL FROM THE MAIN BOARD IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER IS RESET.
5. ANNUNCIATOR DISPLAY IS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
6. ONE COMUPTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATIONS.
7. # BY MANUFACTURER
8. UNIT I NaOCl INJECTION CONTROL PANEL (PNL-WT-4)

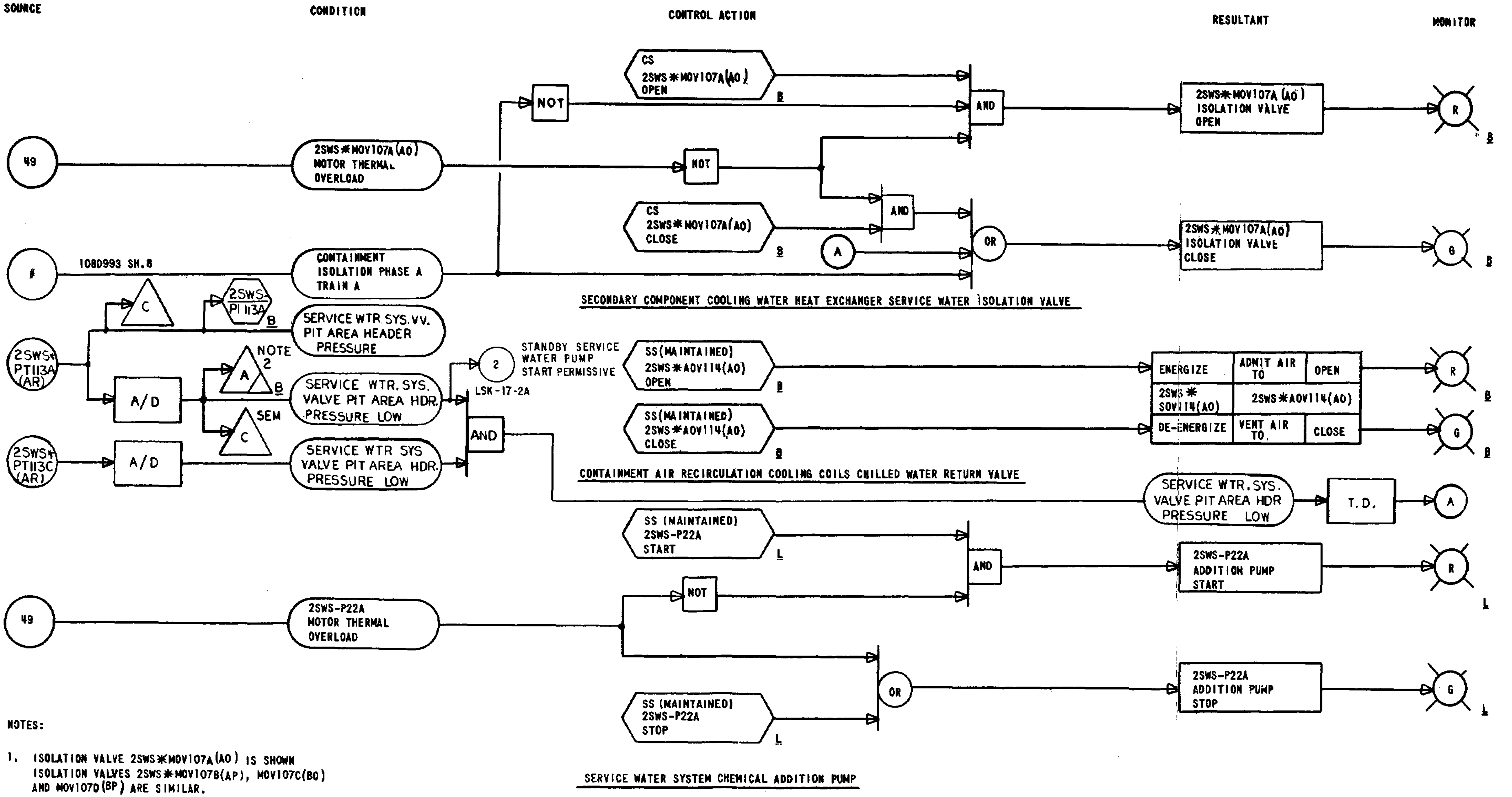
FIGURE 7.4-19
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOGIC FOR DISCHARGE VALVE 2SWS*MOV102A(AO) SHOWN.
   LOGIC FOR DISCHARGE VALVE 2SWS*MOV102B(BP) SIMILAR.
2. LOGIC FOR DISCHARGE VALVE 2SWS*MOV102C1(AO) SHOWN.
   LOGIC FOR DISCHARGE VALVE 2SWS*MOV102C2(BP) SIMILAR.
3. SEE ADDITIONAL CONTROL OF DISCHARGE VALVE 2SWS*MOV102A(AO) ON FIG. 7.4-26C

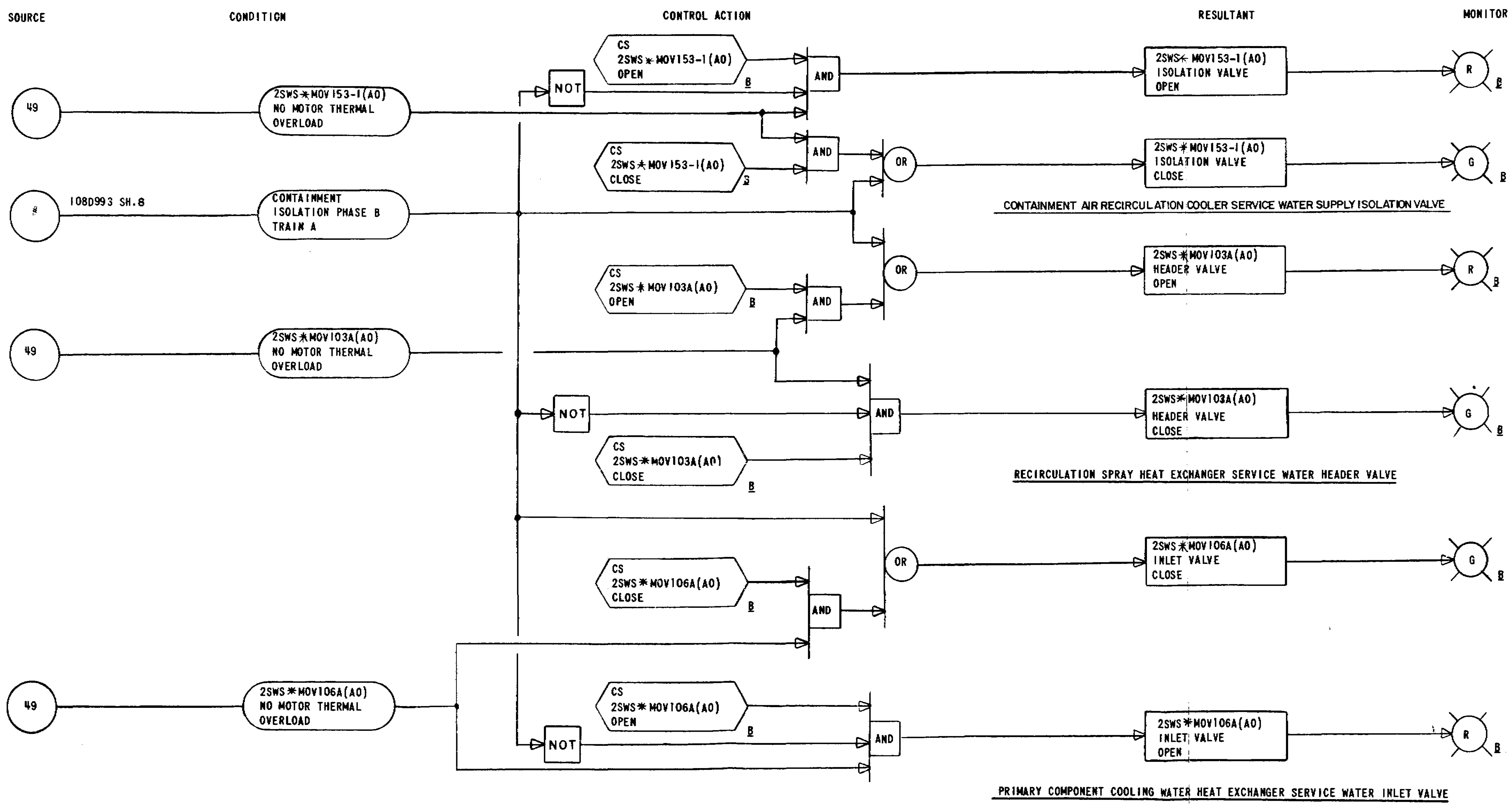
FIGURE 7.4-20
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. ISOLATION VALVE 2SWS*MOV107A(AO) IS SHOWN ISOLATION VALVES 2SWS*MOV107B(AP), MOV107C(BO) AND MOV107D(BP) ARE SIMILAR.
2. SERVICE WATER HEADER PRESSURE LOW.
3. ADDITION PUMP 2SWS-P22A IS SHOWN, ADDITION PUMP 2SWS-P22B IS SIMILAR.
4. # BY MANUFACTURER

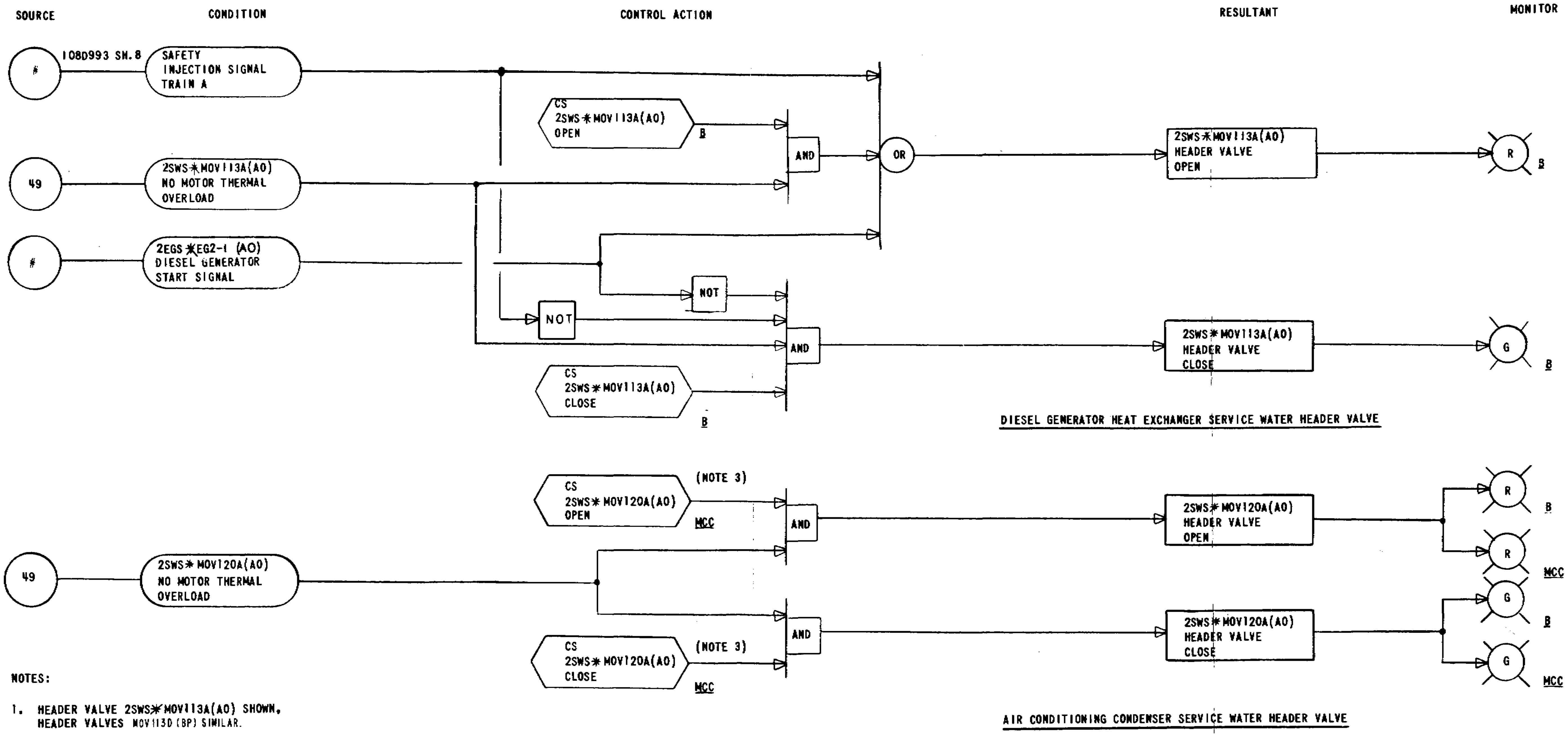
FIGURE 7.4-21
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. HEADER VALVE 2SWS*MOV103A(AO) SHOWN, HEADER VALVE 2SWS*MOV103B(BP) SIMILAR.
2. INLET VALVE 2SWS*MOV106A(AO) SHOWN, INLET VALVE 2SWS*MOV106B(BP) SIMILAR.
3. ISOLATION VALVE 2SWS*MOV153-1(AO) SHOWN, ISOLATION VALVE 2SWS*MOV153-2(AP), MOV152-1(BO), MOV152-2(BP), MOV154-1(AO), MOV154-2(AP), MOV155-1(BO) AND MOV 155-2(BP) SIMILAR.
4. # BY MANUFACTURER

FIGURE 7.4-22
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

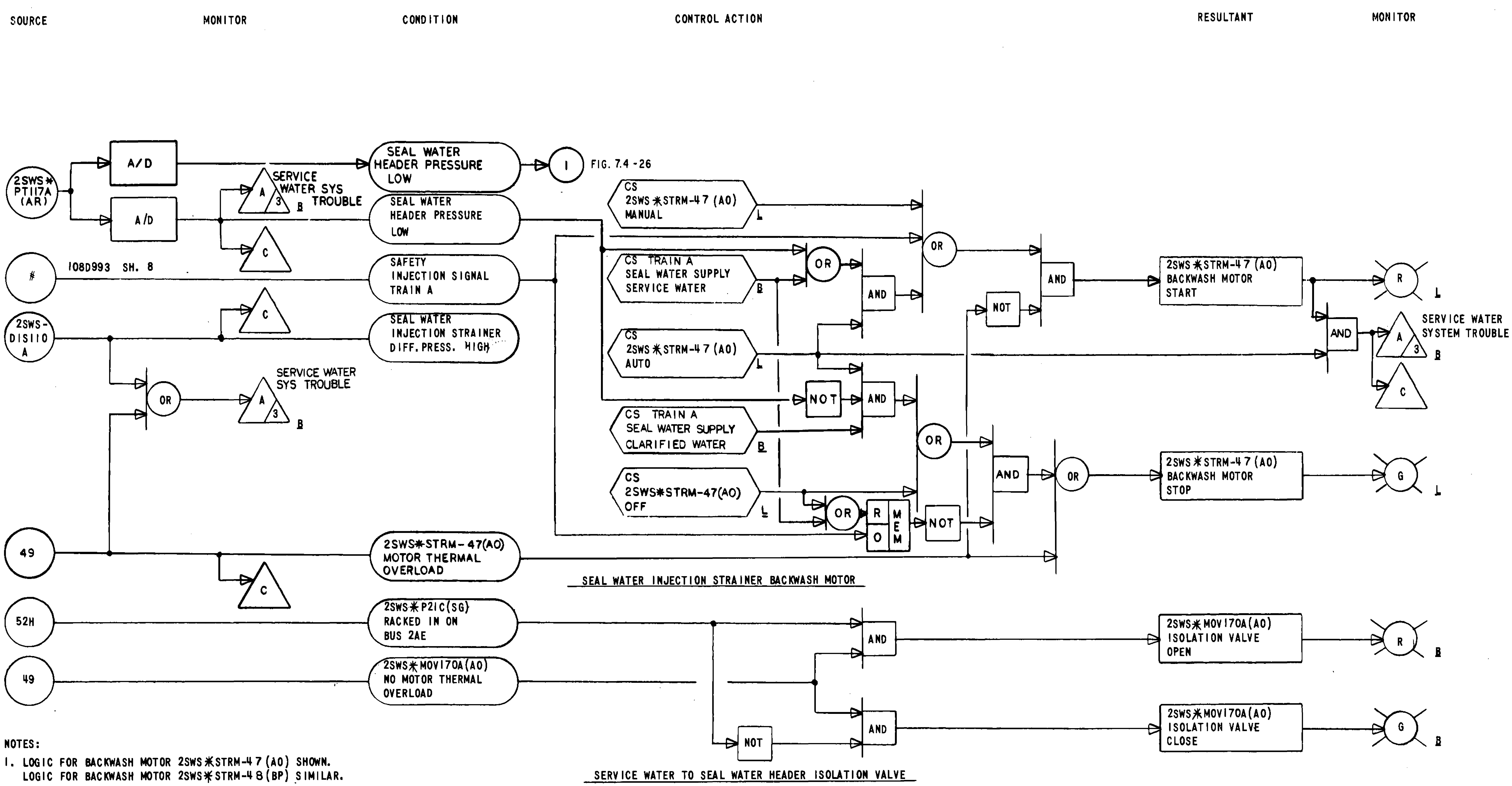


NOTES:

1. HEADER VALVE 2SWS*MOV113A(AO) SHOWN, HEADER VALVES MOV113D(BP) SIMILAR.
2. HEADER VALVE 2SWS*MOV120A(AO) SHOWN, HEADER VALVE 2SWS*MOV120B(BP) SIMILAR.
3. HEADER VALVE 2SWS*MOV120A(AO) AND *MOV120B(BP) ARE LOCKED IN THE OPEN POSITION AT THEIR RESPECTIVE MCC WITH POWER SECURED.
4. # BY MANUFACTURER.
5. SEE ADDITIONAL CONTROL OF HEADER VALVE 2SWS*MOV113A(AO) ON FIGURE 7.4-26C.

FIGURE 7.4-23
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

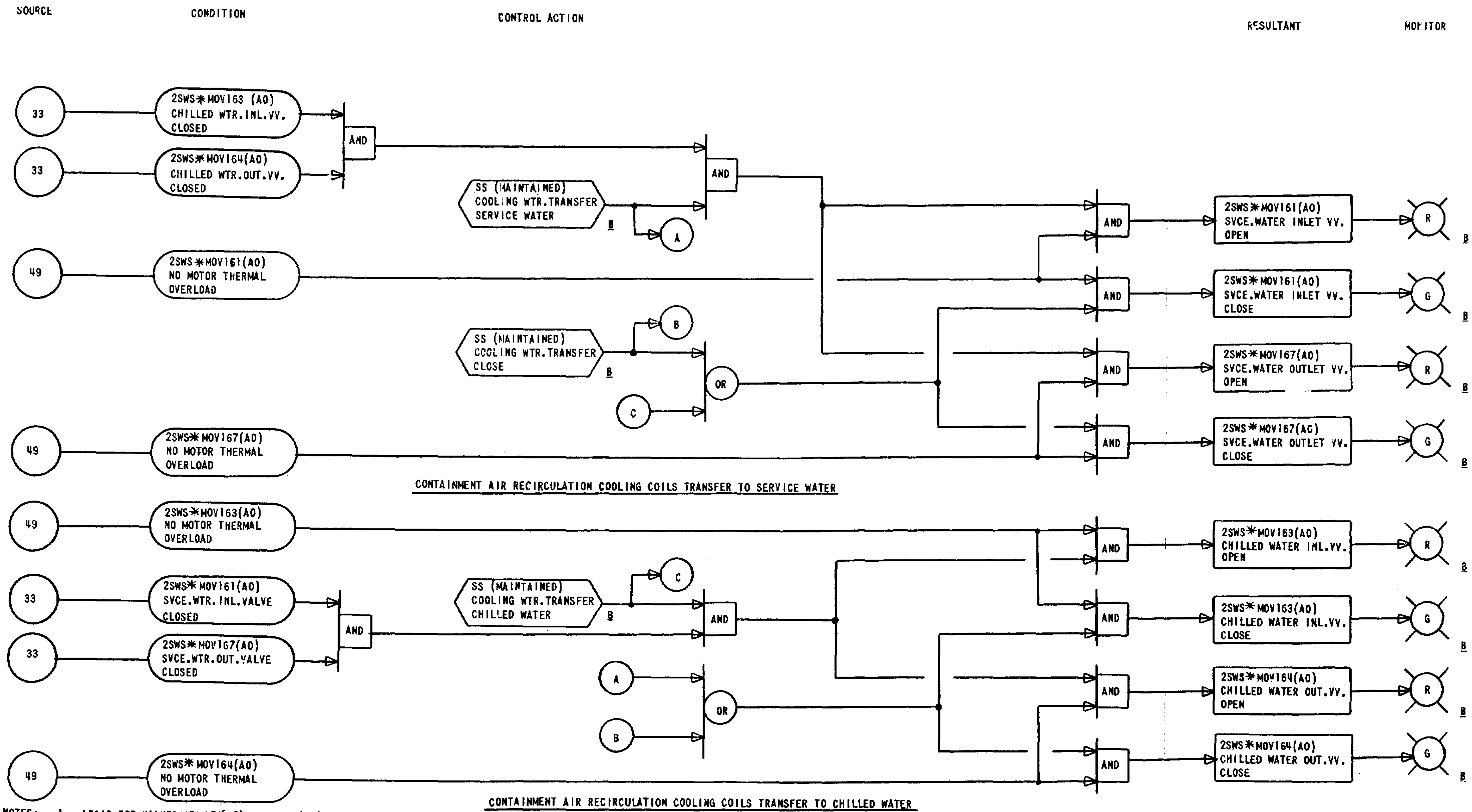
REV 12



NOTES:

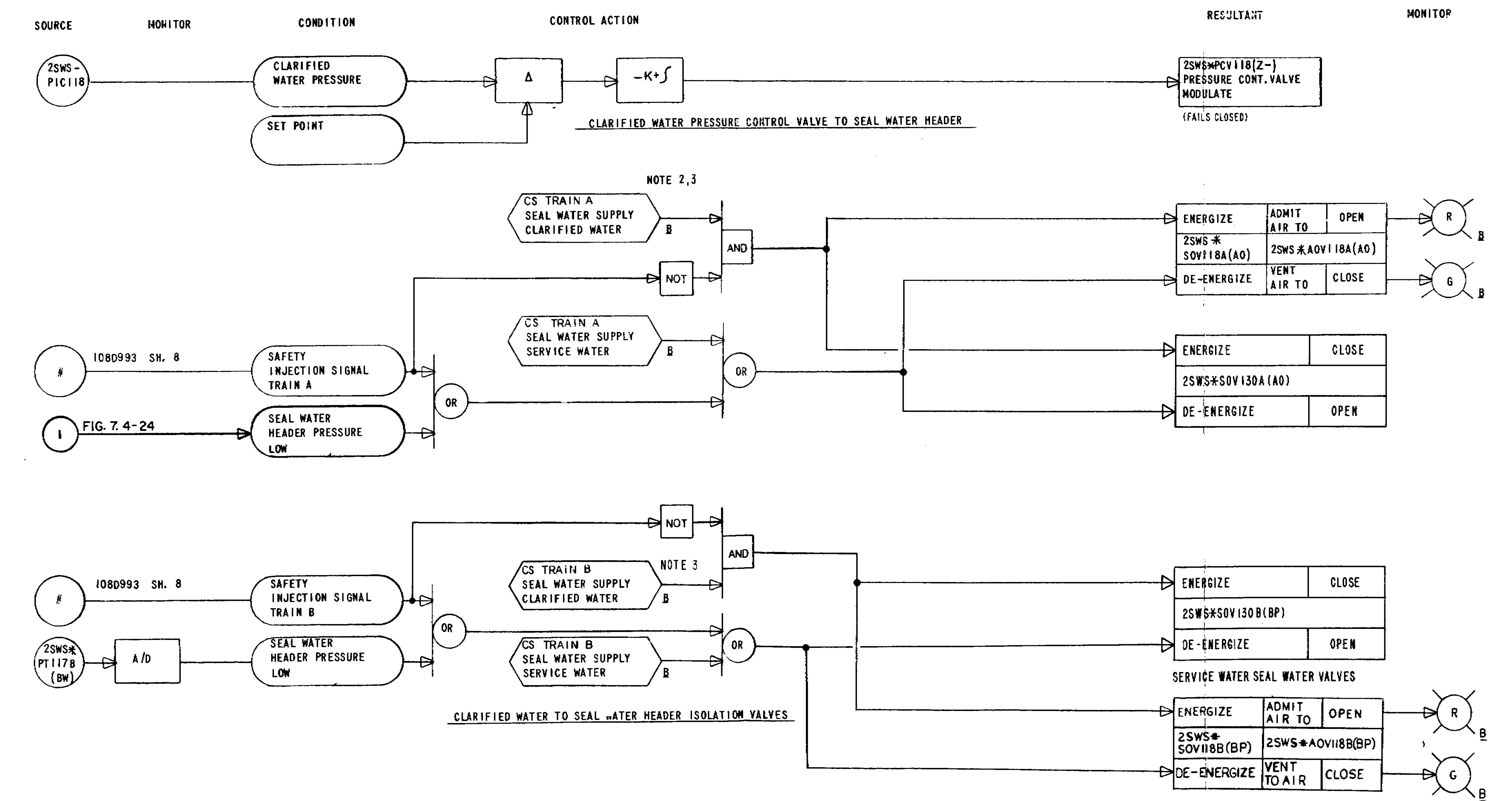
1. LOGIC FOR BACKWASH MOTOR 2SWS*STRM-47(AO) SHOWN.
   LOGIC FOR BACKWASH MOTOR 2SWS*STRM-48(BP) SIMILAR.
2. LOGIC FOR PRESSURE CONTROL VALVE 2SWS*PCV117A(AO) SHOWN
   LOGIC FOR PRESSURE CONTROL VALVE 2SWS*PCV117B(BP) SIMILAR
3. LOGIC FOR ISOLATION VALVE 2SWS*MOV170A(AO) SHOWN.
   LOGIC FOR ISOLATION VALVE 2SWS*MOV170B(BP) SIMILAR.
4. # BY MANUFACTURER

FIGURE 7.4-24
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES: 1. LOGIC FOR VALVES MOV161(AO), MOV167(AO), MOV163(AO), AND MOV164(AO) SHOWN. LOGIC FOR VALVES MOV160(BP), MOV166(BP), MOV162(BP), AND MOV165(BP) SIMILAR.

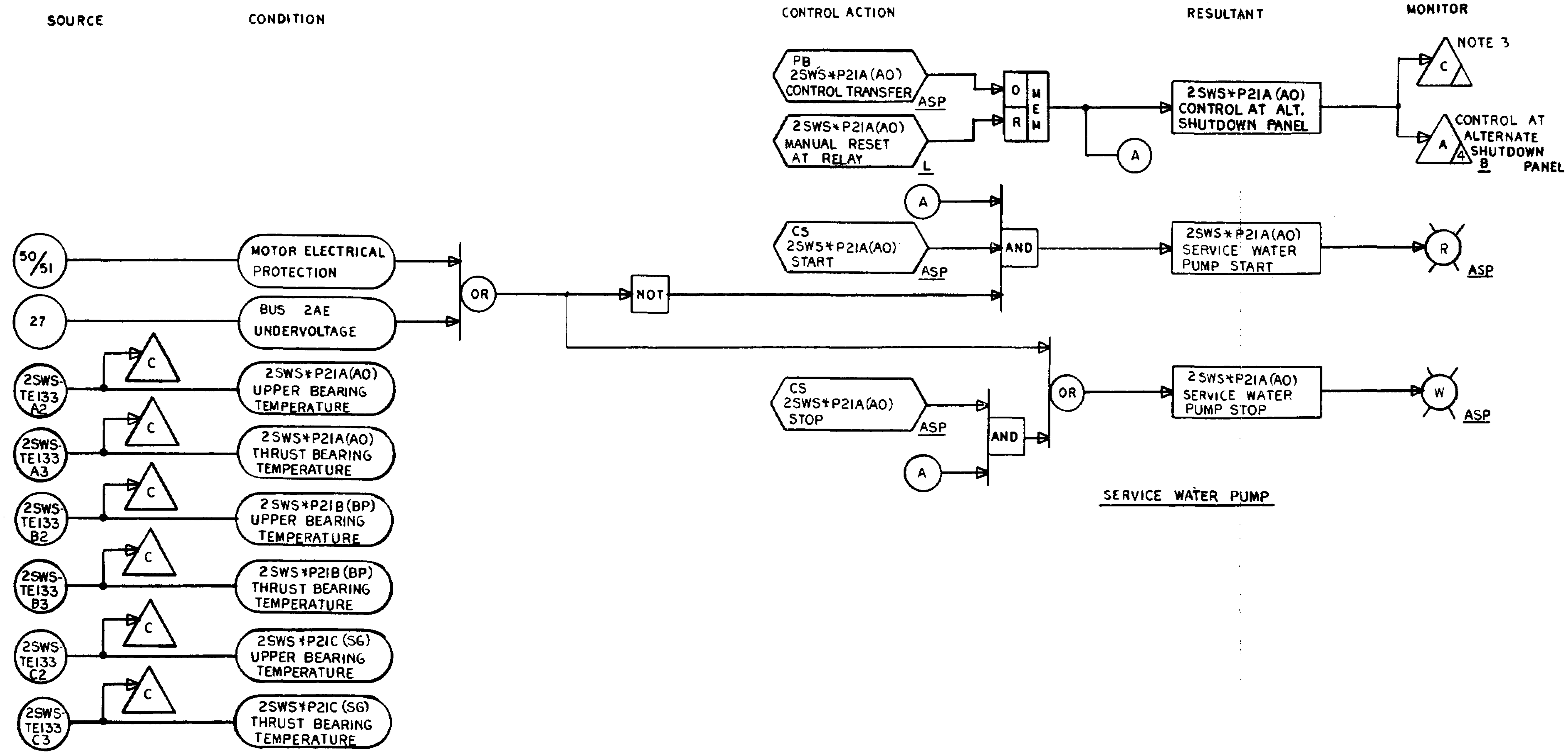
FIGURE 7.4-25
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. # BY MANUFACTURER
2. FOR ADDITIONAL CONTROL SWITCH INTERLOCKS REFER TO FIG. 7.4-24.
3. HOLDING C.S. IN CLARIFIED WATER POSITION WITH NO SIS SIGNAL WILL ALLOW RETURN TO CLARIFIED WATER FROM SERVICE WATER AND RESET PRESSURE PERMISSIVE.

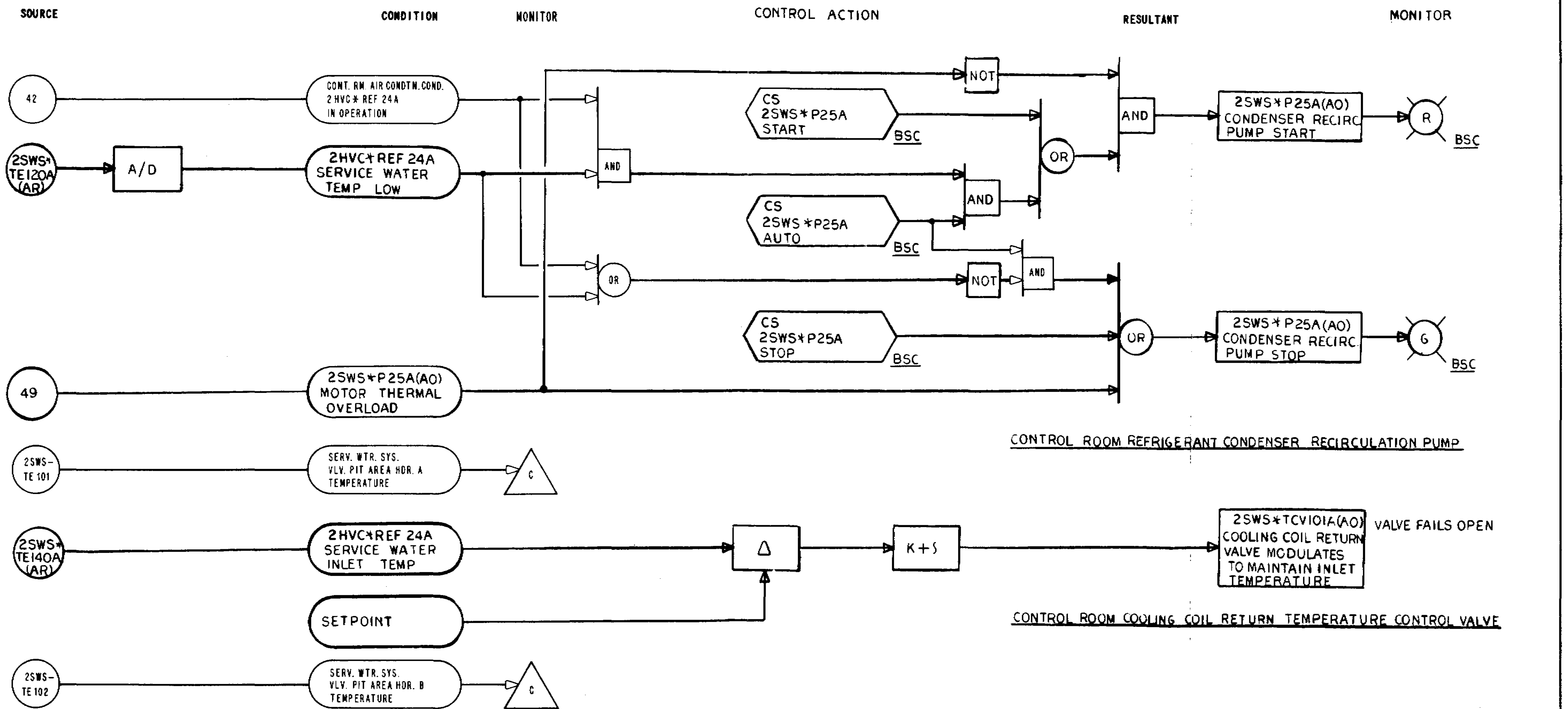
FIGURE 7.4-26
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. SEE ADDITIONAL CONTROL OF 2SWS*P21A(AO) ON FIG. 7.4-18.
2. ONLY THE MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
3. ONE COMPUTER POINT IS COMMON FOR ALL ALTERNATE SHUTDOWN PANEL INPUTS.

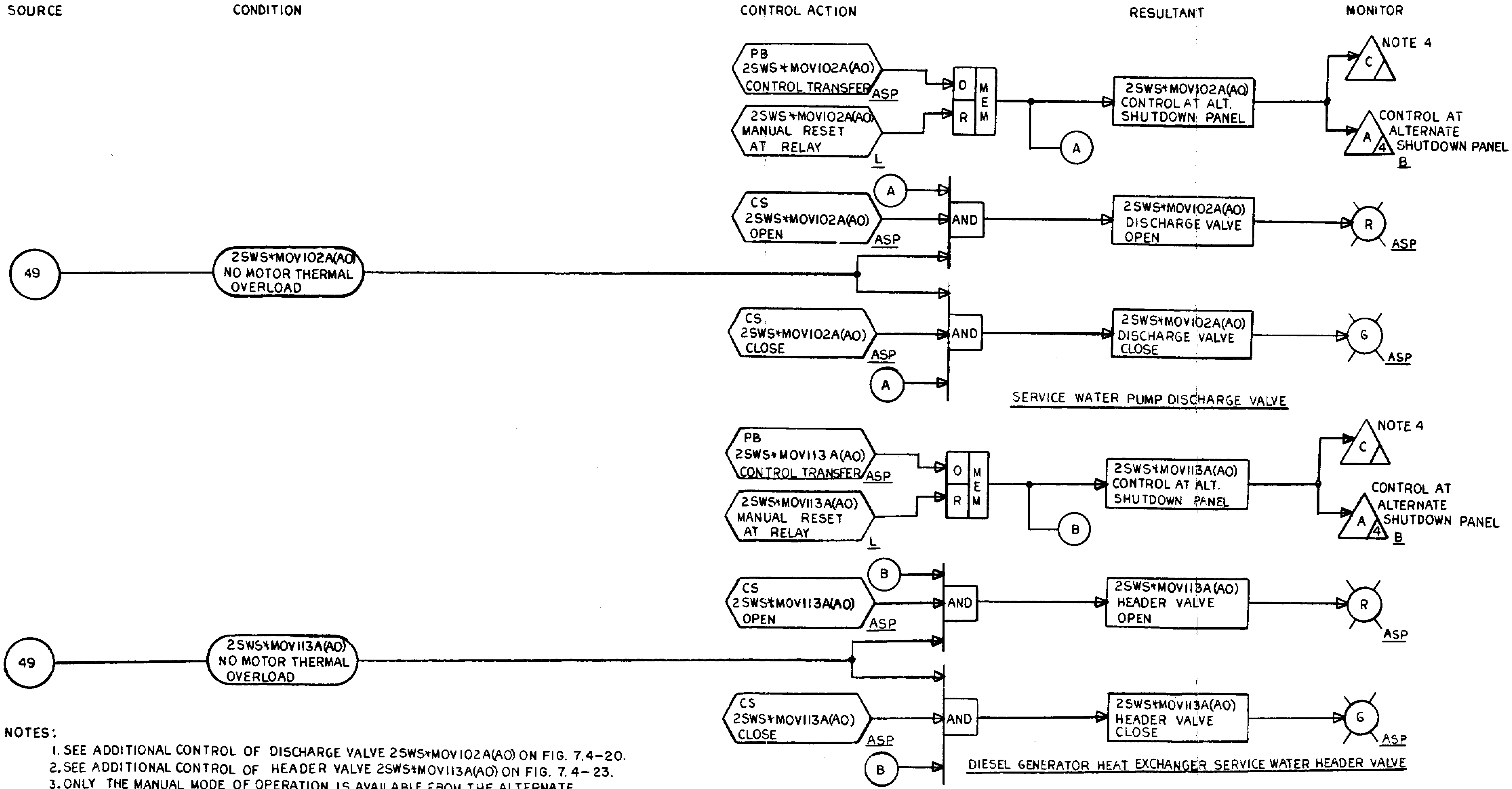
FIGURE 7.4-26A
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES

1. CONDENSER RECIRCULATION PUMP 2SWS*P25A(AO) SHOWN, CONDENSER RECIRCULATION PUMP 2SWS*P25B(BP) SIMILAR.
2. TEMPERATURE CONTROL VALVE 2SWS*TCV101A(AO) SHOWN, TEMPERATURE CONTROL VALVE 2SWS*TCV101B(BP) SIMILAR.

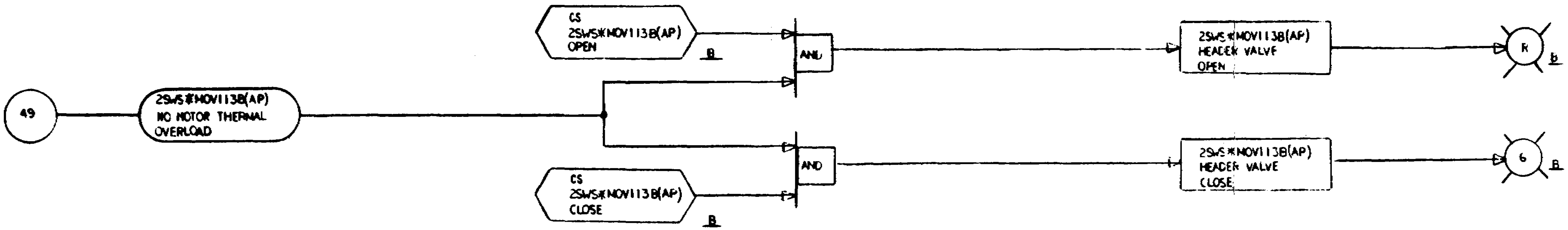
FIGURE 7.4-26B
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. SEE ADDITIONAL CONTROL OF DISCHARGE VALVE 2SWS*MOV102A(AO) ON FIG. 7.4-20.
2. SEE ADDITIONAL CONTROL OF HEADER VALVE 2SWS*MOV113A(AO) ON FIG. 7.4-23.
3. ONLY THE MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
4. ONE COMPUTER POINT IS COMMON FOR ALL ALTERNATE SHUTDOWN PANEL INPUTS.

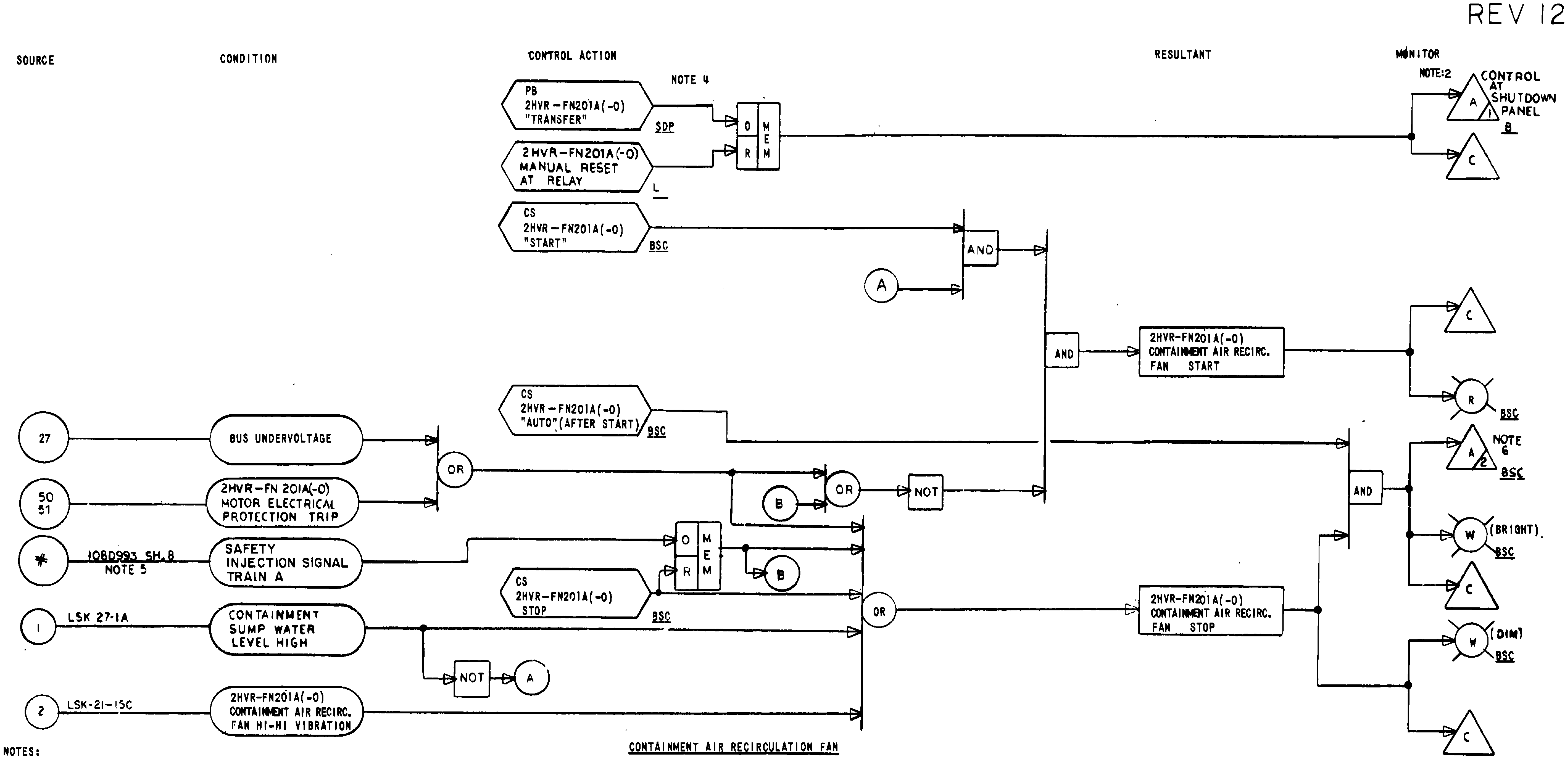
FIGURE 7.4-26C
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



DIESEL GENERATOR HEAT EXCHANGER SERVICE WATER HEADER VALVE
2SWS*MOV113B(AP)
(NOTE 1)

NOTES: 1. HEADER VALVE 2SWS*MOV 113B(AP) SHOWN.
HEADER VALVE 2SWS MOV 113C(BO) SIMILAR.

FIGURE 7.4-26D
LOGIC DIAGRAM
SERVICE WATER SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

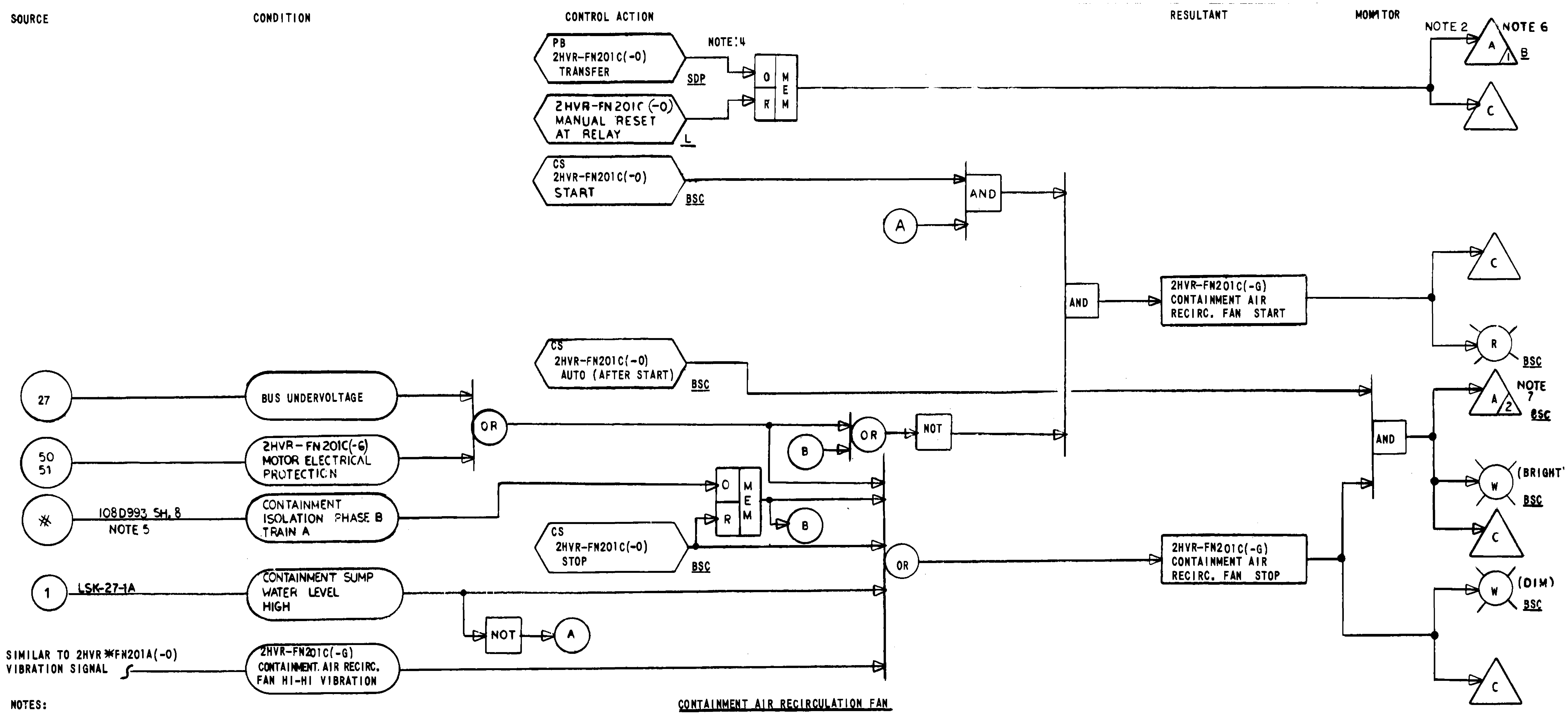


NOTES:

1. LOGIC FOR CONTAINMENT AIR RECIRCULATION FAN 2HVR-FN201A(-0) ON BUS 2N SHOWN.
   LOGIC FOR FAN 2HVR-FN201B(-P) ON BUS 2P SIMILAR.
2. ANNUNCIATORS AND COMPUTER INPUTS COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. CONTROL FROM BUILDING SERVICE PANEL SHOWN.
   CONTROL FROM SHUTDOWN PAPEL SIMILAR.
4. FAN CONTROL FROM THE BUILDING SERVICE CONTROL
   PANEL IS ONLY AVAILABLE WHEN THE CONTROL
   TRANSFER SWITCH IS RESET.
5. # BY WESTINGHOUSE
6. CONTAINMENT AIR RECIRC. FAN AUTO-STOP.

FIGURE 7.4-27
LOGIC DIAGRAM
VENTILATION SYSTEM
CONTAINMENT AIR
RECIRCULATION FANS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 12

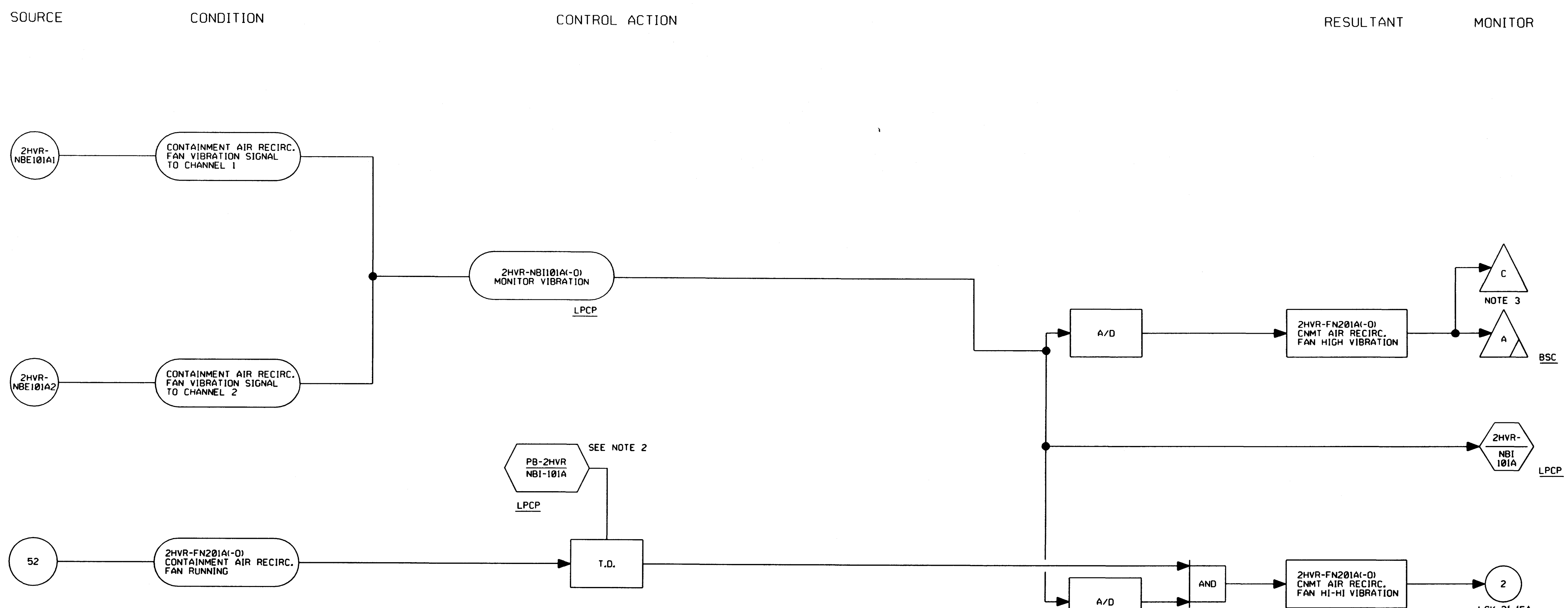


NOTES:

1. LOGIC FOR CONTAINMENT AIR RECIRCULATION FAN 2HVR-FN201C(-G) ON BUS 2N SHOWN. LOGIC FOR FAN 2HVR-FN201C(-G) ON BUS 2P SIMILAR.
2. ANNUNCIATOR AND COMPUTER INPUT COMMON TO ALL SHUTDOWN PANEL TRANSFER SWITCHES.
3. CONTROL FROM BUILDING SERVICE PANEL SHOWN. CONTROL FROM SHUTDOWN PANEL SIMILAR.
4. FAN CONTROL FROM THE BUILDING SERVICE CONTROL PANEL IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER SWITCH IS RESET.
5. *BY WESTINGHOUSE
6. CONTROL AT SHUTDOWN PANEL
7. CONTAINMENT AIR RECIRC. FAN AUTO-STOP

FIGURE 7.4-28
LOGIC DIAGRAM
VENTILATION SYSTEM
CONTAINMENT AIR
RECIRCULATION FANS
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REV. 21



CONTAINMENT AIR RECIRCULATION FAN VIBRATION MONITOR

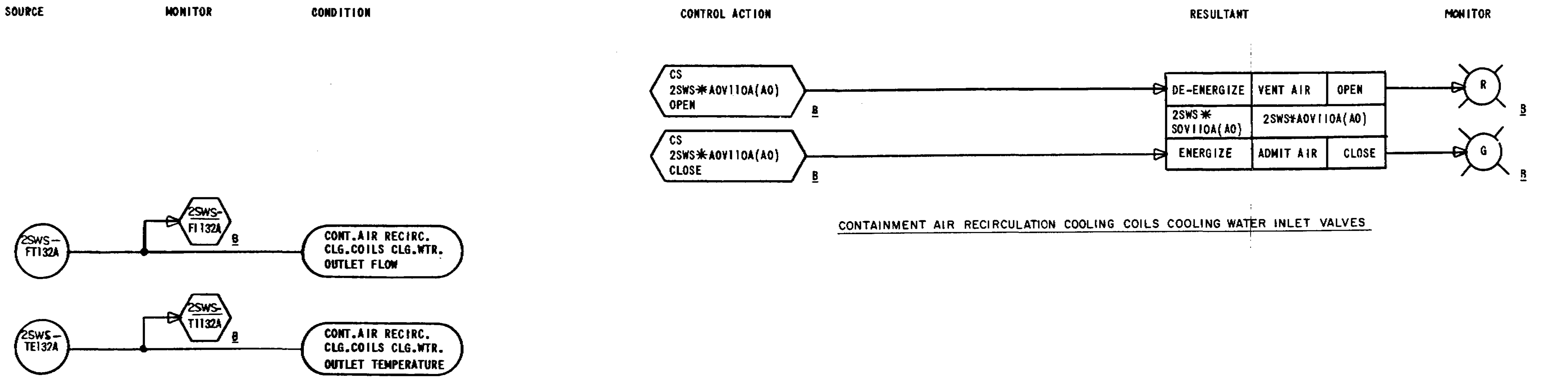
NOTES:

1. CONTAINMENT AIR RECIRCULATION FAN 2HVR-FN201A(-O) IS SHOWN. CONTAINMENT AIR RECIRCULATION FANS 2HVR-FN201B(-P) AND FN201C(-G) VIBRATION MONITORS ARE SIMILAR.
2. PUSH BUTTON USED ON START-UP ONLY TO ACTIVATE TIME DELAY OF TRIP SIGNAL.
3. CONTAINMENT AIR RECIRCULATION FAN VIBRATION HIGH

UFSAR FIGURE 7.4-29

LOGIC DIAGRAM
VENTILATION SYSTEM
CONTAINMENT AIR
RECIRCULATION FANS

BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



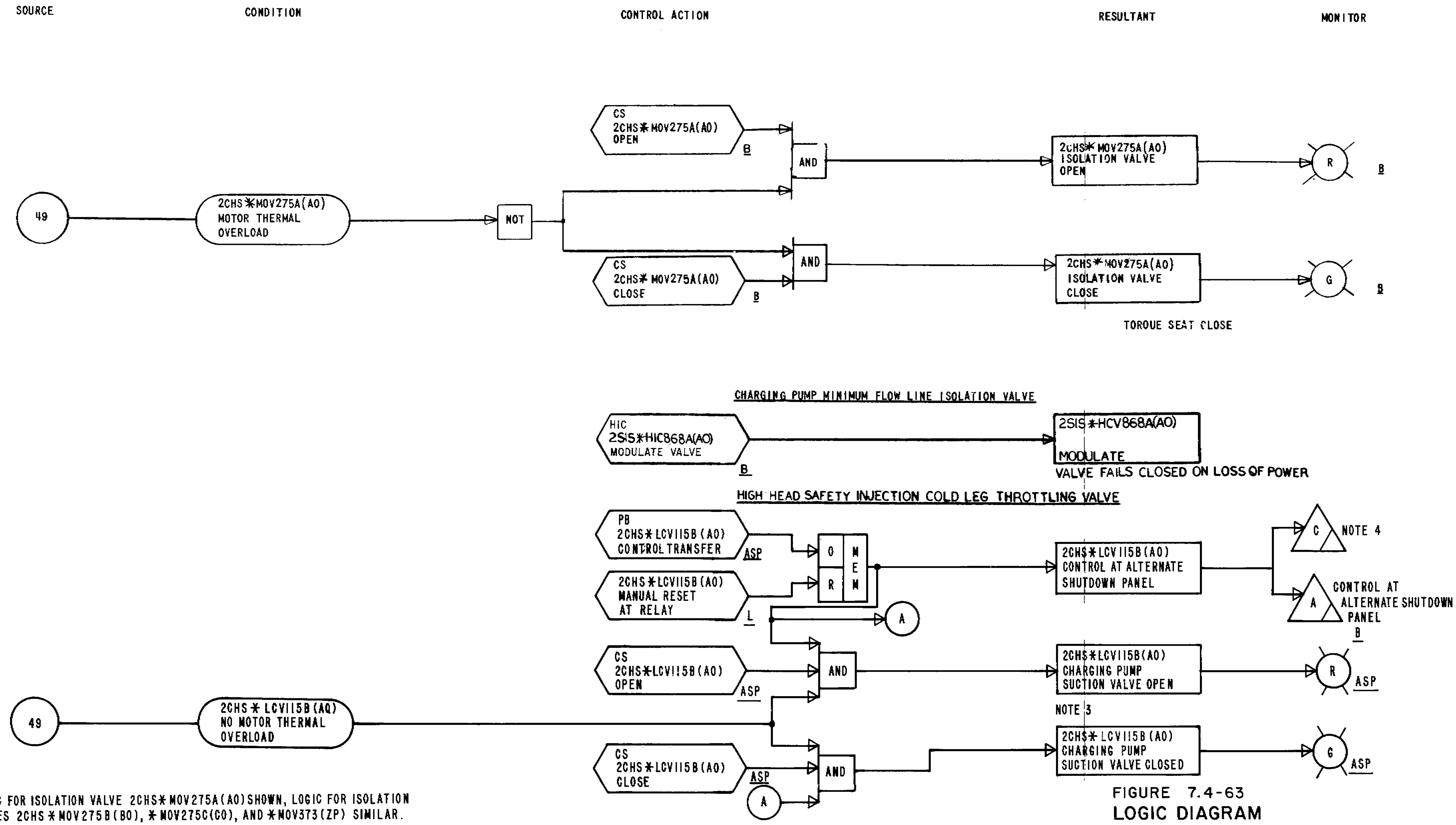
NOTES:

1. INLET VALVE 2SWS*AOV110A(AO) IS SHOWN.
   INLET VALVE 2SWS*AOV110B(BP) AND 2SWS*AOV110C(SO) SIMILAR.

2. ASSOCIATED INSTRUMENTS:

2HVR*CLC201A	2HVR*CLC201B	2HVR*CLC201C
2SWS-FT132A	2SWS-FT132B	2SWS-FT132C
2SWS-TE132A	2SWS-TE132B	2SWS-TE132C

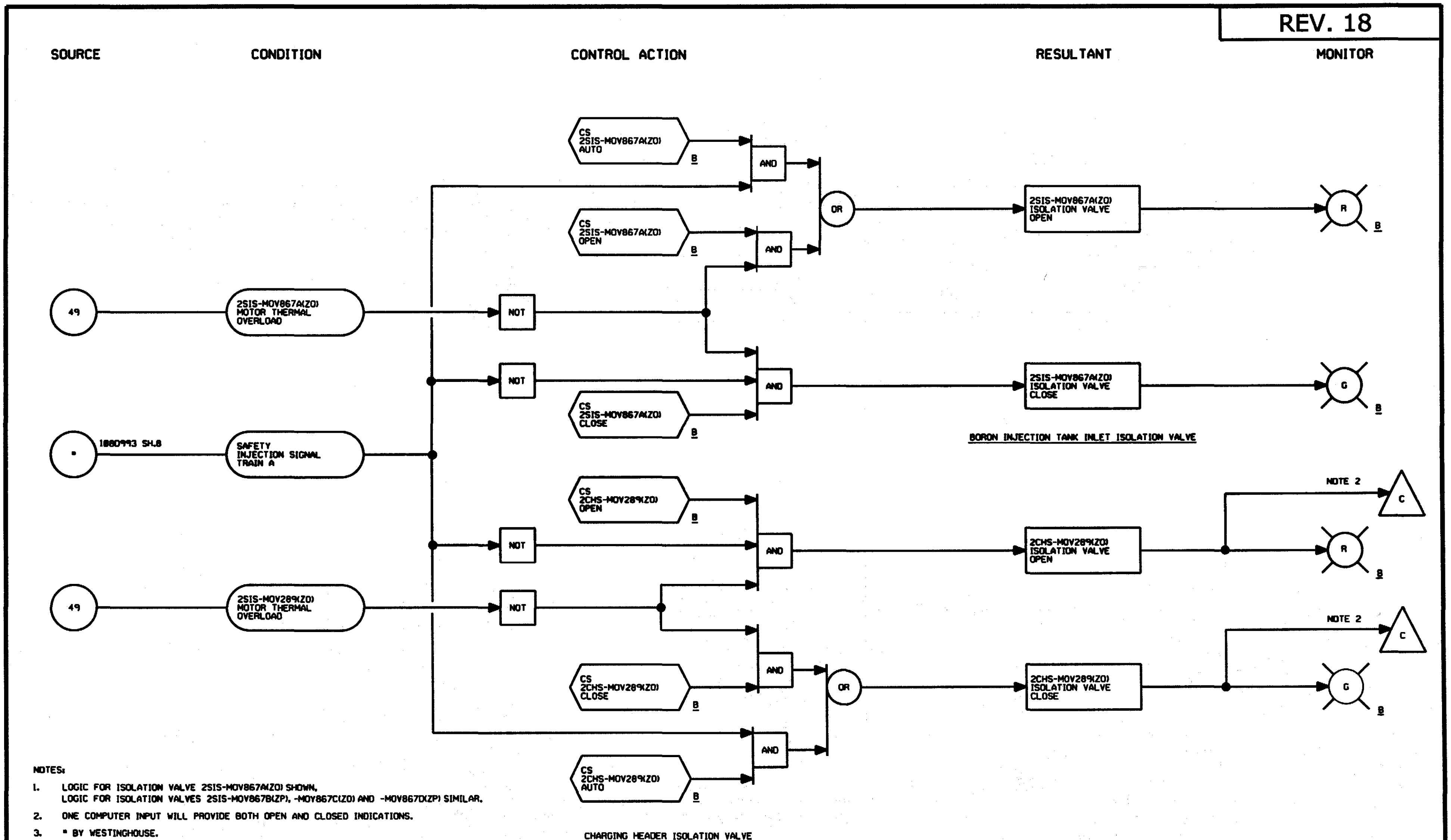
FIGURE 7.4-30
LOGIC DIAGRAM
VENTILATION SYSTEM
CONTAINMENT AIR
RECIRCULATION FANS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES

1. LOGIC FOR ISOLATION VALVE 2CHS✱MOV275A(AO) SHOWN, LOGIC FOR ISOLATION VALVES 2CHS✱MOV275B(BO), ✱MOV275C(CO), AND ✱MOV373(ZP) SIMILAR.
2. LOGIC FOR THROTTLING VALVE 2SIS✱HCV868A(AO) SHOWN, LOGIC FOR THROTTLING VALVE 2SIS✱HCV868B(BP) SIMILAR.
3. SEE ADDITIONAL CONTROL OF SUCTION VALVE 2CHS✱LCV 115B(AO) ON FIG. 7.4-65.
4. ONE COMPUTER INPUT IS COMMON FOR ALL ALTERNATE SHUTDOWN PANEL INPUTS.

FIGURE 7.4-63
LOGIC DIAGRAM
SAFETY INJECTION CONTROL VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



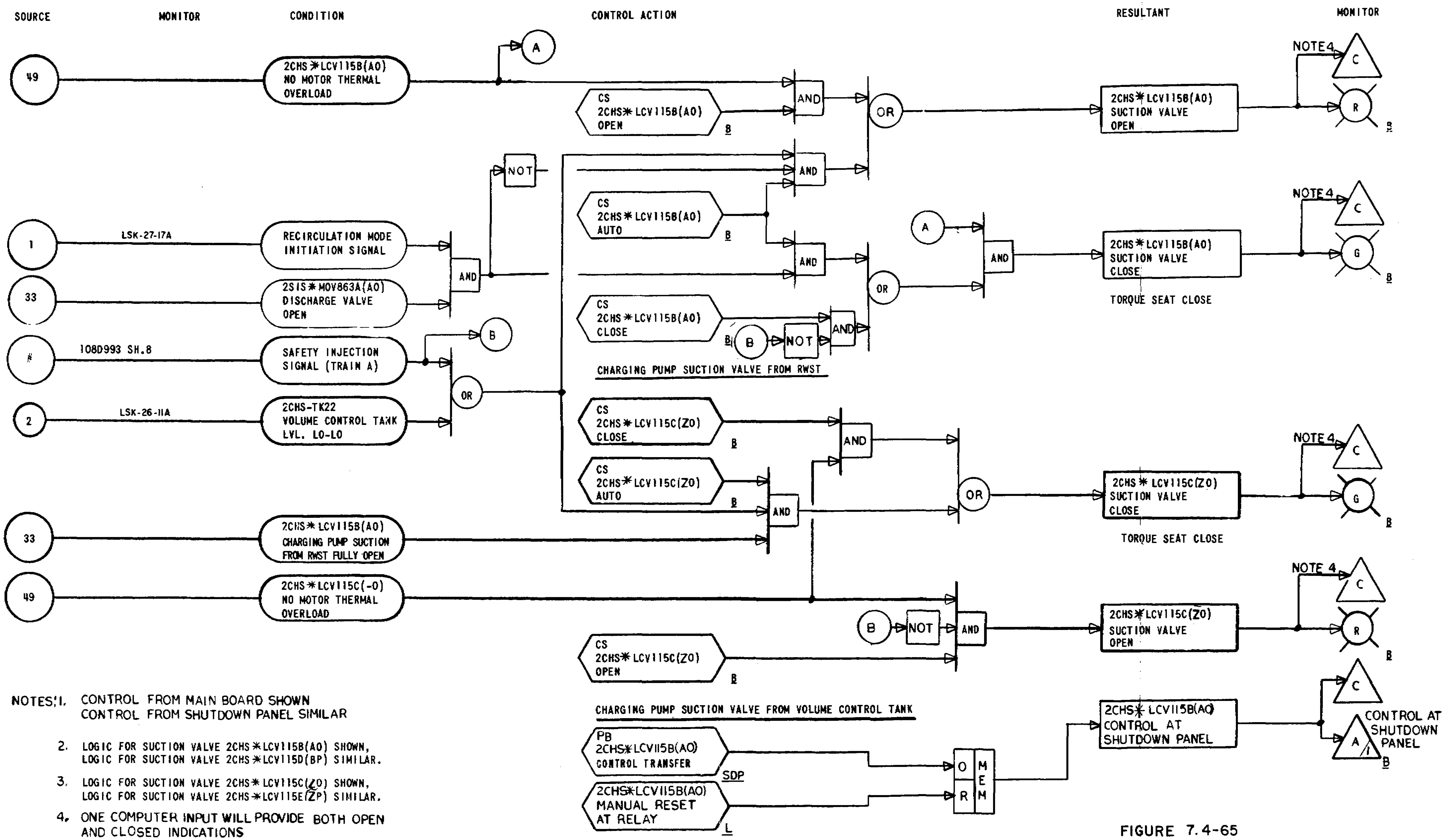
NOTES:

1. LOGIC FOR ISOLATION VALVE 2SIS-MOV867A(ZO) SHOWN,
   LOGIC FOR ISOLATION VALVES 2SIS-MOV867B(ZP), -MOV867C(ZO) AND -MOV867D(ZP) SIMILAR.
2. ONE COMPUTER INPUT WILL PROVIDE BOTH OPEN AND CLOSED INDICATIONS.
3. * BY WESTINGHOUSE.

FIGURE 7.4-64

LOGIC DIAGRAM SAFETY INJECTION CONTROL VALVES

BEAVER VALLEY POWER STATION UNIT No. 2
FINAL SAFETY ANALYSIS REPORT



NOTES: 1. CONTROL FROM MAIN BOARD SHOWN
CONTROL FROM SHUTDOWN PANEL SIMILAR

2. LOGIC FOR SUCTION VALVE 2CHS*LCV115B(AO) SHOWN, LOGIC FOR SUCTION VALVE 2CHS*LCV115D(BP) SIMILAR.

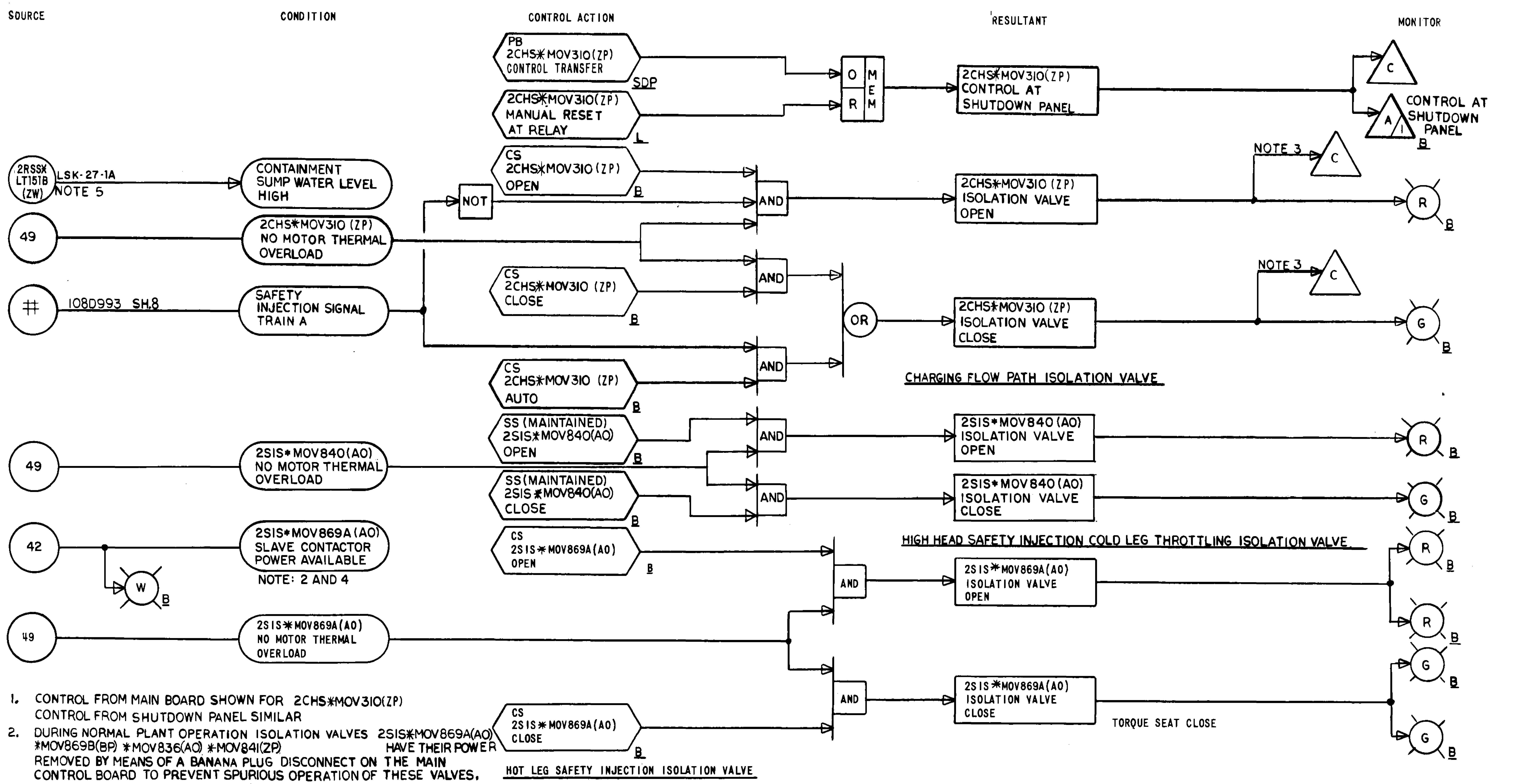
3. LOGIC FOR SUCTION VALVE 2CHS*LCV115C(ZO) SHOWN, LOGIC FOR SUCTION VALVE 2CHS*LCV115E(ZP) SIMILAR.

4. ONE COMPUTER INPUT WILL PROVIDE BOTH OPEN AND CLOSED INDICATIONS

5. SEE ADDITIONAL CONTROL OF SUCTION VALVE 2CHS *LCV115B ON FIG. 7.4-63.

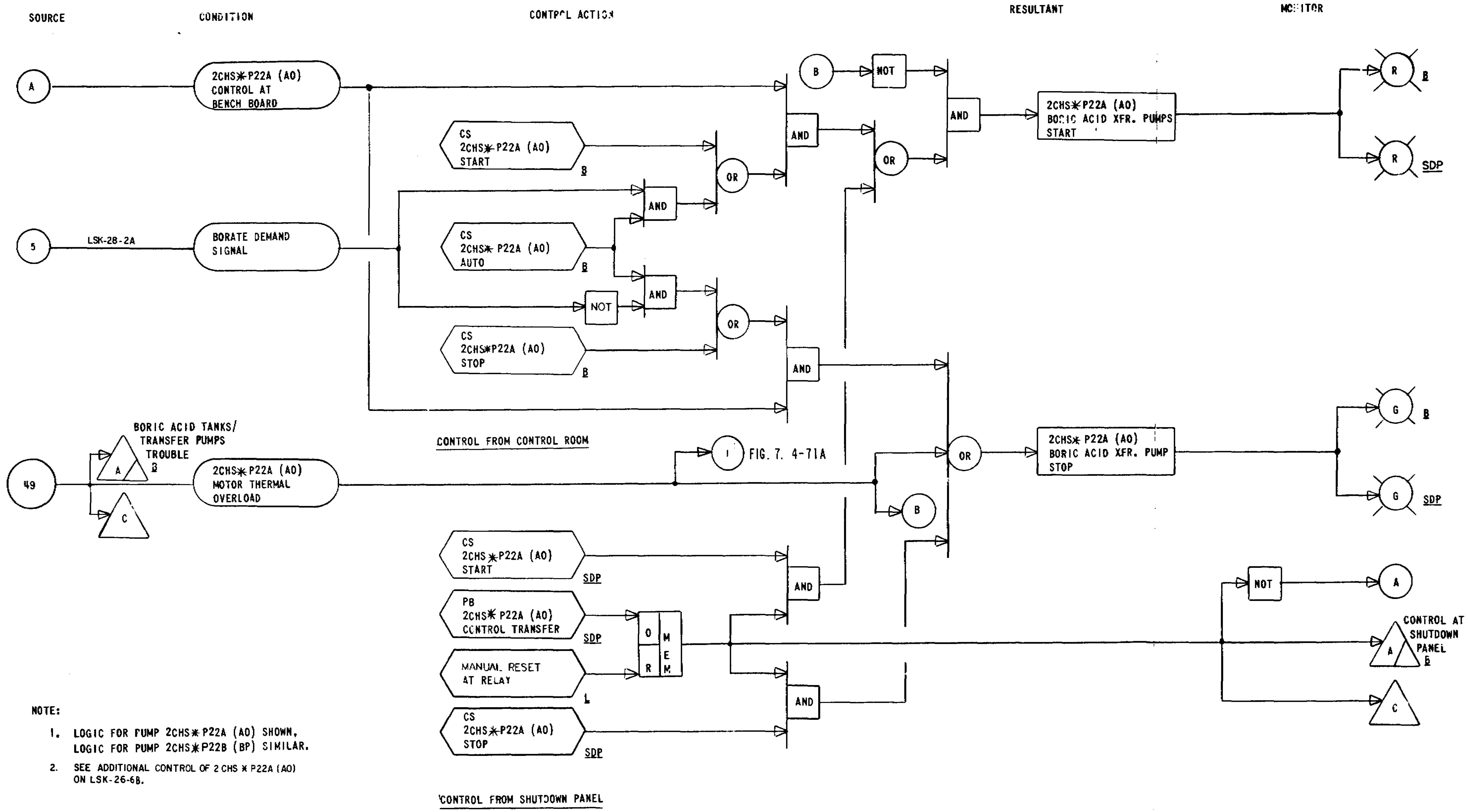
FIGURE 7.4-65
LOGIC DIAGRAM
SAFETY INJECTION CONTROL VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12



1. CONTROL FROM MAIN BOARD SHOWN FOR 2CHS✱MOV310(ZP) CONTROL FROM SHUTDOWN PANEL SIMILAR
2. DURING NORMAL PLANT OPERATION ISOLATION VALVES 2SIS✱MOV869A(AO) ✱MOV869B(BP) ✱MOV836(AO) ✱MOV841(ZP) HAVE THEIR POWER REMOVED BY MEANS OF A BANANA PLUG DISCONNECT ON THE MAIN CONTROL BOARD TO PREVENT SPURIOUS OPERATION OF THESE VALVES.
3. ONE COMPUTER INPUT WILL PROVIDE BOTH OPEN AND CLOSE INDICATIONS
4. LOGIC FOR ISOLATION VALVE 2SIS✱MOV869A(AO) SHOWN, LOGIC FOR ISOLATION VALVES 2SIS✱MOV869B(BP) ✱MOV836(AO) AND ✱MOV841(ZP) SIMILAR
5. MOTOR SUPPLY BREAKER IS SHUNT TRIPPED ON CONTAINMENT SUMP WATER LEVEL HIGH FOR 2CHS✱MOV310 (ZP)

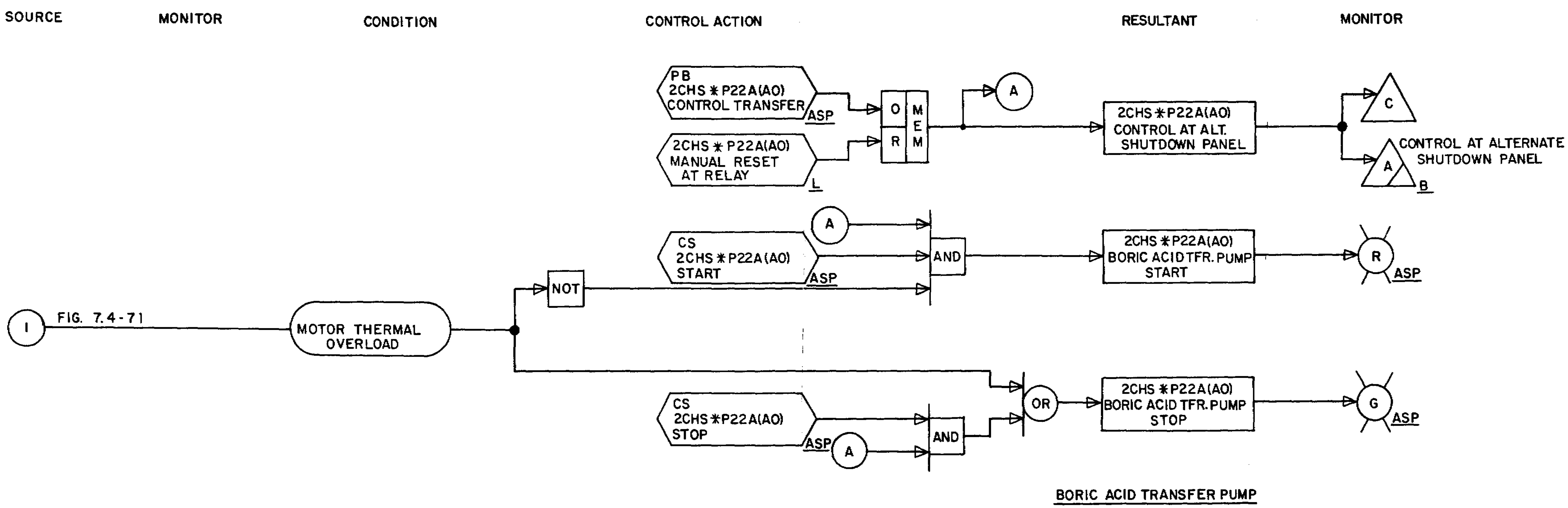
FIGURE 7.4-66
LOGIC DIAGRAM
SAFETY INJECTION CONTROL VALVES
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTE:

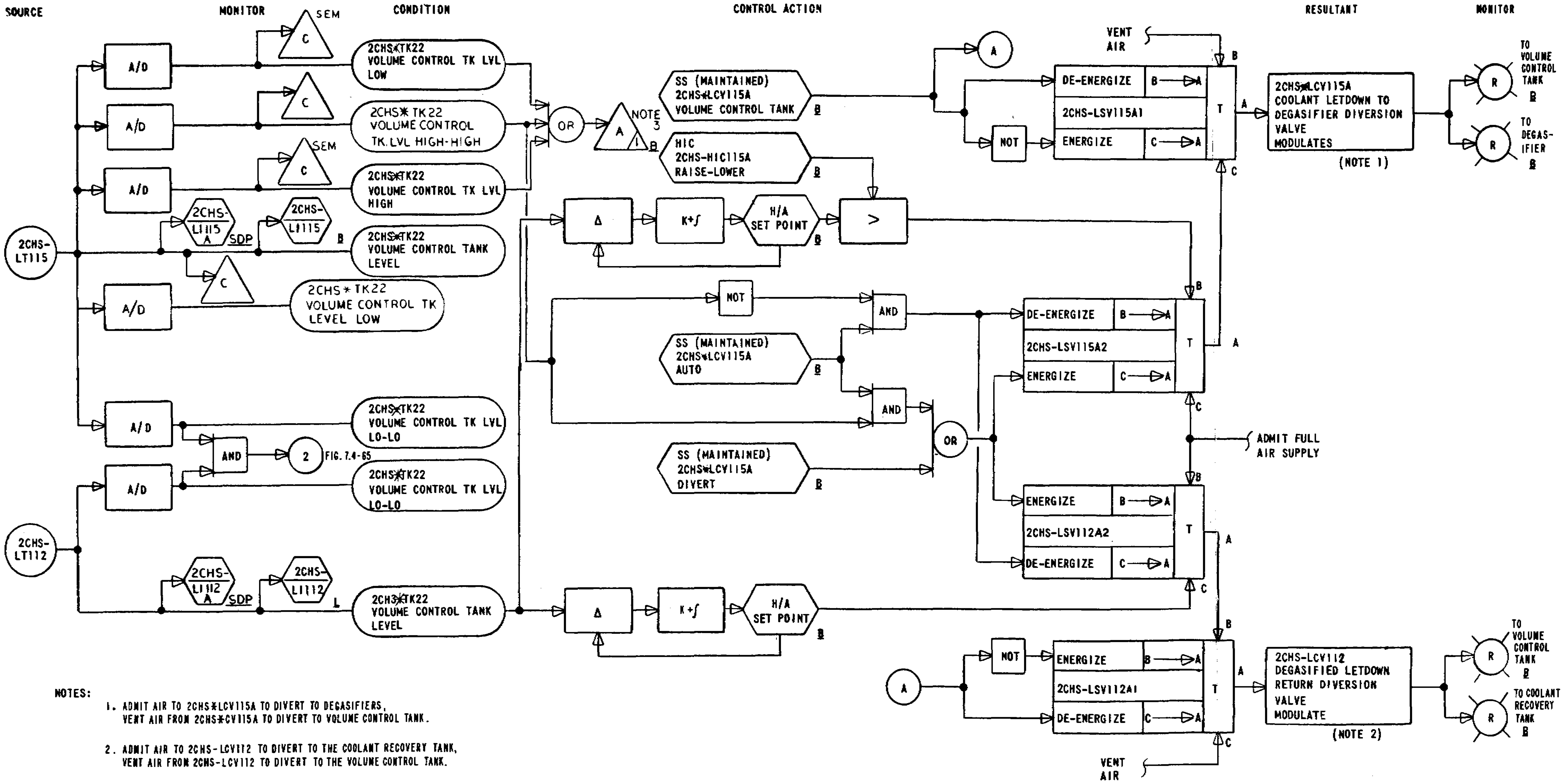
1. LOGIC FOR PUMP 2CHS*P22A (AO) SHOWN, LOGIC FOR PUMP 2CHS*P22B (BP) SIMILAR.
2. SEE ADDITIONAL CONTROL OF 2 CHS * P22A (AO) ON LSK-26-6B.

FIGURE 7.4-71
LOGIC DIAGRAM
BORIC ACID TRANSFER PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE ADDITIONAL CONTROLS FOR 2CHS * P22A(AO) ON LSK 26-6A,
2. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.

FIGURE 7.4-71A
LOGIC DIAGRAM
BORIC ACID TRANSFER PUMPS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. ADMIT AIR TO 2CHS*LCV115A TO DIVERT TO DEGASIFIERS, VENT AIR FROM 2CHS*CV115A TO DIVERT TO VOLUME CONTROL TANK.

2. ADMIT AIR TO 2CHS-LCV112 TO DIVERT TO THE COOLANT RECOVERY TANK, VENT AIR FROM 2CHS-LCV112 TO DIVERT TO THE VOLUME CONTROL TANK.

3. VOLUME CONTROL TANK TROUBLE.

FIGURE 7.4-72
LOGIC DIAGRAM
VOLUME CONTROL TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

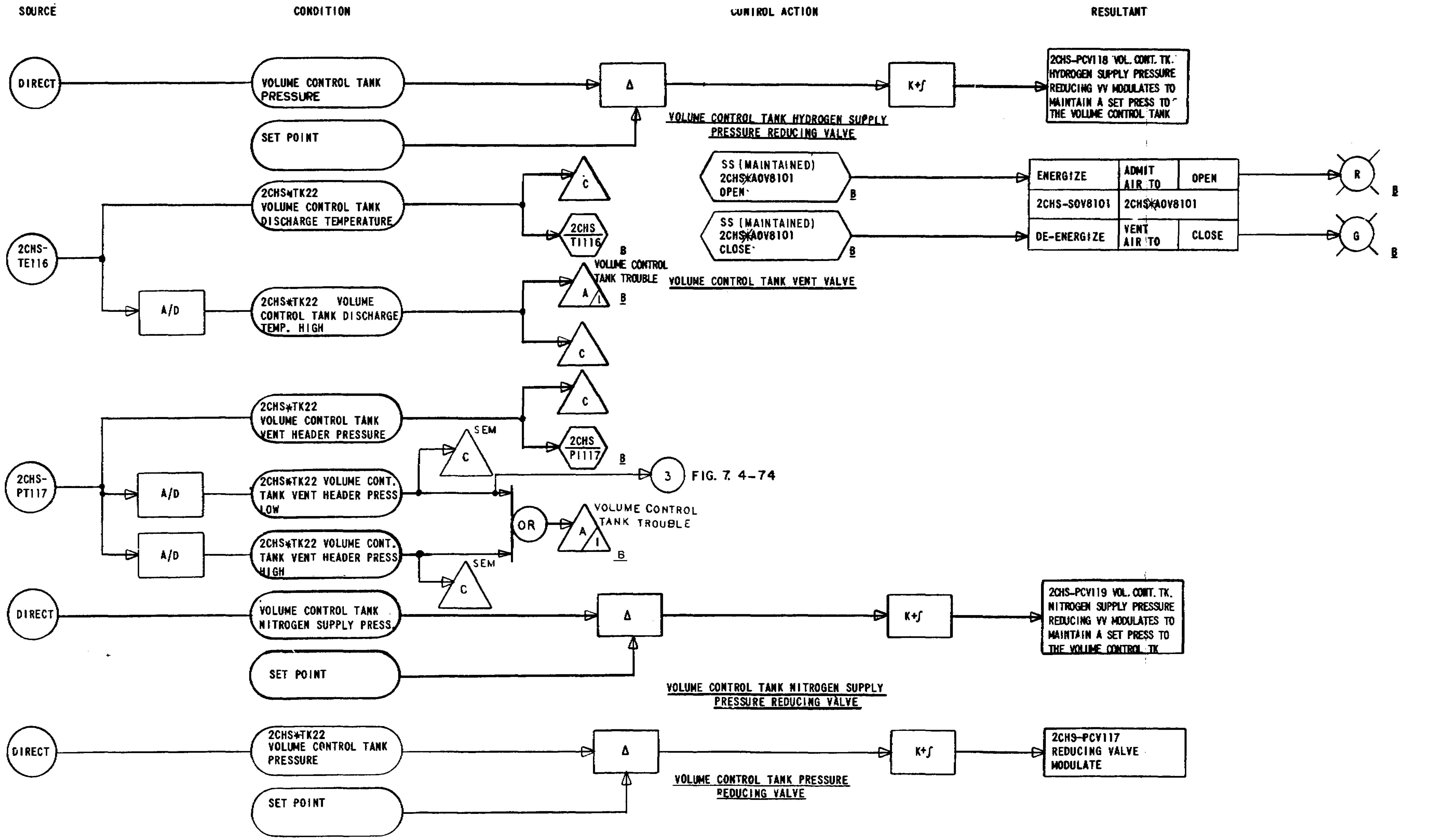


FIGURE 7.4-73
LOGIC DIAGRAM
VOLUME CONTROL TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

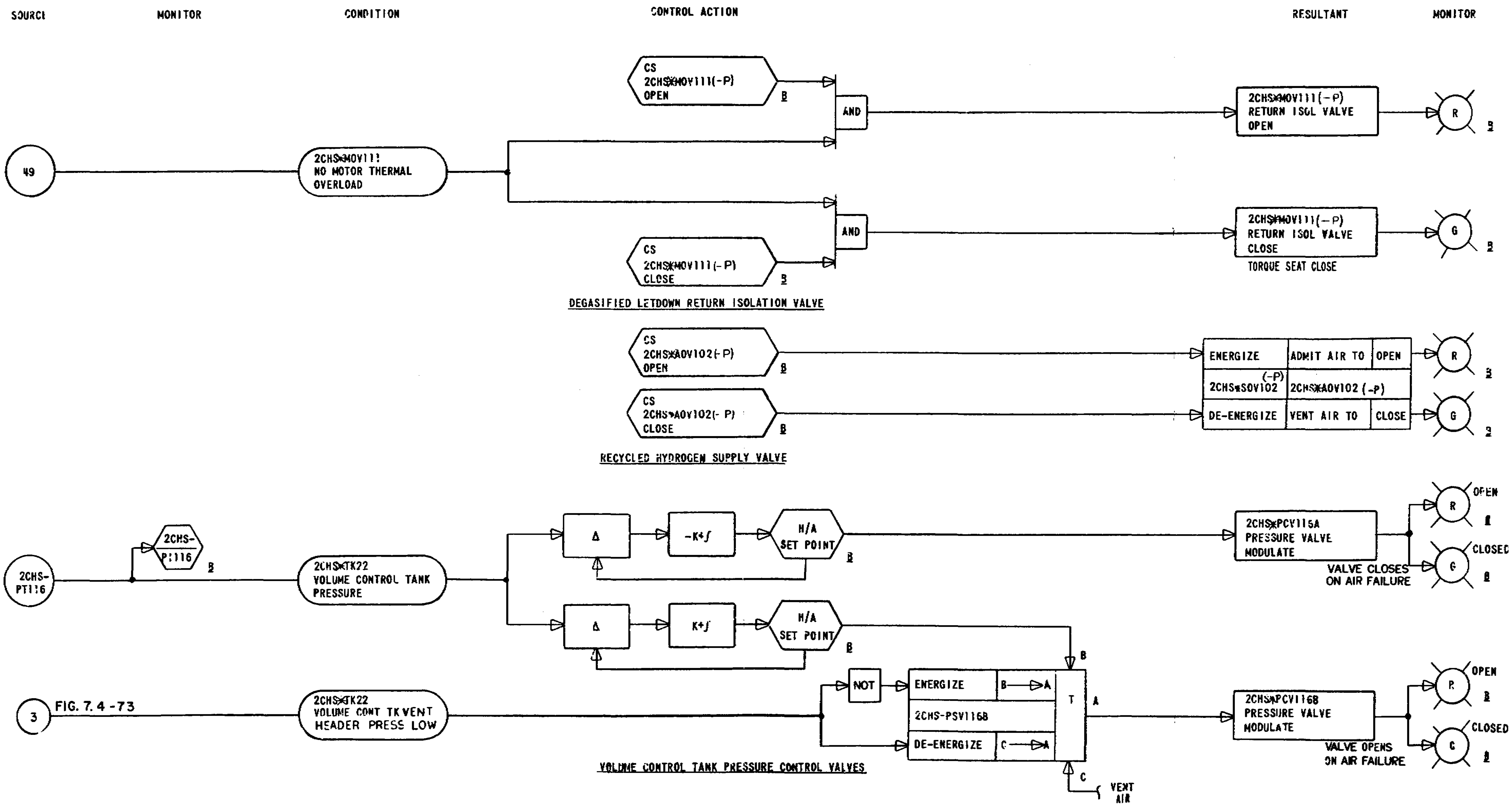


FIGURE 7.4-74
LOGIC DIAGRAM
VOLUME CONTROL TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

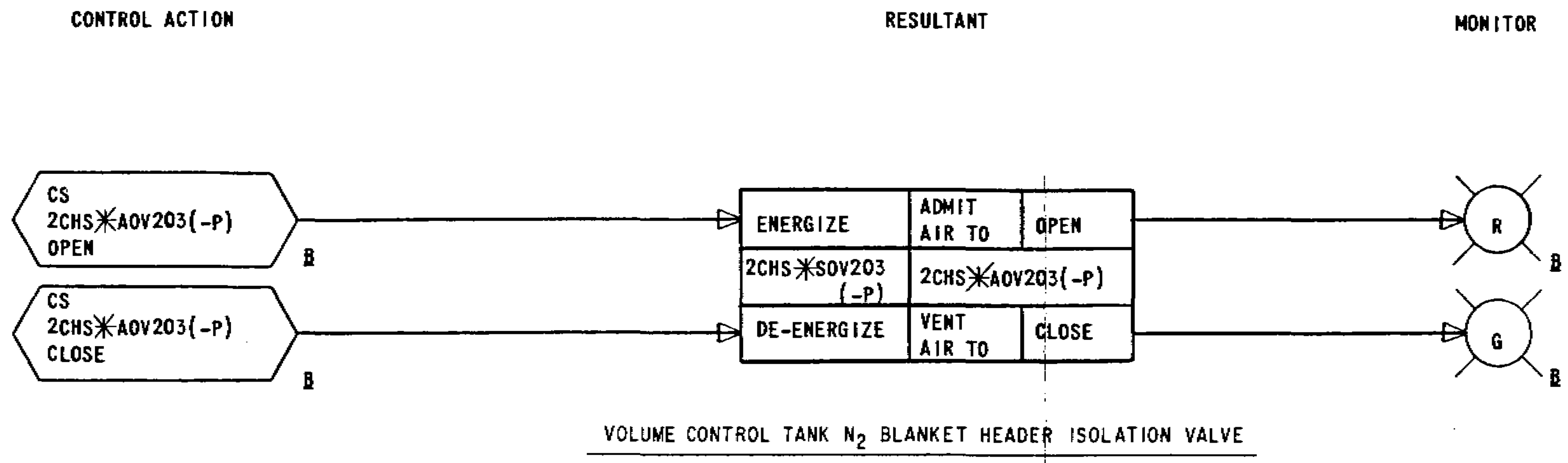
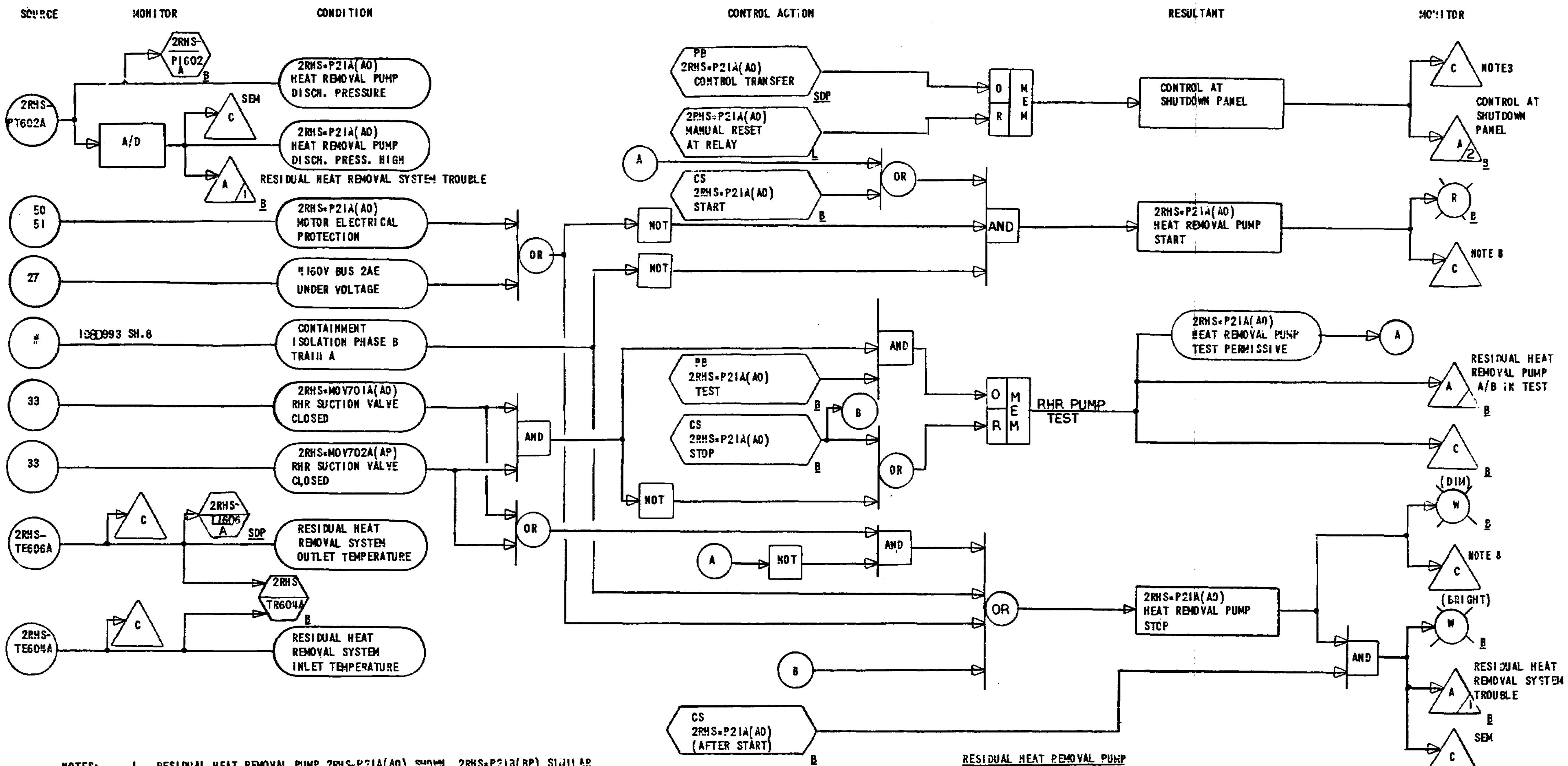


FIGURE 7.4-75
LOGIC DIAGRAM
VOLUME CONTROL TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

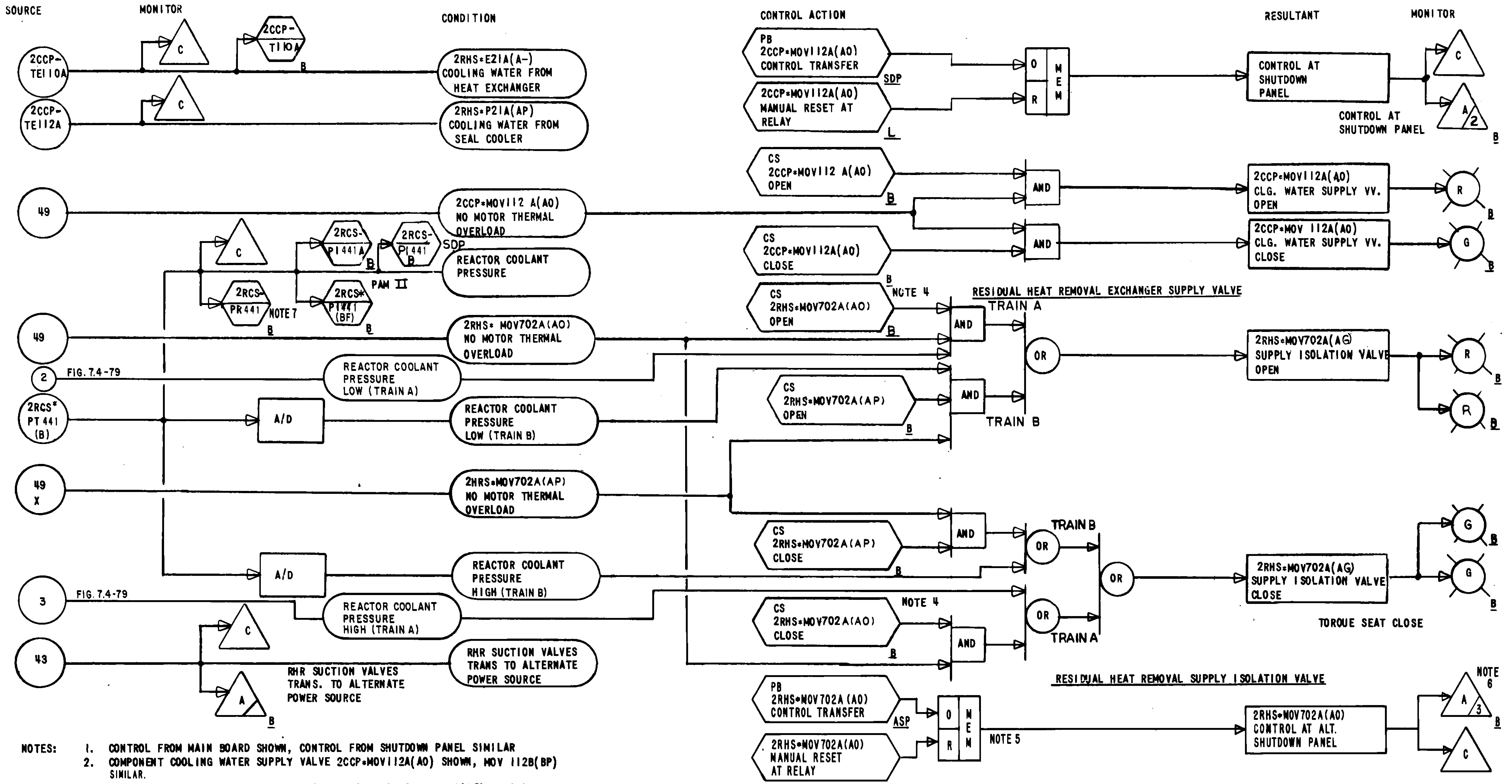
1. RESIDUAL HEAT REMOVAL PUMP 2RHS*P21A(AO) SHOWN, 2RHS*P21B(BP) SIMILAR
2. CONTROL FROM MAINBOARD SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR
3. CONTROL AT THE MAINBOARD IS ONLY AVAILABLE WHEN THE CONTROL TRANSFER IS RESET
4. ANNUNCIATOR AND COMPUTER POINTS ARE COMMON TO ALL EQUIPMENT TRANSFERS
5. ASSOCIATED EQUIPMENT

FLOW PATH A	FLOW PATH B
2RHS*P21A(AO)	2RHS*P21B(BP)
2RHS-PT602A	2RHS-PT602B
2RHS-PI602A	2RHS-PI602B
2RHS-TE604A	2RHS-TE604B
2RHS-TE606A	2RHS-TE606B
2RHS-TI606A	2RHS-TI606B
2RHS-TR604A	2RHS-TR604B

6. #BY WESTINGHOUSE
7. SEE ADDITIONAL CONTROL OF 2RHS*P21A(AO) ON FIG. 7.4-79A
8. ONE COMPUTER INPUT WILL PROVIDE BOTH ON AND OFF INDICATION

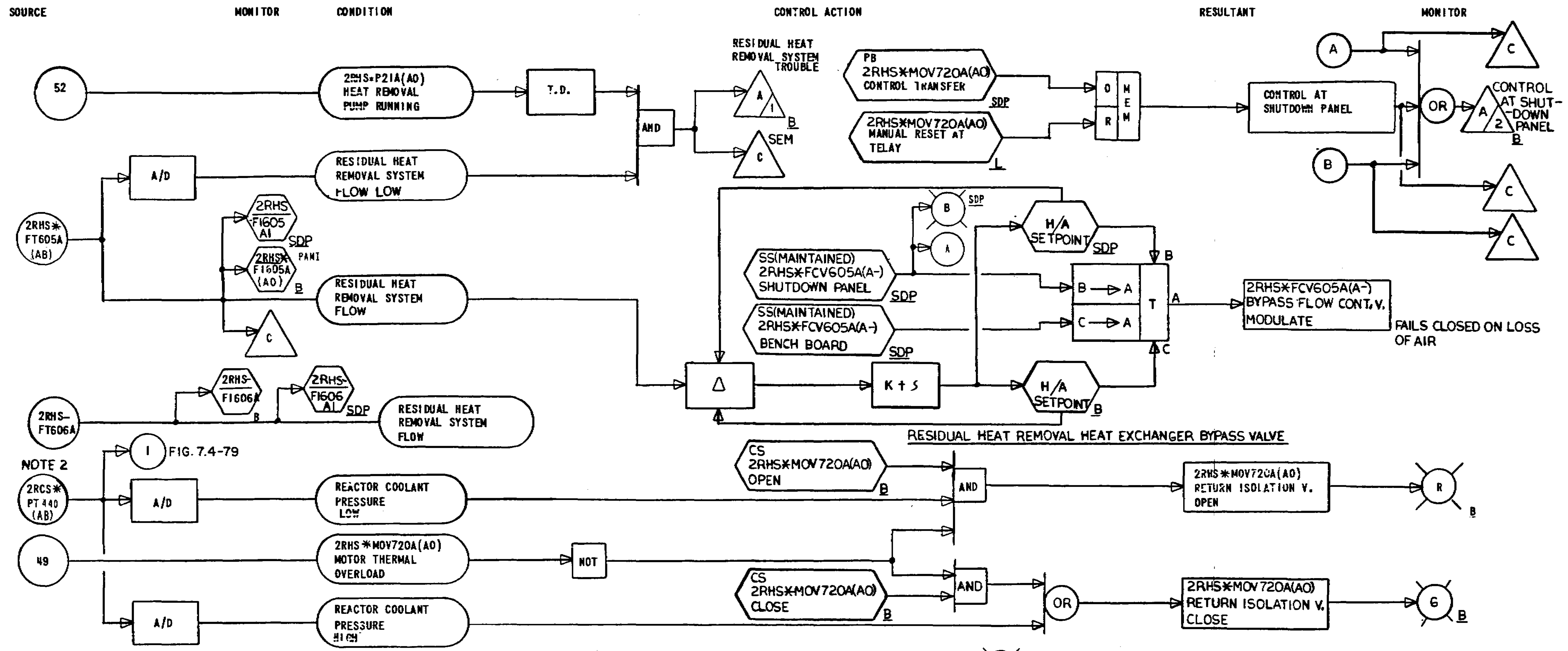
FIGURE 7.4-76
LOGIC DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 12



NOTES:
1. CONTROL FROM MAIN BOARD SHOWN, CONTROL FROM SHUTDOWN PANEL SIMILAR
2. COMPONENT COOLING WATER SUPPLY VALVE 2CCP*MOV112A(AO) SHOWN, MOV 112B(BP) SIMILAR.
3. RESIDUAL HEAT REMOVAL SUPPLY ISOLATION VALVE 2RHS*MOV702A(AG) SHOWN 2RHS*MOV701B(BG) SIMILAR
4. TRANSFER OF POWER SUPPLIES IS DONE AT THE TRANSFER BREAKER ASSEMBLIES NEAR RESPECTIVE MCC.
5. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL
6. CONTROLS AT ALTERNATE SHUTDOWN PANEL
7. 2RCS-PR441 ALSO SHOWN ON FIG. 7.4-79
8. SEE FIG. 7.4-79A FOR ADDITIONAL CONTROL OF 2CCP*MOV112A(AO)

FIGURE 7.4-77
LOGIC DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:

1. CONTROL FROM MAIN BOARD SHOWN
   CONTROL FROM SHUTDOWN PANEL SIMILAR
2. RETURN ISOLATION VALVE 2RHS*MOV720B(BP) RECEIVES REACTOR COOLANT PRESSURE SIGNAL FROM 2RCS*PT441(BY)
3. RETURN ISOLATION VALVE 2RHS*MOV720A(AO) SHOWN.
   RETURN ISOLATION VALVE 2RHS*MOV720B(BP) SIMILAR.
4. BYPASS VALVE 2RHS*FCV605A(A-) SHOWN,
   BYPASS VALVE 2RHS*FCV605B(B-) SIMILAR.
5. OUTLET VALVE 2RHS*HCV758A(A-) SHOWN,
   OUTLET VALVE 2RHS*HCV758B(B-) SIMILAR.
6. 2RHS-FT606A RESIDUAL HEAT REMOVAL SYSTEM FLOW SHOWN
   2RHS-FT606B RESIDUAL HEAT REMOVAL SYSTEM FLOW SIMILAR
7. ASSOCIATED EQUIPMENT

FLOW PATH A	FLOW PATH B
2RHS*FCV605A(A-)	2RHS*FCV605B(B-)
2RHS*FT605A(AB)	2RHS*FT605B(BY)
2RHS-FI605AI	2RHS-FI605BI
2RHS*FI605A(AO)	2RHS*FI605B(BF)
2RHS-FT606A	2RHS-FT606B
2RHS-FI606A	2RHS-FI606B
2RHS*MOV720A(AO)	2RHS*MOV720B(BP)
2RCS*PT440(AB)	2RCS*PT441(BY)
2RHS-FI606AI	2RHS-FI606BI

8. SEE ADDITIONAL CONTROL OF 2RHS*MOV720A(AO) ON FIG. 7.4-79A

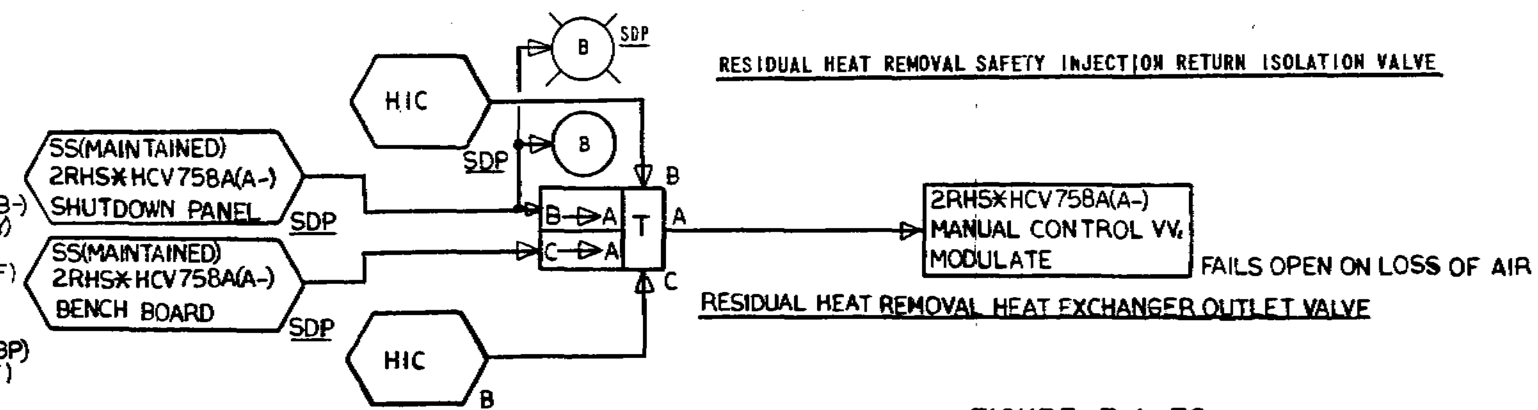
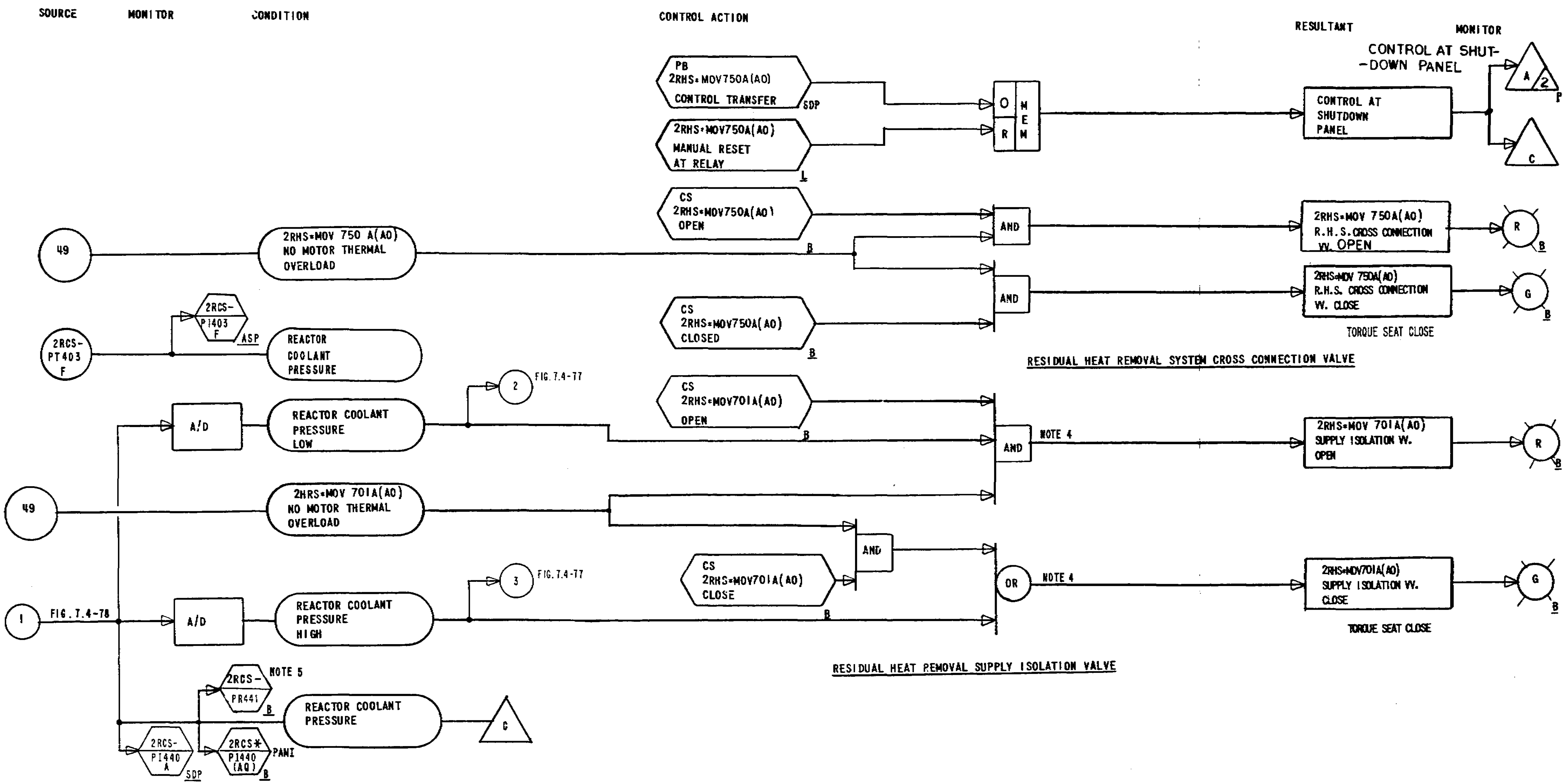
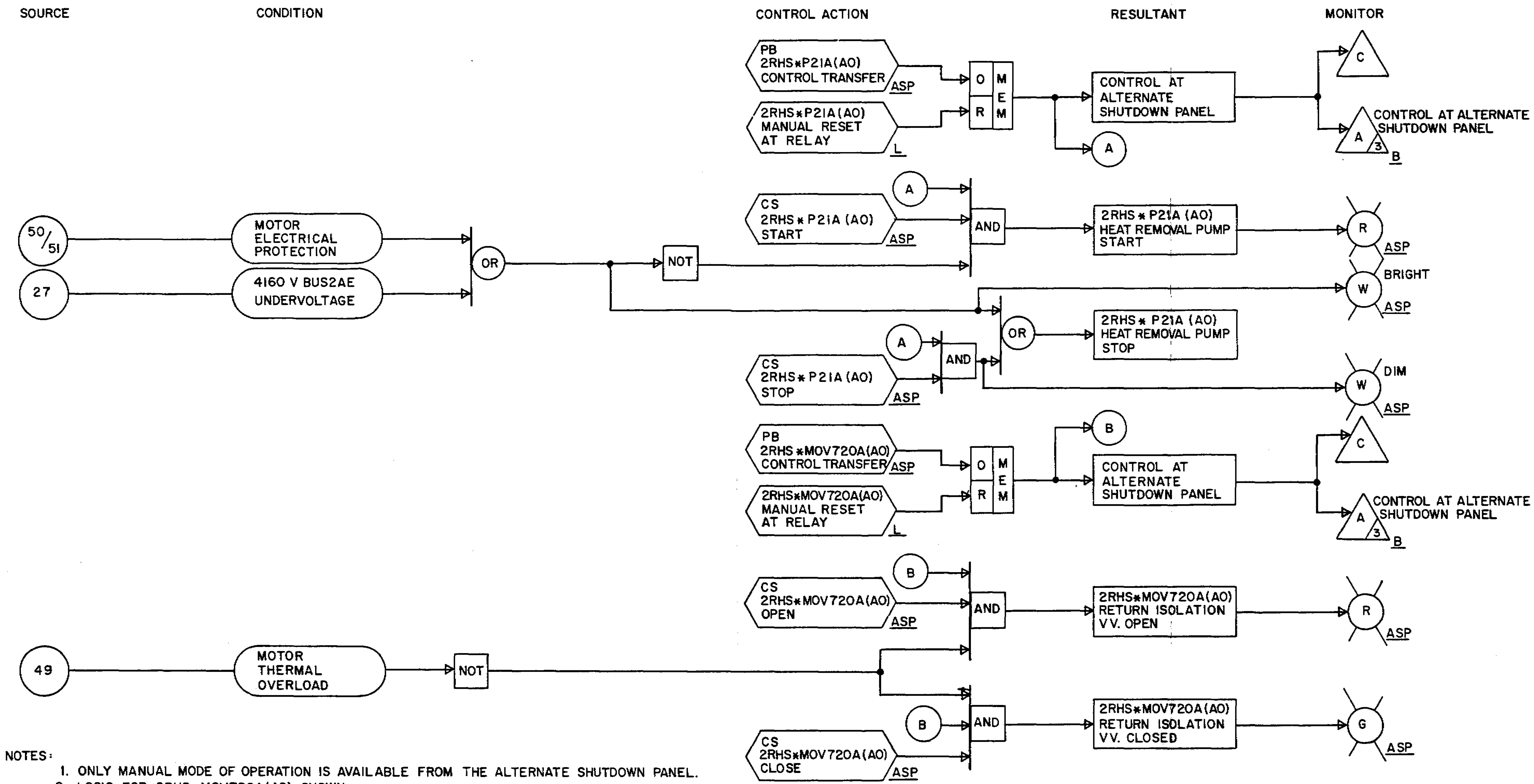


FIGURE 7.4-78
LOGIC DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTE:
1. CONTROL FROM MAIN BOARD SHOWN
   CONTROL FROM SHUTDOWN PANEL SIMILAR
2. RHS CROSS CONNECTION VALVE 2RHS*MOV750A(AO) SHOWN
   RHS CROSS CONNECTION VALVE 2RHS*MOV750B(BP) SIMILAR
3. ISOLATION VALVE 2RHS*MOV701A(AO) SHOWN
   ISOLATION VALVE 2RHS*MOV702B(BP) SIMILAR
4. SEE FIG. 7.4-79A FOR ADDITIONAL CONTROL OF 2RHS*MOV701A(AO)
5. 2RCS-PR441 ALSO SHOWN ON FIG. 7.4-77

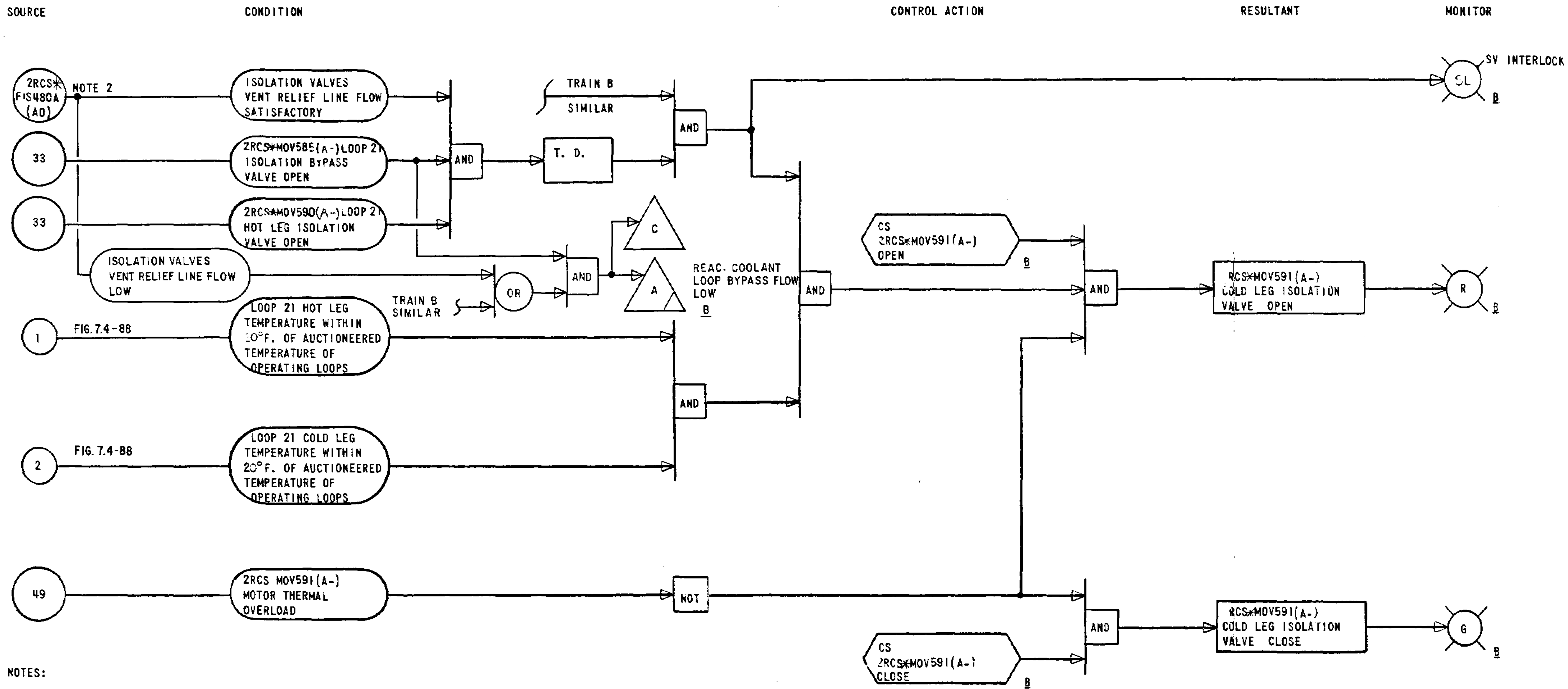
FIGURE 7.4-79
LOGIC DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. ONLY MANUAL MODE OF OPERATION IS AVAILABLE FROM THE ALTERNATE SHUTDOWN PANEL.
2. LOGIC FOR 2RHS*MOV720A(AO) SHOWN.
   LOGIC FOR 2RHS*MOV701A(AO) AND 2CCP*MOV112A(AO) SIMILAR.
3. SEE ADDITIONAL CONTROL OF 2RHS*P21A(AO) ON FIG. 7.4-76.
4. SEE ADDITIONAL CONTROL OF 2RHS*MOV720A(AO) ON FIG. 7.4-78.
5. SEE ADDITIONAL CONTROL OF 2CCP*MOV112A(AO) ON FIG. 7.4-77.

FIGURE 7.4-79A
LOGIC DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

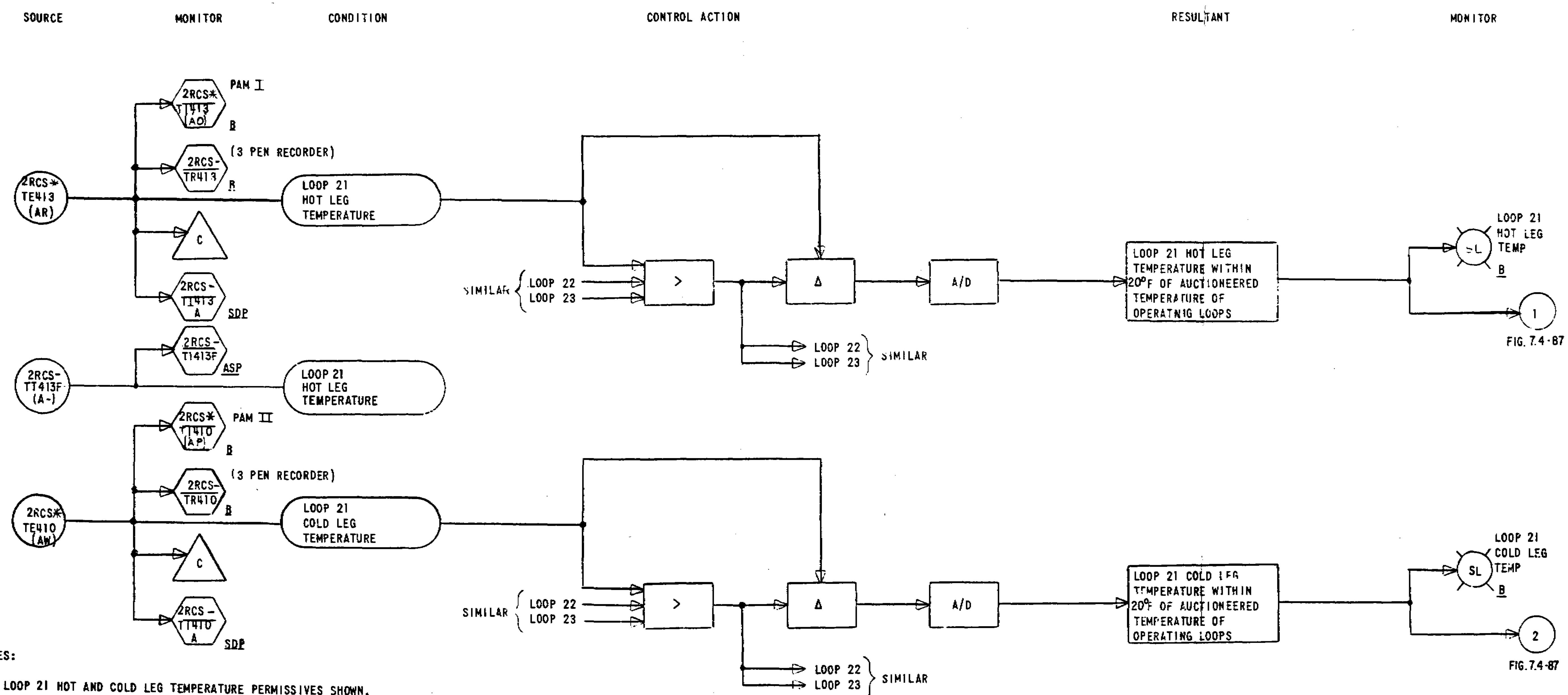


NOTES:

1. LOGIC FOR LOOP 21 COLD LEG ISOLATION VALVE 2RCS*MOV591(A-) SHOWN. LOGIC FOR LOOPS 22 AND 23 COLD LEG ISOLATION VALVES 2RCS*MOV593(B-) AND 2RCS*MOV595(C-) RESPECTIVELY ARE SIMILAR.
2. 2RCS*FIS480A(AO) FOR TRAIN A INTERLOCK SHOWN. 2RCS*FIS480B(BP) FOR TRAIN B INTERLOCK SIMILAR
3. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

LOOP 21	LOOP 22	LOOP 23
2RCS*MOV591A(A-)	2RCS*MOV593(B-)	2RCS*MOV595(C-)
2RCS*FIS480A(AO)	2RCS*FIS481A(BO)	2RCS*FIS482A(CO)
2RCS*FIS480B(AP)	2RCS*FIS481B(BP)	2RCS*FIS482B(CP)

FIGURE 7.4-87
LOGIC DIAGRAM
COLD LEG ISOLATION VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. LOOP 21 HOT AND COLD LEG TEMPERATURE PERMISSIVES SHOWN. LOOPS 22 AND 23 HOT AND COLD LEG TEMPERATURE PERMISSIVES SIMILAR.
2. ASSOCIATED EQUIPMENT IDENTIFICATION NUMBERS:

LOOP 21	LOOP 22	LOOP 23
2RCS*TE413(AR)	2RCS*TE423(BR)	2RCS*TE433(CR)
2RCS*TI413	2RCS-TI423	
2RCS-TR413	2RCS-TR413	2RCS-TR413
2RCS-TI413A	2RCS-TI423A	2RCS-TI433A
2RCS*TE410(AW)	2RCS*TE420(BW)	2RCS*TE430(CW)
2RCS*TI410	2RCS*TI420	
2RCS-TR410	2RCS-TR410	2RCS-TR410
2RCS-TI410A	2RCS-TI420A	2RCS-TI430A
2RCS-TE413F(A)	2RCS-TE423F(B-)	
2RCS-TI413F	2RCS-TI423F	
2RCS-TE410F(A-)	2RCS-TE420F(B-)	
2RCS-TI410F	2RCS-TI420F	

FIGURE 7.4-88
LOGIC DIAGRAM
COLD LEG ISOLATION VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

7.5.1 Introduction

An analysis was conducted to identify the appropriate variables and to establish the appropriate design bases and qualification criterion for instrumentation employed by the operator for monitoring conditions in the reactor coolant system (RCS), the secondary heat removal system, and the reactor containment, including engineered safety functions and the systems employed for attaining a safe shutdown condition.

The instrumentation is used by the operator to monitor Beaver Valley Power Station - Unit 2 (BVPS-2) throughout all operating conditions, including anticipated operational occurrences, accident, and post-accident conditions in accordance with the position stated in Section 1.8 for Regulatory Guide 1.97.

7.5.2 Description of Information Systems

The BVPS-2 safety analyses and evaluations referenced in Chapter 15 and the Westinghouse Owners Group Emergency Response Guidelines define the design basis accident (DBA) event scenarios for which preplanned operator actions are required. Accident monitoring instrumentation is necessary to guide the operator in taking required actions to address these analyzed situations. However, instrumentation is also necessary for unforeseen situations (that is, to ensure that should BVPS-2 conditions evolve differently than predicted by the safety analyses, the main control room operating staff has sufficient information to evaluate and monitor the course of the event). Additional instrumentation is also needed to indicate to the operating staff whether the integrity of the in-core fuel clad, the RCS pressure boundary, or the reactor containment has degraded beyond the prescribed limits defined as a result of the BVPS-2 safety analyses and other evaluations.

The following five classifications of variables have been identified to provide this instrumentation:

1. Operator manual actions, identified in the operating procedures that are associated with DBA events, are preplanned. Those variables that provide information needed by the operator to perform these manual actions are designated Type A. The basis for selecting Type A variables is given in Section 7.5.2.2.1.

2. Those variables needed to assess that BVPS-2 critical safety functions are being accomplished or maintained, as identified in the BVPS-2 safety analyses and other evaluations, are designated Type B.

3. Variables used to monitor for the gross breach, or the potential for gross breach, of the in-core fuel clad, the RCS pressure boundary, or the reactor containment, are designated Type C. Variables used to monitor the potential breach of containment have an arbitrarily determined extended range. The extended range is chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analyses. The response characteristics of Type C information display channels will allow the main control room

staff to detect conditions indicative of gross failure of any of the three fission product barriers, or the potential for gross failure of these barriers. Although variables selected to fulfill Type C functions may rapidly approach the values that indicate an actual gross failure, it is the final steady-state value reached that is important. Therefore, a high degree of accuracy is not necessary for Type C information display channels.

4. Those variables needed to assess the operation of individual safety systems, and other systems important to safety, are designated Type D.

5. The variables that are required for use in determining the magnitude of the postulated releases, and continually assessing any such releases of radioactive materials, are designated Type E.

The five classifications of variables are not mutually exclusive, in that a given variable (or instrument) may be included in one or more types. When a variable is included in one or more of the five classifications, the equipment monitoring this variable is specified in accordance with the highest category identified.

Three categories of design and qualification criteria have been identified. The differentiation is made in order that a hierarchy of information is recognized in specifying accident monitoring instrumentation. Category 1 instrumentation has the highest performance requirements and should be utilized for information which cannot be lost under any circumstances. Category 2 and Category 3 instruments are of lesser importance in determining the state of BVPS-2 and do not require the same level of operational assurance.

The primary differences between category requirements are in qualification, single failure, power supply, and display requirements. Category 1 requires seismic and environmental qualification, the application of the single failure criterion, utilization of emergency power sources, and an immediately accessible display. Category 2 requires seismic and environmental qualification commensurate with the required function but does not require the single failure criterion, emergency power sources, or an immediately accessible display. Category 2 does require a rigorous performance verification for a single instrument channel. Category 3, which is high quality commercial grade equipment, does not require seismic or environmental qualification, single failure criterion, emergency power, or an immediately accessible display.

Table 7.5-1 summarizes the following information for each variable identified:

1. Instrument range/status,

2. Environmental qualification,

3. Seismic qualification,

4. Display methodology (number of channels and indicator device), and

5. Type/category.

7.5.2.1 Definitions

7.5.2.1.1 Design Basis Accident Events

Those events, any one of which could occur during the lifetime of a particular plant, and those events not expected to occur but postulated because their consequences would include the potential for release of significant amounts of radioactive gaseous, liquid, or particulate material to the environment, are DBA events. Excluded are those events (defined as normal and anticipated operational occurrences in 10 CFR 50) expected to occur more frequently than once during the lifetime of a particular plant. The limiting accidents that were used to determine instrument functions are:

1. Loss-of-coolant accident (LOCA),

2. Main steam line break (MSLB),

3. Feedwater line break, and

4. Steam generator tube rupture.

7.5.2.1.2 Safe Shutdown (Hot Standby)

The state of BVPS-2 in which the reactor is subcritical such that K_{eff} is less than or equal to 0.99 and the RCS temperature is greater than or equal to 350°F. Additional features are provided to reach and maintain a cold shutdown plant condition. These are discussed in Section 5.4.7.

7.5.2.1.3 Controlled Condition

The state of the plant that is achieved when the subsequent action portion of the BVPS-2 emergency operating procedures (EOP) is implemented and the critical safety functions are being accomplished or maintained by the main control room operating staff.

7.5.2.1.4 Critical Safety Functions

Those safety functions that are essential to prevent a direct and immediate threat to the health and safety of the public. These are the accomplishing or maintaining of:

1. Reactivity control,

2. Reactor coolant system pressure control,

3. Reactor coolant inventory control,

4. Reactor core cooling,

5. Heat sink maintenance, and

6. Reactor containment environment.

7.5.2.1.5 Immediately Accessible Information

Information that is visually available to the main control room operating staff immediately (that is, within human response time requirements) once they have made the decision that the information is needed.

7.5.2.1.6 Primary Information

Information that is essential for the direct accomplishment of the preplanned manual actions necessary to bring BVPS-2 into a safe condition in the event of a DBA event. It does not include those variables that are associated with contingency actions.

7.5.2.1.7 Contingency Actions

Those manual actions that address conditions beyond the DBA event.

7.5.2.1.8 Key Variables

Those variables which provide the most direct measure of the information required.

7.5.2.1.9 Backup Information

That information, made up of additional variables beyond those classified as key, that provide supplemental and/or confirmatory information to the main control room operating staff. Backup variables do not provide indications as reliable or complete as those provided by primary variables, and are not usually relied upon as the sole source of information.

7.5.2.1.10 Categories 1, 2, and 3

References to Categories 1, 2, and 3 are as stated in Regulatory Guide 1.97 Category Classifications.

7.5.2.2 Variable Types

The accident monitoring variables and information display channels are those required to enable the main control room operating staff to perform the functions defined by Type A, B, C, D, and E classifications as follows.

7.5.2.2.1 Type A

Those variables that provide the primary information required to permit the main control room operating staff to:

1. Perform the diagnosis specified in the BVPS-2 EOPs,

2. Take the specified preplanned manually controlled actions, for which no automatic control is provided and that are required for safety-related systems to accomplish their safety function, in order to recover from the DBA event, and

3. Reach and maintain a safe shutdown (hot standby) condition.

The verification of the actuation of safety-related systems has been excluded from the Type A definition. The variables which provide this verification are included in the definition of Type D.

Variables in Type A are restricted to preplanned actions for DBA events. Contingency actions and additional variables which might be utilized will be in Types B, C, D, and E.

7.5.2.2.2 Type B

Those variables that provide the main control room operating staff with information to assess the process of accomplishing or maintaining critical safety functions, that is, reactivity control, RCS pressure control, RCS inventory control, reactor core cooling, heat sink maintenance, and reactor containment environment.

7.5.2.2.3 Type C

Those variables that provide the main control room operating staff the information to monitor:

1. The extent to which variables that indicate the potential for causing a gross breach of a fission product barrier have exceeded the design basis values, and

2. That the in-core fuel clad, the RCS pressure boundary, or the reactor containment may have been subjected to gross breach.

These variables include those required to initiate the early phases of the emergency plan. Excluded are those associated with monitoring radiological release from BVPS-2, which are included in Type E.

Type C variables used to monitor the potential for breach of a fission product barrier have an arbitrarily determined extended range. The extended range was chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analysis.

7.5.2.2.4 Type D

Those variables that provide the main control room operating staff with sufficient information to monitor the performance of:

1. Plant safety systems employed for mitigating the consequences of an accident and subsequent BVPS-2 recovery to attain a safe shutdown condition. These include verification of the automatic actuation of safety-related systems, and

2. Other systems normally employed for attaining a safe shutdown (hot standby) condition.

7.5.2.2.5 Type E

Those variables that provide the main control room operating staff with information to:

1 Monitor the habitability of the main control room,

2. Estimate the mamitude of release of radioactive material through identified pathways and continually assess such releases, and

3. Monitor and estimate radiation levels and radioactivity in the environment surrounding BVPS-2.

7.5.2.3 Variable Categories

The qualification requirements of the Type A, B, C, D, and E accident monitoring instrumentation are subdivided into three categories. Descriptions of the three categories are given in the following. Table 7.5-2 briefly summarizes the selection criteria for Type A, B, C, D, and E variables in each of the three categories. Table 7.5-3 briefly summarizes the design, qualification, and interface requirements of these three designated categories.

7.5.2.3.1 Category 1

7.5.2.3.1.1 Selection Criteria for Category 1

The selection criteria for Category 1 variables have been subdivided according to the variable type. For Type A, those key variables used for diagnosis or providing information for necessary operator action have been designated Category 1. For Type B, those key variables which are used for monitoring the process of accomplishing or maintaining critical safety functions have been designated Category 1. For Type C, those key variables which are used for monitoring the potential for breach of a fission product barrier have been designated Category 1. There are no Type D or Type E Category 1 variables.

7.5.2.3.1.2 Qualification Criteria for Category 1

The instrumentation is environmentally and seismically qualified in accordance with Sections 3.11 and 3.10, respectively. Instrumentation shall continue to read within the required accuracy following, but not necessarily during, a seismic event. At least one instrumentation channel is qualified from a sensor up to and including a display. For the balance of the instrumentation channels, qualification applies up to and includes the channel isolation device (Refer to Section 7.5.2.3.4 with regard to extended range instrumentation qualification).

7.5.2.3.1.3 Design Criteria for Category 1

1. No single failure within either the accident monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with the failures that are a condition of or result from a specific accident, will prevent the main control room operating staff from being presented the required information. Where failure of one accident monitoring channel results in information ambiguity (for example, the redundant displays disagree), additional information is provided to allow the control room operating staff to analyze the actual conditions in the plant. This may be accomplished by providing additional independent channels of information of

the same variable (addition of an identical channel), or by providing independent channels which monitor different variables that bear known relationships to the multiple channels (addition of a diverse channel(s)). Redundant or diverse channels are electrically independent and physically separated from each other, to the extent practicable with two train separation, and from equipment not classified important to safety in accordance with the position stated in Section 1.8 for Regulatory Guide 1.75.

For situations such as isolation valves in series, the intent is generally to verify the isolation function. In such a situation a single indication on each valve is sufficient to satisfy the single failure criterion if those indications are from different trains (that is, unambiguous indication of isolation). If ambiguity does not result from failure of the channel, then a third redundant or diverse channel is not required.

2. The instrumentation is energized from station emergency power sources and battery-backed where momentary interruption is not tolerable, as discussed in Regulatory Guide 1.32.

3. The out-of-service interval is based on normal Technical Specification requirements for the system it serves where applicable, or where specified by other requirements.

4. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. Those instruments, for which the required interval between testing is less than the normal time interval between BVPS-2 shutdowns, are provided with a capability for testing during power operation.

5. Whenever means for removing channels from service are included in the design, the design provides administrative control of the access to such removal means.

6. The design provides administrative control of the access to all set point adjustments, module calibration adjustments, and test points.

7. The monitoring instrumentation design minimizes the development of conditions that would cause meters, annunciators, recorders, alarms, etc., to give anomalous indications that could be potentially confusing to the main control room operating staff.

8. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

9. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

10. Periodic checking, testing, calibration, and calibration verification is done in accordance with the applicable portions of Regulatory Guide 1.118.

11. The range selected for the instrumentation encompasses the expected operating range of the variable being monitored, to the extent that saturation does not negate the required action of the instrument, in accordance with the applicable portions of Regulatory Guide 1.105.

7.5.2.3.1.4 Information Processing and Display Interface Criteria for Category 1

The interface criteria specified here provide requirements to be implemented in the processing and displaying of the information.

1. The main control room operating staff have immediate access to the information from redundant or diverse channels in units of measure familiar to them (that is, for temperature reading, degrees are used, not volts). Where two or more instruments are needed to cover a particular range, overlapping instrument spans are provided.

2. A historical record of at least one instrumentation channel for each process variable is maintained. A recorded pre-event history for these channels is required for a minimum of 1 hour, and continuous recording of these channels is required following an accident until such time as continuous recording of such information is no longer deemed necessary. This recording is to be available when required and does not need to be immediately accessible.

   The time period of 1 hour was selected based on a representatively slow transient which is bounded by this time requirement. A 1/2 inch equivalent break area LOCA was selected since the trip occurs at approximately 50 minutes after initiation. Where direct and immediate trend or transient information is essential for operator information or action, the recording is immediately accessible.

7.5.2.3.2 Category 2

7.5.2.3.2.1 Selection Criteria for Category 2

The selection criteria for Category 2 variables are subdivided according to the variable type. For Types A, B, and C, those variables which provide preferred backup information are designated Category 2. For Type D, those key variables used for monitoring the performance of safety systems have been designated Category 2. For Type E, those key parameters to be monitored for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases have been designated Category 2.

7.5.2.3.2.2 Qualification Criteria for Category 2

Category 2 instrumentation is qualified from the sensor up to and including the isolation device for at least the environment in which it must operate to perform its intended function. Instrumentation associated with those safety-related systems that are required to operate following a safe shutdown earthquake (SSE), to mitigate a consequential plant incident, shall be seismically qualified. Environmental qualification will meet, or exceed the requirements of IEEE Standard 323-1971, 1974, and NUREG-0588, Revision 1 (USNRC 1981), which interprets BVPS-2 as being a Category II type plant. Seismic qualification is conducted in accordance with IEEE Standard 344-1971, 1975, if this instrumentation is part of a safety-related system.

7.5.2.3.2.3 Design Criteria for Category 2

1. The instrumentation is energized from a highly reliable on-site power source, not necessarily the emergency power source, which is battery-backed where momentary interruption is not tolerable.

2. The out-of-service interval is based on normal Technical Specification requirements for the system it serves where applicable, or where specified by other requirements.

3. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between BVPS-2 shutdowns, a capability for testing during power operation is provided.

4. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

5. The design facilitates administrative control of the access to all setpoint adjustments, module calibration adjustments, and test points.

6. The monitoring instrumentation design minimizes the potential for the development of conditions that would cause meters, annunciators, recorders, and alarms, etc., to give anomalous indications that could be potentially confusing to the operator.

7. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

8. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

9. Periodic checking, testing, calibration, and calibration verification is in accordance with applicable portions of Regulatory Guide 1.118.

10. The range selected for the instrumentation encompasses the expected operating range of the variable being monitored, to the extent that saturation does not negate the required action of the instrument, in accordance with the applicable portions of Regulatory Guide 1.105.

7.5.2.3.2.4 Information Processing and Display Interface Criteria for Category 2.

The instrumentation signal is, as a minimum, processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.3.3 Category 3

7.5.2.3.3.1 Selection Criteria for Category 3

The selection criteria for Category 3 variables have been subdivided according to the variable type. For Types A, B, and C, variables which can provide backup information are usually designated Category 3, unless they are primary backup variables, in which case they would be classified as Category 2. For Types D and E, those variables which provide preferred backup information have been designated Category 3.

7.5.2.3.3.2 Qualification Criteria for Category 3

The instrumentation is high quality commercial grade that is not required to provide information when exposed to a post-accident adverse environment. Only normal and abnormal environments are applicable.

7.5.2.3.3.3 Design Criteria for Category 3

1. Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal interval between BVPS-2 shutdowns, a capability for testing during power operation is provided.

2. Whenever means for removing channels from service are included in the design, the design facilitates administrative control of the access to such removal means.

3. The design facilitates administrative control of the access to all set point adjustments, module calibration adjustments, and test points.

4. The monitoring instrumentation design minimizes the potential for the development of conditions that would cause meters, annunciators, recorders, and alarms, etc, to give anomalous indications that could be potentially confusing to the operator.

5. The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

6. To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

7.5.2.3.3.4 Information Processing and Display Interface Criteria for Category 3

The instrumentation signal is, as a minimum, processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.3.4 Extended Range Instrumentation Qualification Criteria

The qualification environment for extended range instrumentation is based on the DBA events, except the assumed maximum value of the monitored variable shall be the value equal to the specified maximum range for the variable. The monitored variable is assumed to approach this peak by extrapolating the most severe initial ramp associated with the DBA events. The decay for this variable is considered proportional to the decay for the variable associated with the DBA events. No additional qualification margin needs to be added to the extended range variable. All environmental envelopes, except that pertaining to the variable measured by the information display channel, are those associated with the DBA events. The environmental qualification requirement for extended range equipment does not account for steady-state elevated levels that may occur in other environmental parameters associated with the extended range variable. For example, a sensor measuring containment pressure must be qualified for the measured process variable range (that is, three times design pressure for concrete containments), but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for DBA events analyzed in Chapter 15. The extended range requirement is to ensure that the equipment will continue to provide information if conditions degrade beyond those postulated in the safety analysis. Since extended variable ranges are non-mechanistically determined, extension of associated parameter levels is not justifiable and is therefore not required.

7.5.3 Description of Variables

7.5.3.1 Type A Variables

Type A variables are defined in Section 7.5.2.2.1. They are the variables which provide primary information required to permit the main control room operating staff to:

1. Perform the diagnosis specified in the BVPS-2 EOPs,

2. Take specified preplanned manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety function to recover from a DBA event (verification of actuation of safety systems is excluded from Type A and is included as Type D), and

3. Reach and maintain a safe shutdown (hot standby) condition.

Key Type A variables have been designated Category 1. These are the variables which provide the most direct measure of the information required. The key Type A variables are:

1. Reactor coolant system pressure (wide range),
2. Reactor coolant hot leg temperature (T_{hot}) (wide range),
3. Reactor coolant cold leg temperature (T_{cold}) (wide range),
4 Steam generator level (wide range),
5. Steam generator level (narrow range),
6. Pressurizer level,
7. Reactor containment pressure,
8. Steamline pressure,
9. Reactor containment water level (wide range),
10. Reactor containment water level (narrow range),
11. Primary plant demineralized water storage tank level,
12. Auxiliary feedwater flow,
13. Reactor containment area radiation level,
14. Core exit temperature, and
15. Secondary system radiation - main steamline radiation.

Preferred backup Type A variables have been designated Category 2. RCS subcooling is designated as Type A, Category 2. The BVPS-2 recognizes that the degree of subcooling can be obtained from system pressure and temperature using Type A, Category 1 variables and a steam table. However, it is also recognized that the main control room staff will also have access to their subcooling monitor (required by the U.S. Nuclear Regulatory Commission (USNRC) NUREG-0737, Action Item 11.F.2). Therefore, RCS subcooling is considered a backup Type A variable which, in turn, requires Category 2 qualification.

No Type A variable has been designated Category 3. A summary of the Type A variables is provided in table 7.5-4.

7.5.3.2 Type B Variables

Type B variables are defined in Section 7.5.2.2.2. They are the variables that provide information to the main control room operating staff to assess the process of accomplishing or maintaining critical safety functions, that is:

1. Reactivity control,

2. Reactor coolant system pressure control,

3. Reactor coolant inventory control,

4. Reactor core cooling,

5. Heat sink maintenance, and

6. Reactor containment environment.

Variables which provide the most direct indication (that is, key variables) to assess each of the six critical safety functions have been designated Category 1. Preferred backup variables have been designated Category 2. All other backup variables are Category 3. The Type B variables are listed in Table 7.5-5.

7.5.3.3 Type C Variables

Type C variables are defined in Section 7.5.2.2.3. Basically, they are the variables that provide the main control room operating staff with information to monitor the potential for breach or actual gross breach of:

1. In-core fuel clad,

2. Reactor coolant system boundary, and

3. Containment boundary.

(Variables associated with monitoring of radiological release from BVPS-2 are included in Type E).

Those Type C key variables which provide the most direct measure of the potential for breach of one of the three fission product boundaries have been designated Category 1. Backup information indicating potential for breach is designated Category 2. Variables which indicate actual breach have been designated as preferred backup information and are qualified to Category 2.

Table 7.5-6 summarizes the selection of Type C variables.

7.5.3.4 Type D Variables

Type D variables are defined in Section 7.5.2.2.4. They are those variables that provide sufficient information to the main control room operating staff to monitor the performance of:

1. Plant safety systems employed for mitigating the consequences of an accident and subsequent BVPS-2 recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety systems, and

2. Other systems normally employed for attaining a safe shutdown condition.

Type D key variables are designated Category 2. Preferred backup information is designated Type D, Category 3.

The following systems or major components have been identified as requiring Type D information to be monitored:

1. Pressurizer level and pressure control (assess status of RCS following return to normal pressure and level control under certain post-accident conditions),

2. Chemical and volume control system (employed for attaining safe shutdown under certain post-accident conditions),

3. Secondary pressure and level control (employed for restoring/maintaining a secondary heat sink under post-accident conditions),

4. Emergency core cooling system,

5. Auxiliary feedwater system,

6. Containment systems,

7. Component cooling water system,

8. Service water system,

9. Residual heat removal system,

10. Heating, ventilation, and air-conditioning systems (if required for engineered safety features operation),

11. Electric power to vital safety systems, and

12. Verification of automatic actuation of safety systems.

Table 7.5-7 lists the key Type D variables identified for each system listed above.

For the purpose of specifying seimsic qualification for Type D, Category 2 variables, it is assumed that a seismic event and a break in Category 1 piping will not occur concurrently. As a result, the limiting event is unisolated (single failure of a main steamline isolation valve) break in Class 2 main steam piping. Instrumentation associated with the safety systems which are required to mitigate, and the instrumentation necessary to monitor, this event should be seismically qualified. Similarly, the environmental qualification of Type D, Category 2 variables depends on whether the instrumentation is subject to a high energy line break (HELB) when required to provide information.

7.5.3.5 Type E Variables

Type E variables are defined in Section 7.5.2.2.5. They are those variables that provide the main control room operating staff with information to:

1. Monitor the habitability of the main control room,

2. Estimate the magnitude of release of radioactive materials through identified pathways, and

3. Monitor and estimate radiation levels and radioactivity in the environment surrounding BVPS-2.

Key Type E variables are qualified to Category 2 requirements. Preferred backup Type E variables are qualified to Category 3 requirements.

Table 7.5-8 lists the key Type E variables.

7.5.4 Additional Information

A cross-reference of the variable and category for each instrument identified in the BVPS-2 survey is included in Table 7.5-9.

Table 7.5-1 identifies the instruments utilized at BVPS-2 which address the recommendations of both NUREG-0737 (USNRC 1980) and Regulatory Guide 1.97. The instruments identified meet the intent of the guidance provided in NUREG-0737.

7.5.5 Bypass and Inoperable Status Indication

This plant computer-based system is utilized in conjunction with the main annunciator system to provide indication of the bypass or inoperability of each redundant portion of a system that performs a safety-related function. Bypass indication may be applied administratively or automatically. The systems which are covered by Table 7.5-10 are designed in accordance with the guidelines of Regulatory Guide 1.47. Specific inputs are shown on Figures 7.5-1, 7.5-2, 7.5-3, 7.5-4, 7.5-5, 7.5-6, 7.5-7, 7.5-8, 7.5-9, 7.5-10, 7.5-11, 7.5-12, 7.5-13, 7.5-14, 7.5-15, 7.5-16, 7.5-17, 7.5-18, 7.5-19, 7.5-20, 7.5-21, 7.5-22, 7.5-23, 7.5-24, 7.5-25, 7.5-26, 7.5-27, 7.5-28, 7.5-29, 7.5-30, 7.5-31, 7.5-32, 7.5-33 and 7.5-34.

Compliance with Regulatory Guide 1.47 for bypassed and inoperable status design philosophy is described below:

1. A bypass indicator is provided for each protection system. "Bypass" includes any deliberate action which renders a protection system inoperable.

2. The indicator is at the system level with a separate indicator for each train.

3. The indicator is operated automatically only by actions which meet all these criteria:

   a. The action is deliberate. (Component failure may be indicated by component failure indicators but should not operate the system bypass indicator. It is not the intent of the indicator to show operator errors or component failures.)

b. The action is expected to occur more often than once a year. This "more often than once a year" criterion is interpreted liberally. If an accessible, permanently installed electrical control device will bypass a safety system, it is assumed that the device will be used more than once a year. Also, manual valves or nonremotely controlled devices within the containment are not accessible.

c. The action is expected when the protection system must be operable. (Bypass of source range flux trip during normal power operation would not, for example, be indicated on the system bypass indicator. It may be indicated on a channel or component status indicator.)

d. The action renders the system inoperable, not merely potentially inoperable. (If, for example, redundant, parallel, 100-percent valves are provided for the discharge line of a spray pump, the system bypass indicator would not be actuated by the closing of only one of those valves. Valve closing may be indicated on a component status indicator.

e. Some deliberate action has taken place in the protection system or a necessary supporting system. (For example, if the cooling water inlet valve for a recirculation spray heat exchanger is deliberately closed, the system bypass indicator for the recirculation spray system would be operated.)

4. The bypass indicators are separate from other plant indicators and grouped in a logical fashion.

5. A capability is provided to operate each bypass indicator manually. This lets the operator provide bypass indication for an event that renders a safety system inoperable but does not automatically operate the system bypass indicator.

6. There is not any capability to defeat an automatic operation of a bypass indicator. (Audible alarms may be silenced.)

7. The bypass indicators are accompanied by audible alarm.

8. The indication system is mechanically and electrically isolated from the safety system to avoid degradation of the safety system. No fault in the indicator system can impair the ability of the safety system to perform its safety-related function. The bypass indicators are not considered safety-related; i.e., they need not be designed to safety system criteria such as IEEE Standard 279-1971.

9. In accordance with IEEE Standard 279-1971, Paragraph 4.20, the operator must be able to determine why a system level bypass is indicated. This information is provided by the plant computer.

10. Service water system inoperative and diesel generator inoperative indicators are provided. These support systems are unique and important enough to warrant bypass indicators.

11. The system design meets the recommendations of ICSB-21 as follows:

    a. Each safety system has a Train A (orange) and Train B (purple) bypass indicator. The indicators are grouped together by train on the main control board. Support systems have white bypass indicators and are arranged together with the associated train of bypass indicators. Safety system indicators are lit whenever any support subsystem is inoperable as described in No. 3 above.

    b. Means by which the operator can cancel erroneous bypassed indicators are not provided.

    c. The bypass indication system does not perform functions essential to safety. No operator action is required based solely on the bypass indication.

    d. The indication system has no effect on plant safety systems.

    e. The bypass indicating and annunciating function can be tested during normal plant operation.

7.5.6 Safety Parameter Display System

The BVPS-2 design incorporates a Safety Parameter Display System (SPDS), as required by NUREG-0737, Action Item I.D.2 (USNRC 1980). Liquid Crystal Diode (LCD) displays are installed in the Main Control Room, the Technical Support Center, and in the Emergency Response Facility.

The Safety Parameter Display System is included in the BVPS-2 plant computer system. The BVPS-2 plant computer system is configured with redundant central processor units for increased reliability and availability.

The SPDS is designed to display the status of the following six critical safety functions (CSFs) to the operators.

1. Sub-criticality Status - for loss-of-subcriticality, loss-of-core shutdown

2. Core Cooling Status - for inadequate core cooling, degraded core cooling, saturated core cooling

3. Heat Sink Status - for loss-of-secondary heat sink, steam generator overpressure, steam generator high level, loss-of-normal steam release capabilities

4. Vessel Integrity Status - for imminent pressurized thermal shock, anticipated pressurized thermal shock

5. Containment Integrity Status - for high containment pressure, containment flooding, high containment radiation level

6. Inventory Status - for high pressurizer level, low pressurizer level, voids in reactor vessel.

Dynamic color-coded status blocks representing the six CSFs are located on every user display. Design of the displays incorporates accepted human factors engineering principles so the displayed information can be readily perceived and comprehended by the SPDS users.

The system is designed to ensure that sufficient isolation exists to preclude propagation of system faults and subsequent degradation to safety systems from which the SPDS input signals originate. For a more complete discussion of isolation methods, refer to FSAR Section 8.3.

The design of the SPDS has been subjected to a verification and validation (V&V) program to confirm that the design is sufficient to provide reasonable assurance that a continuous display of valid and reliable information is available from which the plant safety status can be addressed.

7.5.7 References for Section 7.5

U.S. Nuclear Regulatory Commission (USNRC) 1980. Clarification of TMI Action Plan Requirements. NUREG-0737.

USNRC 1981. Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment; Resolution of Generic Technical Activity A-24. NUREG-0588, Revision 1.

Tables for Section 7.5

TABLE 7.5-1

SAFETY RELATED DISPLAY INSTRUMENTATION (SEE NOTES 1,2,3)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
RCS pressure (WR)	0-3,000 psig	A1, B1, C1, B2, C2, D2	Yes	Yes	3 per plant	2 meters 1 channel on PSMS display 1 recorder	fuel load	1E	Yes
RCS T_{hot} (WR)	0-700°F	A1, B2	Yes	Yes	1 per loop	3 meters 3 recorders	fuel load	1E	Yes
RCS T_{cold} (WR)	0-700°F	A1, B2	Yes	Yes	1 per loop	3 meters 3 recorders	fuel load	1E	Yes
Steam generator level (WR)	0-100% of span	A1, B1, B2, D2	Yes	Yes	1 per steam generator	3 meters 3 recorders	complete	1E	Yes
Steam generator level (NR)	0-100% of span	A1, B1, D2	Yes	Yes	3 per steam generator	9 meters 3 recorders	fuel load	1E	Yes
Pressurizer level	0-100% of span	A1, B1, D2	Yes	Yes	3 per plant	3 meters 3 recorders	complete	1E	Yes
Containment pressure	-5 to 55 psig	A1, B1, B2, C2, D2	Yes	Yes	4 per plant	4 meters 2 recorders	complete	1E	Yes
Steamline pressure	0 to 1,200 psig	A1, B1, D2	Yes(14)	Yes	3 per loop	9 meters 3 recorders	complete	1E	Yes
Containment water level (WR)	0-225 in	A1, B1, B2, C2, D2	Yes	Yes	2 per plant	2 meters 1 recorder	complete	1E	Yes
Containment water level (NR)	0-12 in	A1, B1, B2, C2, D2	Yes	Yes	2 per plant	2 meters 1 recorder	fuel load	1E	Yes
Refueling water storage tank level	0-730 in	D2	Yes	Yes	2 per plant	2 meters 1 recorder	complete	1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
Primary Plant DWST level	0-330 in	A1, D2	Yes	Yes	3 per plant	2 meters 1 channel on PSMS display 1 recorder	fuel load	1E	Yes
Auxiliary feedwater flow	0-400 gpm	A1, B1, D2	Yes	Yes	2 per loop	6 meters 3 recorders	fuel load	1E	Yes
Core exit temperature	100-2200°F	A1, B1, C1	Yes	Yes	51	All channels on PSMS display; 1 channel on meter and recorder	fuel load	1E	Yes
Containment area radiation level (high range)	10^{0}-10^{7} R/Hr	A1, B1, B2, E2	Yes(15)	Yes	2 per plant	2 meters	fuel load	1E	Yes
Secondary system radiation	10^{-2}-10^{3} μCi/CC	A1, B2, E2	Yes	Yes	1 per loop	1 meter	fuel load	1E	Yes
RCS Subcooling	200°F subcooling to 35° F super-heated	A2, B2	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on meter and recorder	fuel load	1E	Yes
Control rod position	In/Out	B3	No	No	1/rod	1 status light/rod	complete	non-1E	Yes
Neutron flux Lower range	1 to 10^{6} CPS	B1	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on recorder	fuel load	1E	Yes
Upper range	10^{-4} - 200% of power	B1	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on recorder	fuel load	1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
Reactor vessel level Instrumentation system									
Full range	0-120% level	B2, C2	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on recorder	fuel load	1E	No(5)
Upper range	60-120% level	B2, C2	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on recorder	fuel load	1E	No(5)
Dynamic head	0-120% liquid	B2, C2	Yes	Yes	2 per plant	2 channels on PSMS display; 1 channel on recorder	fuel load	1E	No(5)
Containment hydrogen concentration	0-10%	B1, C1	Yes	Yes	2 per plant	2 channels on PSMS display 1 channel on recorder	fuel load	1E	Yes
Plant vent radiation level	10^{-7}-10^{5} μci/cc	C2, E2	Yes	Yes	1 per plant	1 meter	fuel load	1E	Yes
Containment isolation valves status	Open/Closed	C2, D2	Yes(12)	Yes(12)	1 per valve	1 pair lights per valve	complete	1E(12)	Yes
Containment pressure (extended range)	0-180 psia	C1, C2	Yes	Yes	2 per plant	2 channels on PSMS display 1 channel on recorder	complete	1E	Yes
Primary coolant activity	1μci/ml to 10 ci/ml	C3	No	No	N/A	Analysis	complete	non-1E	Yes
Site environmental radiation level	**	C3, E3	No	No	N/A	Portable	complete	non-1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
Pressurizer heater power availability	0-2400 kW	D2	No	No	1 per plant	computer	complete	non-1E	Yes(6)
PORV status	Open/Closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Charging system flow	0-150 gpm	D2	Yes	Yes	1 per plant	1 meter	complete	non-1E	Yes
Primary safety valve status	Open/Closed	D2	Yes	Yes	1 per valve	plasma display	fuel load	1E	Yes
Letdown flow	0-200 gpm	D2	Yes	Yes	1 per plant	1 meter	complete	non-1E	Yes
Volume control tank level	0-100% of span	D2	Yes	Yes	1 per plant	1 meter	complete	non-1E	Yes
CVCS valve status	Open/Closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Decay heat removal valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Main steamline isolation valve status	Open/closed	B2, D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Main steamline isolation valve valve	Open/closed	B2, D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
S/G safety valve status	Open/closed	D2	Yes	Yes	1 per valve	PSMS display	fuel load	1E	Yes
RCP seal injection flow	0-15 gpm	D2	Yes	Yes	1 per pump	3 meters	complete	non-1E	Yes
S/G atmospheric steam dump valve	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Main feedwater control valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Main feedwater control bypass valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Main feedwater isolation valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
Main feedwater flow	0-5 MPPH	D2	Yes	Yes	2 per S/G	6 meters	complete	1E	Yes
S/G blowdown isolation valves status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
HHSI flow	0-1,000 gpm	D2	Yes	Yes	1 per train	2 meters	complete	1E	Yes
LHSI flow	0-5,000 gpm	D2	Yes	Yes	1 per train	2 meters	complete	non-1E	Yes
ECCS valve status	Open/Closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Auxiliary feedwater valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Containment spray flow	0-4,000 gpm	D2	Yes	Yes	1 per pump	4 meters	complete	1E	Yes
Containment spray system valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
CCW header pressure	0-150 psig	D2	Yes	Yes	1 per header	3 channels on PSMS display	complete	1E	Yes
CCW header temperature	0-200°F	D2	Yes	Yes	1 per header	3 channels on PSMS display	complete	1E	Yes
CCW surge tank level	0-70 in	D2	Yes	Yes	1 per tank	2 meters	complete	1E	Yes
CCW flow	0-8,000 gpm	D2	Yes	Yes	1 per header	2 meters	complete	1E	Yes
CCW valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Service water system valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Service water system pressure	0-150 psig	D2	Yes	Yes	1 per train	2 meters	complete	1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
HVAC	Open/closed	D2	Yes	Yes	1 per damper	1 pair lights per damper	complete	1E	Yes
Ac/dc, vital instrument voltage	Bus specific	D2	Yes	Yes	1 per bus	1 per bus	complete	1E	Yes
RHR heat exchanger discharge temperature	50-400°F	D2	Yes	Yes	1 per heat exchanger	2 meters	complete	non-1E	Yes
RHR flow	0-5,000 gpm	D2	Yes	Yes	1 per train	2 meters	complete	1E	Yes
RHR valve status	Open/closed	D2	Yes	Yes	1 per valve	1 pair lights per valve	complete	1E	Yes
Reactor trip breaker position	Close-trip	D2	Yes	Yes	1 per breaker	Computer	complete	1E	Yes
Turbine stop valve position	0-100%	D2	No	No	1 per valve	4 meters	complete	non-1E	Yes
Turbine throttle valve position	0-100%	D2	No	No	1 per valve	4 meters	complete	non-1E	Yes
Motor driven auxiliary feedwater pump status	Run-trip	D2	Yes	Yes	1 per pump	1 pair lights per pump	complete	1E	Yes
Turbine driven auxiliary feedwater water pump status	Open/closed	D2	Yes	Yes	1 per steam admission valve	1 pair of lights per valve	complete	1E	Yes
Safety injection pump status	Run-trip	D2	Yes	Yes	1 per pump	1 pair lights per pump	complete	1E	Yes
Service water pump status	Run-trip	D2	Yes	Yes	1 per pump	1 pair lights per pump	complete	1E	yes
CCW pump status	Run-trip	D2	Yes	Yes	1 per pump	1 pair lights per pump	complete	1E	Yes

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
Control room radiation	10^{-2}-10^{3} mr/hr	E2	Yes	Yes	2 per plant	2 meters	fuel load	1E	Yes
Service water to recirculation heat exchanger concentration from liquid pathways	10^{-4}-10^{1} μci/cc	E2	Yes	Yes	1 per pathway	1 per pathway	fuel load	1E	Yes
Plant vent air flow rate	0 to 75,000 SFCM	E2	Yes	Yes	2	2 meters	complete	1E	Yes
Meteorlogical parameters	parameter specific	E3	No	No	1	strip chart recorder	fuel load	non-1E	No(7)
Condenser air ejector radiation									
Air ejector discharge	10^{-6}-10^{-1} μci/cc	E3	No	No	one per vent	one per vent	fuel load	non-1E	Yes
Air ejector delay bed exhaust	10^{-6}-10^{-1} μci/cc	E3	No	No	one per vent	one per vent	fuel load	non-1E	Yes
SI accumulator tank level									No(8)
SI tank pressure									No(8)
SI accumulator isolation valve status									Yes(8)
Boric acid charging flow									No(9)

TABLE 7.5-1 (Cont)

Variable	Range/Status	Type/Category(16)	Qualification Environmental	Qualification Seismic	Number of Channels	Indicator Device	Implementation Date (13)	Power Supply	Conformance
RCS soluble boron concentration	50-6000 ppm	B3	No	No	1	1 per channel	fuel load	non-1E	Yes
Analysis of primary coolant (gamma spectrum)	Isotopic analysis	E3	N/A	N/A	1	analysis	fuel load	non-1E	Yes
Primary coolant and sump sample	parameter specific	E3	No	No	1	1 per channel	fuel load	non-1E	Yes
Containment air sample	parameter specific	E3	No	No	1	1 per channel	fuel load	non-1E	Yes
Containment atmosphere temperature									No(10)
Containment atmosphere temperature									No(11)

NOTES TO TABLE 7.5-1

1. Quality Assurance is in accordance with the BVPS-2 program defined in FSAR Chapter 17.

2. Deleted

3. The BVPS-2 Design Basis only identified the key variables that are used for monitoring the performance of safety systems and other systems normally employed for attaining a safe shutdown condition. In accordance with the definitions in the Design Basis, these variables are designated Type D, Category 2. The preferred backup variables to the Type D variables are not specified in this document. Since these variables are designated Type D, Category 3, the instrumentation is only required to be high quality commercial grade without any post-accident environmental qualification. A decision was made not to specifically identify the potential long list of instrumentation available at BVPS-2 that meets this definition. Indeed, if the list was generated, it would be much more inclusive than the variables identified in Reg. Guide 1.97, Revision 2.

4. Deleted

5. BVPS-2 is installing the Westinghouse differential pressure Reactor Vessel Level Instrumentation System (RVLIS). This is an acceptable system for measuring coolant level in the reactor according to Generic Letter 83-28. BVPS-2 uses Core Exit Temperature and RCS Subcooling to support operation according to the Westinghouse Owners Group Emergency Response Guidelines. These guidelines require that the RVLIS meets Regulatory Guide 1.97 Category 2 criteria only. Operator verification of flows during safety injection operation and stringent termination criteria preclude the need for RVLIS under design basis accidents.

6. Pressurizer Heater Status - Regulatory Guide 1.97, Rev. 2, specified that heater current was the preferred parameter for determining heater status. For BVPS-2 the total watt power consumption is displayed by computer readout to the operator. This is backed up by qualified heater breaker position.

7. The recommended ranges for this instrumentation are: Wind speed 0 to 67 and -9 to 18°F for estimation of atmospheric stability. The instrumentation to be installed will cover the following ranges: Wind speed 0 to 100 mph and estimation of atmospheric stability ΔT (150-35 ft) -8.0 to +20.0°F; (500-35 ft) -8.0°F to +20.0°F. The wind speed sensors are calibrated to 0 to 90 mph. The wind speed processors and data loggers are scaled 0 to 100 mph. The instrumentation for wind speed meets the guidance of Regulatory Guide 1.23. The vertical temperature ranges cover the range of lapse rates (change of temperature with height) guidance of Reg. Guide 1.23 required to estimate the atmospheric stability class.

NOTES TO TABLE 7.5-1

8. The licensing basis used in the BVPS-2 Regulatory Guide 1.97, Revision 2 Design Document was that a safe shutdown condition was a hot standby condition. Parameters necessary to monitor the status of the plant while proceeding to a cold shutdown condition are not included in the Design Document. The accumulator pressure, accumulator isolation valve status, and accumulator nitrogen vent valve status were identified as Category 2 only if the plant has committed to safety grade cold shutdown.

9. The Westinghouse Owner's Group Emergency Response Guidelines do not consider boric acid charging flow as a parameter to be used by operators during or following an accident. Under these conditions borated water is pumped from the large volume RWST into the RCS. BVPS-2 has designated RWST level, HHSI flow, LHSI flow, containment water level, and emergency core cooling system (ECCS) valve status for monitoring the performance of the ECCS since the ECCS does not normally take suction from the boric acid tank. If boration is used following an accident, qualified charging flow indication and RCS sampling are used to demonstrate that the RCS is being adequately borated.

10. The installed instrumentation is designed to Category 3 criteria and the measured temperature is from 0° to 200°F. The Westinghouse Owner's Group Emergency Response Guidelines do not require operator action based on containment temperature indication, but rather use containment pressure indication, therefore containment temperature is considered a Category 3 parameter, and the existing range is adequate for normal operation.

11. The Westinghouse Owner's Group Emergency Response Guidelines do not require operator action based on containment sump water temperature indication. At saturated condition, sump water temperature can be inferred form containment pressure. Containment spray system valve status and containment spray flow indications are used to demonstrate that the Emergency Core Cooling System is operating properly when taking suction from the containment sump.

12. Note that although these valves are classified as Category 2, the associated instrumentation meets the qualification requirements for Category 1 instrumentation as discussed in FSAR Section 7.5.2.3.1, with the exception of 2CHS*FCV160 and 2CHS*HCV142 (See Table 6.2-60). These valves are closed during normal operation and post-accident conditions, and are powered from non-Class 1E sources.

NOTES TO TABLE 7.5-1

13. Under Implementation Date, "complete" means that this instrumentation already exists in the current design. All instrumentation will be installed by fuel load unless otherwise noted.

14. The main steam pressure transmitters are environmentally qualified for all events with the exception of the arbitrary 1.0 ft^2 MSLB in the main steam valve house imposed by NRC-BTP-ASB 3-1. The resultant environment produced by the 1.0 ft^2 break exceeds the qualified temperature of the transmitters' instrument cable. Failure of the cable has no adverse effect on RPS or SLI signal generation as the cables perform these functions prior to exceeding their qualified temperature. For the purposes of monitoring heat removal during plant cooldown following this specific event alternative Class 1E-powered instrumentation is available in the form of steam generator level, auxiliary feedwater flow, and RCS temperature. These variables provide sufficient indication that the steam generators have been isolated, that level is being maintained, and that primary system heat removal is in progress.

15. The Hi Range Radiation Monitors are environmentally qualified for all events. However, at maximum postulated containment temperatures, accuracy within the lowest two decades (0-50 R/HR) of this monitor may exceed a factor of 2 (Reg. Guide 1.97 criterion). This is an acceptable condition since radiation levels within this range do not affect operator action and verification of actual radiation levels can be obtained using a qualified, backup radiation monitor located outside containment near the personnel hatch.

16. The Type and Category of the listed variables refer to the minimum required categorization, as described in the BVPS submittal to the NRC regarding the station position on RG 1.97. The actual installed devices may meet the qualification standards of a higher variable category (e.g., refer to Note 12).

WR = Wide range.
NR = narrow range.
* = Range/Status information for radiation is not final.
** = Sufficient to monitor anticipated rates (refer to Section 12.5.2.2.3).

TABLE 7.5-2

SUMMARY OF SELECTION CRITERIA FOR TYPE A,B,C,D, AND E VARIABLES

Type	Category 1	Category 2	Category 3
A	Key variables that are used for diagnosis or providing information necessary for operator action.	Variables which provide preferred backup information.	None.
B	Key variables that are used for monitoring the process of accomplishing or maintaining critical safety functions.	Variables which provide preferred backup information.	Variables which provide backup information.
C	Key variables that are used for monitoring the potential for breach of a fission product barrier.	Variables which provide preferred backup information.	Variables which provide backup information..
D	None.	Key variables which are used for monitoring the performance of BVPS-2 systems.	Variables which provide preferred backup information which are used for monitoring the performance of BVPS-2 systems.
E	None.	Key variables for use in monitoring the habitability of the main control room; estimating the magnitude of the release of radioactive material through identified pathways and continually assessing such releases; and monitoring and estimating radiation and radioactivity in the environment surrounding BVPS-2.	Variables to be monitored which provide preferred backup information for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases.

TABLE 7.5-3

SUMMARY OF DESIGN, QUALIFICATION, AND INTERFACE REQUIREMENTS

Qualification	Category 1	Category 2	Category 3
Environmental	Yes	As appropriate (Section 7.5.2.3.2.2)	No
Seismic	Yes	As appropriate (Section 7.5.2.3.2.2)	No
Design			
Single failure criterion	Yes	No	No
Power supply	Emergency diesel generator	Highly reliable on-site	As required (Section 7.5.2.3.3.3)
Channel-out-of-service	Technical Specifications	Technical Specifications	As required (Section 7.5.2.3.3.3)
Testability	Yes	Yes	As required (Section 7.5.2.3.3.3)
Interface			
Minimum indication	Immediately accessible	Demand	Demand
Recording	Yes	As required (Section 7.5.2.3.2.4)	As required (Section 7.5.2.3.3.4)

TABLE 7.5-4

SUMMARY OF TYPE A VARIABLES

Variable	Variable Function	Type/ Category
RCS pressure (WR)	Key	A1
RCS hot leg (T_{hot}) (WR)	Key	A1
RCS cold leg (T_{cold}) (WR)	Key	A1
Steam generator level (WR)	Key	A1
Steam generator level (NR)	Key	A1
Pressurizer level	Key	A1
Containment pressure	Key	A1
Steamline pressure	Key	A1
Containment water level (WR)	Key	A1
Containment water level (NR)	Key	A1
Primary plant DWST level	Key	A1
Auxiliary feedwater flow	Key	A1
Containment area radiation level (HR)	Key	A1
Core exit temperature	Key	A1
Secondary system radiation level	Key	A1
RCS subcooling	Backup (P)	A2

NOTES:

WR = Wide range.
NR = Narrow range.
HR = High range.
P = Preferred.

TABLE 7.5-5

SUMMARY OF TYPE B VARIABLES

Function Monitored	Variable	Variable Function	Type/ Category
Reactivity control	Neutron flux	Key	B1
	T_{hot} (WR)	Backup (P)	B2
	T_{cold} (WR)	Backup (P)	B2
	Control rod position	Backup	B3
Reactor coolant system pressure control	RCS pressure(WR)	Key	B1
	Containment pressure	Backup (P)	B2
	Containment area radiation level (high range)	Backup (P)	B2
	Secondary system radiation level	Backup (P)	B2
Reactor coolant inventory control	Pressurizer level	Key	B1
	Reactor vessel level instrumentation system	Backup (P)	B2
	Containment water level (NR)	Backup (P)	B2
	Containment water level (WR)	Backup (P)	B2
	Steam generator level (WR)	Backup (P)	B2
Reactor core cooling	Core exit temperature	Key	B1
	T_{hot} (WR)	Backup (P)	B2
	T_{cold} (WR)	Backup (P)	B2
	RCS pressure (WR)	Backup (P)	B2
	RCS subcooling	Backup (P)	B2
	Reactor vessel level Instrumentation system	Backup (P)	B2
Heat Sink maintenance	Steam generator level (NR)	Key	B1
	Steam generator level (WR)	Key	B1
	Auxiliary feedwater flow	Key	B1
	Core exit temperature	Key	B1
	Steamline pressure	Key	B1
	Main steamline isolation and bypass valve status	Backup(P)	B2

TABLE 7.5-5 (CONT'D)

Function Monitored	Variable	Variable Function	Type/ Category
Containment environment	Containment pressure	Key	B1
	Containment area radiation level (high range)	Key	B1
	Containment water level (NR)	Key	B1
	Containment water level (WR)	Key	B1
	Containment hydrogen concentration	Key	B1

NOTES:

WR = Wide range.
NR = Narrow range.
P = Preferred.

TABLE 7.5-6

SUMMARY OF TYPE C VARIABLES

Function Monitored	Variable	Condition	Variable Function	Type/ Category
In-core fuel clad	Core exit temperature	Potential for breach	Key	C1
	Reactor vessel level instrumentation system	Potential for breach	Backup (P)	C2
	Primary coolant activity	Actual breach	Backup	C3
RCS boundary	RCS pressure(WR)	Potential for breach	Key	C1
	RCS pressure (WR)	Actual breach	Backup (P)	C2
	Containment pressure	Actual breach	Backup (P)	C2
	Containment water level (NR)	Actual breach	Backup (P)	C2
	Containment water level (WR)	Actual breach	Backup (P)	C2
Containment boundary	Containment pressure (extended range)	Potential for breach	Key	C1
	Containment hydrogen concentration	Potential for breach	Key	C1
	Plant vent radiation level	Actual breach	Backup (P)	C2
	Containment isolation valve status	Actual breach	Backup (P)	C2
	Containment pressure (extended range)	Actual breach	Backup (P))	C2
	Site environmental radiation level	Actual breach	Backup	C3

NOTES:

WR = Wide range.
NR = Narrow range.
P = Preferred.

TABLE 7.5-7

SUMMARY OF TYPE D VARIABLES

System	Variable	Variable Function	Type/ Category
Pressurizer level and pressure control	PORV status	Key	D2
	Safety valve status	Key	D2
	Pressurizer level	Key	D2
	RCS pressure (WR)	Key	D2
	Pressurizer heater power availability	Key	D2
Chemical and volume control system	Charging system flow	Key	D2
	Letdown flow	Key	D2
	Volume control tank level	Key	D2
	Seal injection flow	Key	D2
	CVCS valve status	Key	D2
Secondary pressure and level control	S/G atmospheric steam dump valve status	Key	D2
	S/G safety valve status	Key	D2
	MSIV and bypass valve status	Key	D2
	S/G blowdown isolation valve status	Key	D2
	Steamline pressure	Key	D2
	Auxiliary feedwater flow	Key	D2
	S/G level (NR)	Key	D2
	S/G level (WR)	Key	D2
	Main feedwater control and bypass valve status	Key	D2
	Main feedwater isolation valve status	Key	D2
	Main feedwater flow	Key	D2
	Decay heat removal valve status	Key	D2
Emergency core cooling sytstem	RWST level	Key	D2
	HHSI and LHSI flow	Key	D2
	Containment water level (NR)	Key	D2
	Containment water level (WR)	Key	D2
	ECCS valve status	Key	D2

TABLE 7.5-7 (Cont)

System	Variable	Variable Function	Type/ Category
Auxiliary feed	Auxiliary feedwater flow	Key	D2
	Auxiliary feedwater valve status	Key	D2
	Primary Plant DWST level	Key	D2
Containment	Containment spray flow	Key	D2
	Containment water level (WR) and (NR)	Key	D2
	Containment spray system valve status	Key	D2
	Containment pressure	Key	D2
Component cooling water system	Header pressure	Key	D2
	Header temperature	Key	D2
	Surge tank level	Key	D2
	CCW flow	Key	D2
	Valve status	Key	D2
Service water system	Valve status	Key	D2
	System pressure	Key	D2
RHR system	Heat exchanger discharge temperature	Key	D2
	Flow	Key	D2
	Valve status	Key	D2
	RCS pressure (WR)	Key	D2
HVAC systems	Environment to ESF components	Key	D2
Electrical power	Ac/dc vital instrument voltage	Key	D2
Verification of automatic actuation of safety systems	Reactor trip breaker position	Key	D2
	Turbine stop valve position	Key	D2
	Turbine throttle valve position	Key	D2
	Motor-driven auxiliary feedwater pump status	Key	D2
	Turbine-driven auxiliary feedwater pump (steam admission valve status)	Key	D2

TABLE 7.5-7 (Cont)

System	Variable	Variable Function	Type/ Category
	Safety injection pump status	Key	D2
	Service water pump status	Key	D2
	CCW pump status	Key	D2
	Containment isolation valve status	Key	D2

NOTES:

WR = Wide range.
NR = Narrow range.

TABLE 7.5-8

SUMMARY OF TYPE E VARIABLES

Variable	Variable Function	Type/ Category
Containment area radiation level (high range)	Key	E2
Plant vent radiation level	Key	E2
Secondary system - main steamline radiation level	Key	E2
Control room radiation level	Key	E2
Site environmental radiation level	Backup (P)	E3
Service water to recirculation heat exchanger - concentration from liquid pathways	Key	E2
Plant vent air flow rate	Key	E2
Air ejector discharge radiation level	Backup (P)	E3
Air ejector delay bed exhaust radiation level	Backup (P)	E3
Meteorological parameters	Backup (P)	E3

NOTE:

P = Preferred.

TABLE 7.5-9
Summary of Variables and Categories

Variable	Type A	Type B	Type C	Type D	Type E
	Type and Category				
RCS pressure (WR)	1	1,2	1,2	2	
T_{hot} (WR)	1	2			
T_{cold} (WR)	1	2			
S/G level (WR)	1	1,2		2	
S/G level (NR)	1	1		2	
Pressurizer level	1	1		2	
Containment pressure	1	1,2	2	2	
Steamline pressure	1	1		2	
RWST level				2	
Containment water level (WR and NR)	1	1,2	2	2	
Primary Plant DWST level	1			2	
Auxiliary feedwater flow	1	1		2	
Containment radiation level (High range)	1	1,2			2
Secondary system - main steamline radiation	1	2			2
Core exit temperature	1	1	1		
RCS subcooling	2	2			
Neutron flux		1			
Reactor vessel level instrumentation system		2	2		
Containment isolation valve status			2	2	
Control rod position		3			
Containment hydrogen concentration		1	1		
Containment pressure (extended range)			1,2		
Primary coolant activity			3		
Plant vent radiation level			2		2
Site environmental radiation level			3		3
PORV valve status				2	
Primary safety valve status				2	
Pressurizer heater power availability				2	
Charging system flow				2	
Letdown flow				2	
Volume control tank level				2	
CVCS valve status				2	

TABLE 7.5-9 (CONT'D)

Variable	Type and Category				
	Type A	Type B	Type C	Type D	Type E
RCP seal injection flow				2	
S/G atmospheric PORV status				2	
Main steamline isol valve status		2		2	
Main steamline bypass valve status		2		2	
S/G safety valve status				2	
Main feedwater control valve status				2	
Main feedwater control bypass valve status				2	
Main feedwater isolation valve status				2	
Main feedwater flow				2	
S/G blowdown isolation valve status				2	
Decay heat removal valve status				2	
HHSI flow				2	
LHSI flow				2	
ECCS valve status				2	
Auxiliary feedwater valve status				2	
Containment spray flow				2	
Containment spray systems valve status				2	
CCW header pressure				2	
CCW header temperature				2	
CCW surge tank level				2	
CCW flow				2	
CCW valve status				2	
Service water system pressure				2	
Service water system valve status				2	
RHR heat exchanger discharge temperature				2	
RHR flow				2	
RHR valve status				2	
ESF environment				2	
Ac/dc vital instrument voltage				2	

TABLE 7.5-9 (CONT'D)

Variable	Type A	Type B	Type C	Type D	Type E
Reactor trip breaker position				2	
Turbine stop valve position				2	
Turbine throttle valve position				2	
Motor-driven auxiliary feedwater pump status				2	
Turbine-driven auxiliary feedwater pump (steam admission valve status)				2	
Safety injection pump status				2	
Service water pump status				2	
CCW pump status				2	
Control room radiation level					2
Plant vent air flow rate					2
Meteorological parameters					3
Air ejector discharge radiation level					3
Air ejector delay bed exhaust radiation level concentration from					3
Service water to recirculation heat exchanger - concentration from liquid pathways					2

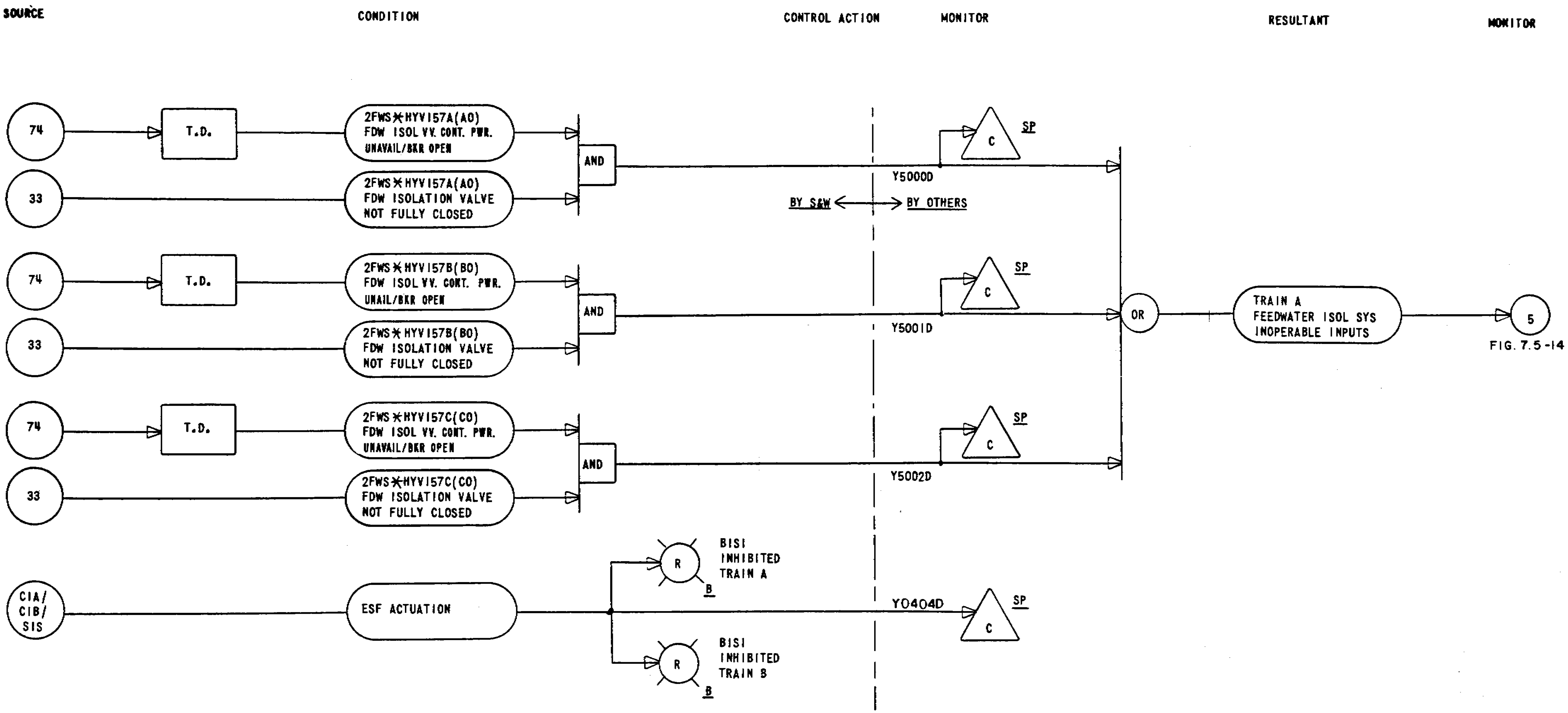
NOTES:

WR = Wide range.
NR = Narrow range.

TABLE 7.5-10

BYPASSED AND INOPERABLE STATUS INDICATION

System
Residual heat removal
Auxiliary feedwater
High head safety injection
Safety injection accumulators (Train A only)
Low head safety injection
Quench spray
Recirculation spray
Containment penetration
Service water
Primary component cooling
Fuel pool cooling
Solid state protection
Vital instrumentation electrical
Main control room ventilation isolation
Control building ventilation
Safeguards area ventilation
Cable vault and rod control area ventilation
Supplementary leak collection
Auxiliary building ventilation
Emergency switchtgear area ventilation
Battery room ventilation
Emergency diesel generator
Emergency diesel generator support
4,160 V emergency electrical
480 V emergency electrical
125 V dc emergency electrical
Intake structure ventilation
Bypassed inoperable status indication inhibited (indicating light only)

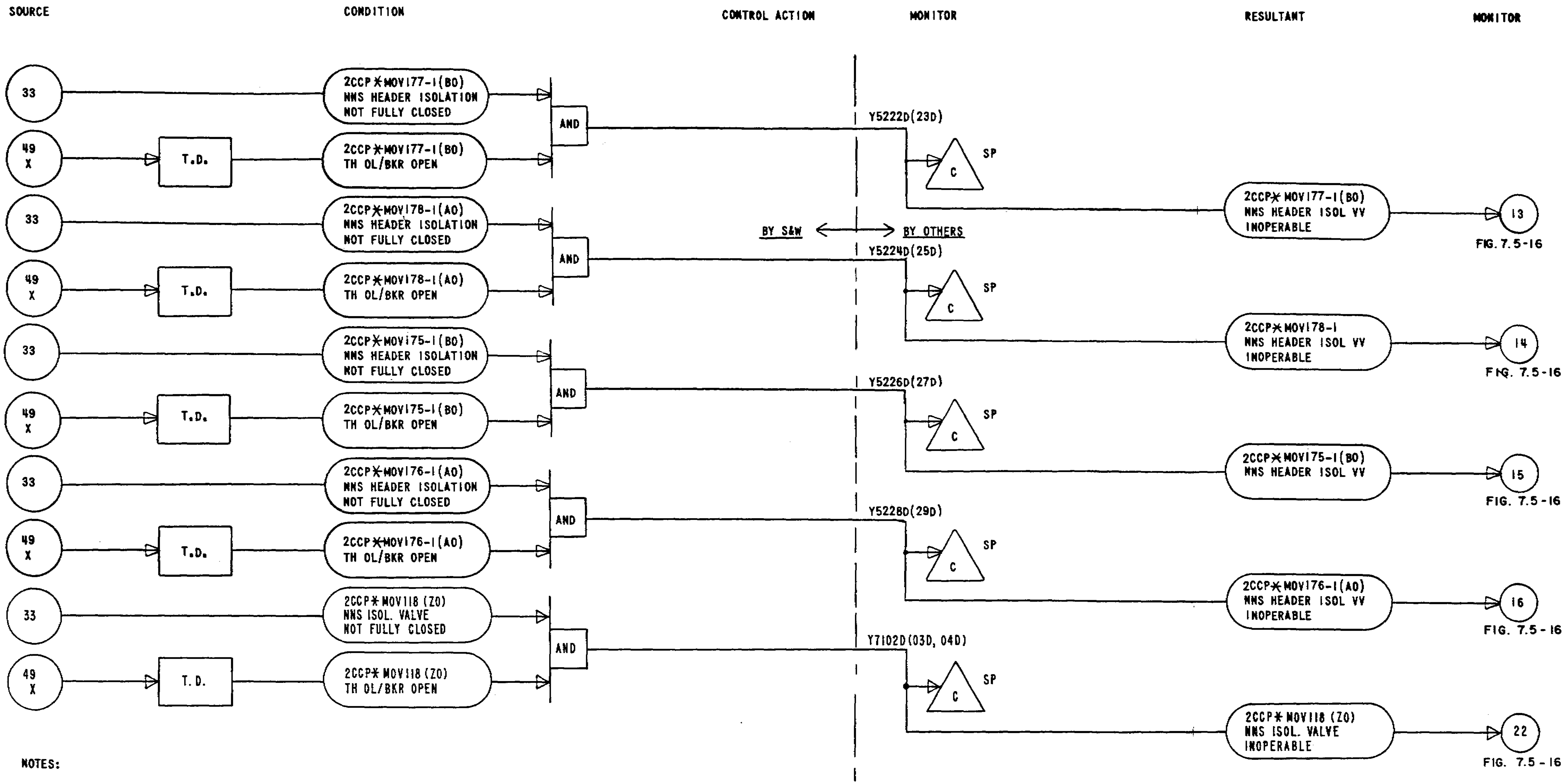


NOTES:

1. COMPUTER OUTPUTS TO THE BYPASS INDICATORS ARE TO BE INHIBITED BY THE SSOM PROGRAM WHENEVER COMPUTER ADDRESS POINT Y0404D IS IN THE ALARM STATE (=1). ESF ACTUATION IS COMMON TO TRAIN A AND TRAIN B.

2. PUSHBUTTONS SHOWN IN THIS SERIES OF DRAWINGS ACT AS BYPASS INDICATORS AND WILL BE BACK-LIT BY MANUAL ACTIVATION, OR BY OUTPUT FROM THE PCS.

FIGURE 7.5-1
BYPASSED AND INOPERABLE STATUS INDICATION – LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

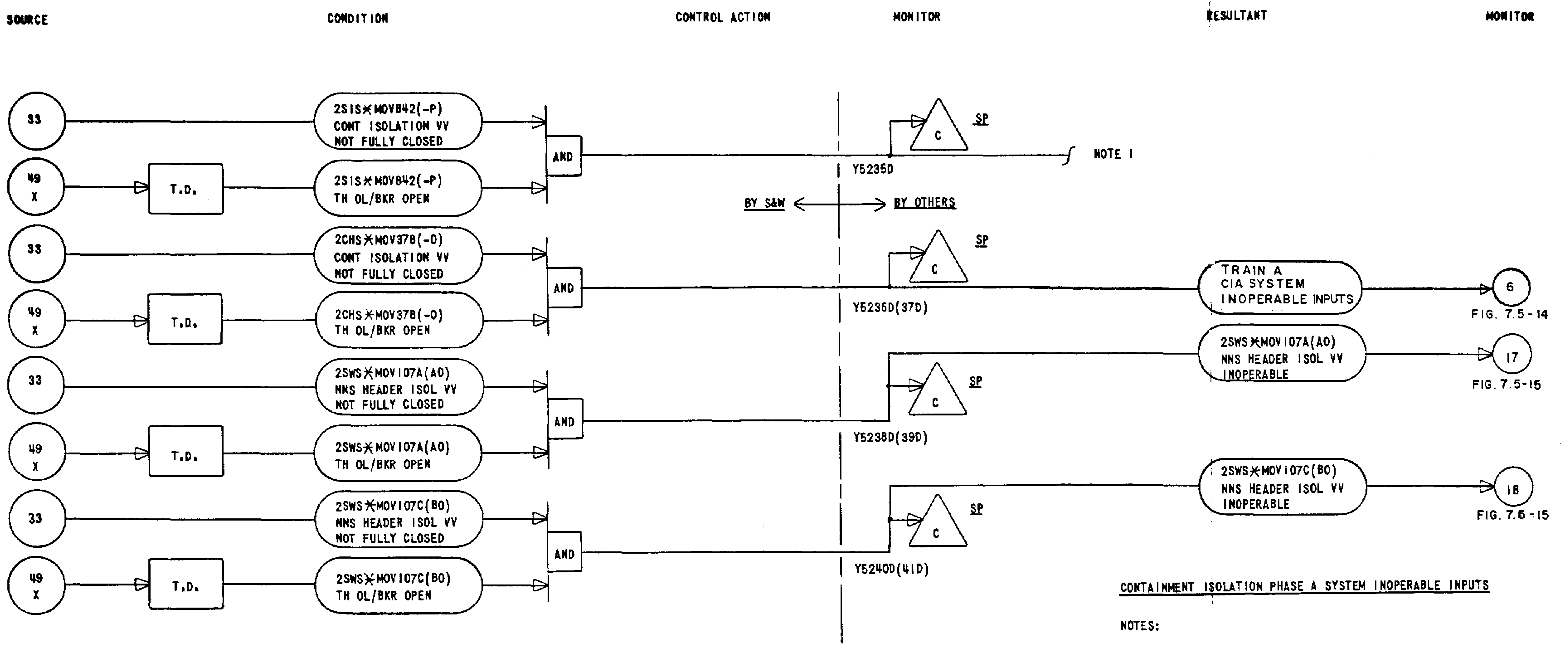
1. LOGIC FOR TRAIN A INDICATOR SHOWN, LOGIC FOR TRAIN B INDICATOR SIMILAR.

2. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2CCP✱MOV177-1(BO)	2CCP✱MOV177-2(BP)
2CCP✱MOV178-1(AO)	2CCP✱MOV178-2(AP)
2CCP✱MOV175-1(BO)	2CCP✱MOV175-2(BP)
2CCP✱MOV176-1(AO)	2CCP✱MOV176-2(AP)
2CCP✱MOV118 (ZO)	2CCP✱MOV119 (ZP) 2CCP✱MOV120 (ZP)

3. SEE NOTE 1 ON FIG. 7.5-1.

FIGURE 7.5-2
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



CONTAINMENT ISOLATION PHASE A SYSTEM INOPERABLE INPUTS

NOTES:

1. TRAIN B ONLY

2. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
——	2SIS✱MOV842(-P)
2CHS✱MOV378(-O)	2CHS✱MOV381(-P)
2SWS✱MOV107A(AO)	2SWS✱MOV107B(AP)
2SWS✱MOV107C(BO)	2SWS✱MOV107D(BP)

3. SEE NOTE 1 ON FIG. 7.5-1.

FIGURE 7.5-3
BYPASSED AND INOPERABLE STATUS INDICATION - LOGIC DIAGRAM
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

No. 10080-LSK-27-30D

NOTES:

1. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN. LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.
2. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2SWS-MOV152-1(BO)	2SWS-MOV152-2(BP)
2SWS-MOV155-1(BO)	2SWS-MOV155-2(BP)

3. SEE NOTE 1 ON LSK-27-30A.
4. ALL ASTERISKS (*) HAVE BEEN REPLACED BY DASHES. REFER TO THE ASSET EQUIPMENT LIST (AEL) AS THE OFFICIAL LISTING OF ANY ASSET'S QA CATEGORY.

UFSAR FIGURE 7.5-4
O.M. FIGURE 47-23

ISSUES					
6	MINOR DWG. CHANGE CR-01-2733 ADDED UFSAR FIG. NO.	MINOR DWG. CHANGE ADDED O.M. FIG. NO. & NOTE 4.			
7	ECP 04-0514 CR 04-08950 INCORPORATED IDCN 2-LSK-027-030D-E04-0514-01	JJD 12-01-04 D/CHK: SWG	SUP: E.E.EBECK 1/3/05		
8	ECP 04-0514 CR 04-08950 INCORPORATED IDCN 2-LSK-027-030D-E04-0514-01 AND ENG REDLINE INFO	SWG 4-10-05 D/CHK: PMT	SUP: E.E.Ebeck	ENG: E.E.Ebeck	MGR: [illegible]

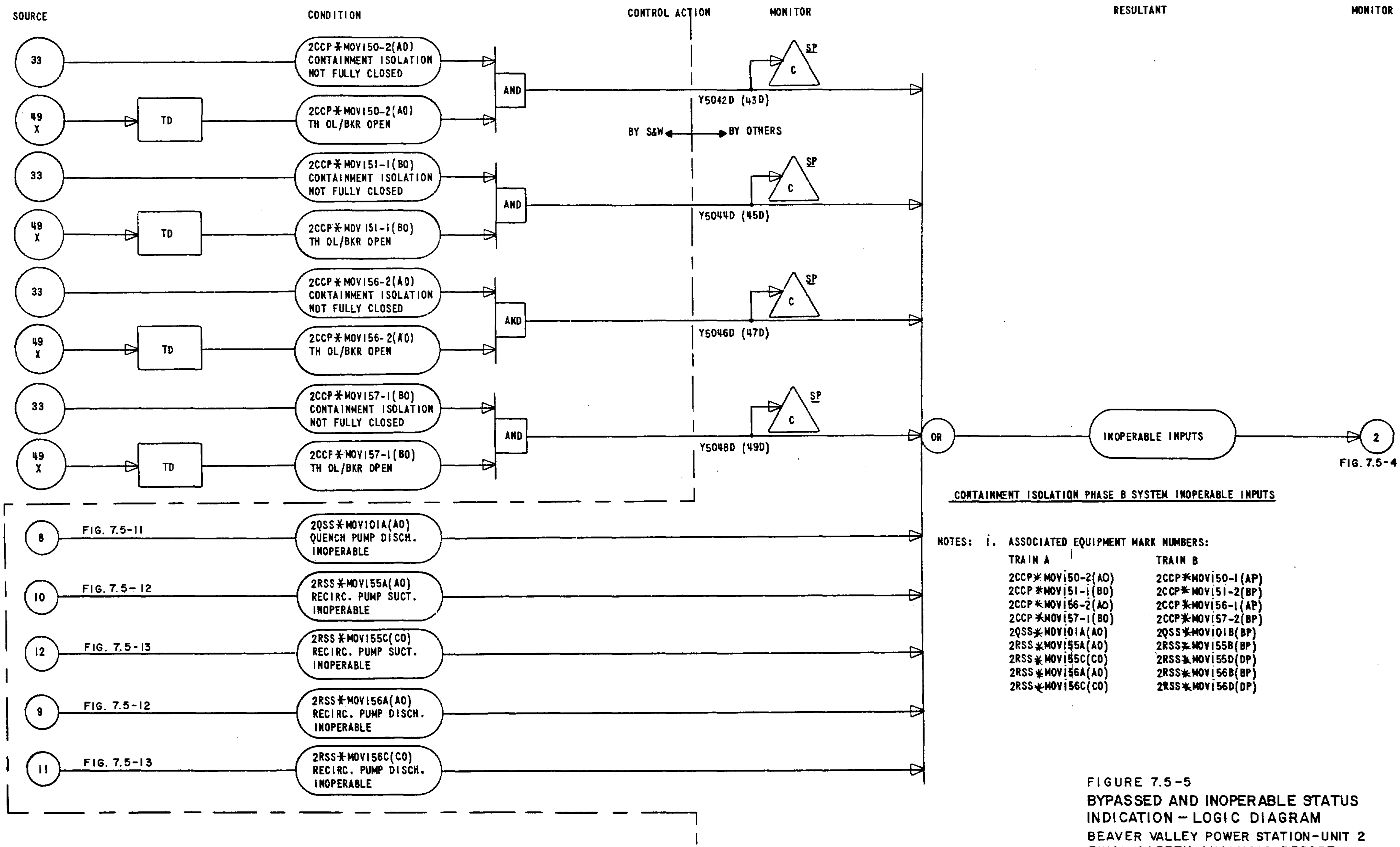
FENOC FIRSTENERGY NUCLEAR OPERATING COMPANY

BEAVER VALLEY POWER STATION UNIT 2

LOGIC DIAGRAM - BYPASSED AND INOPERABLE STATUS INDICATION

SCALE	DATE	11-1-01	ARCH.APP.	
NTS	DRAWN BY	R.W.ROTH	ELECT.APP.	N/A
	DFG./CHK	RJK TGZ	MECH.APP.	
	ENGR./CHK	N/A	CIVIL APP.	

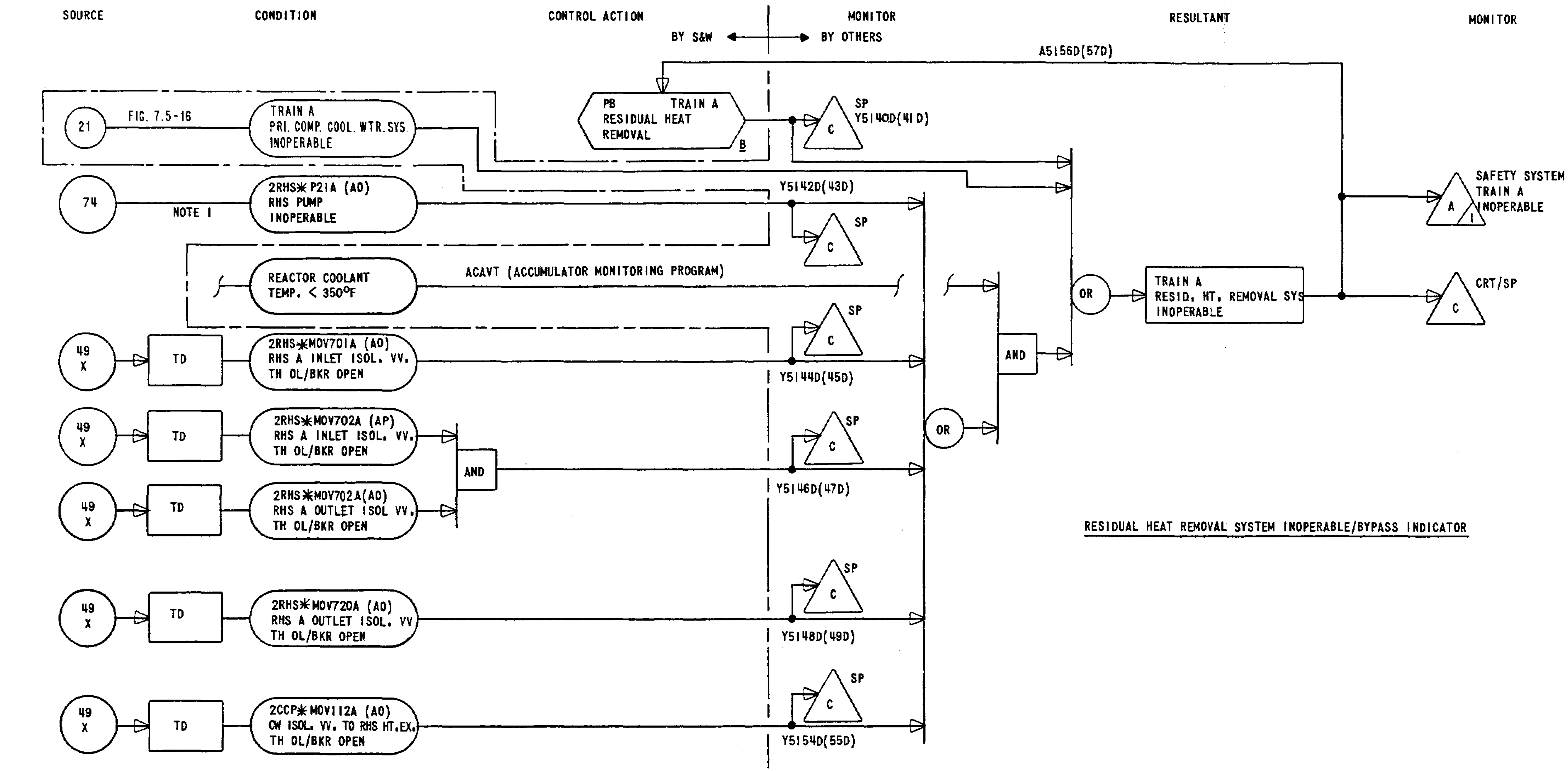
FINAL APP. FOR ISSUE MGR/SUP: TGZ/RD 12-1-01 — STA. NO. 100014 — A — DWG.NO. 10080-LSK-27-30D — REV. 8



NOTES: 1. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2CCP*MOV150-2(AO)	2CCP*MOV150-1(AP)
2CCP*MOV151-1(BO)	2CCP*MOV151-2(BP)
2CCP*MOV156-2(AO)	2CCP*MOV156-1(AP)
2CCP*MOV157-1(BO)	2CCP*MOV157-2(BP)
2QSS*MOV101A(AO)	2QSS*MOV101B(BP)
2RSS*MOV155A(AO)	2RSS*MOV155B(BP)
2RSS*MOV155C(CO)	2RSS*MOV155D(DP)
2RSS*MOV156A(AO)	2RSS*MOV156B(BP)
2RSS*MOV156C(CO)	2RSS*MOV156D(DP)

FIGURE 7.5-5
BYPASSED AND INOPERABLE STATUS
INDICATION – LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES: 1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT," OR LOSS OF CONTROL POWER.

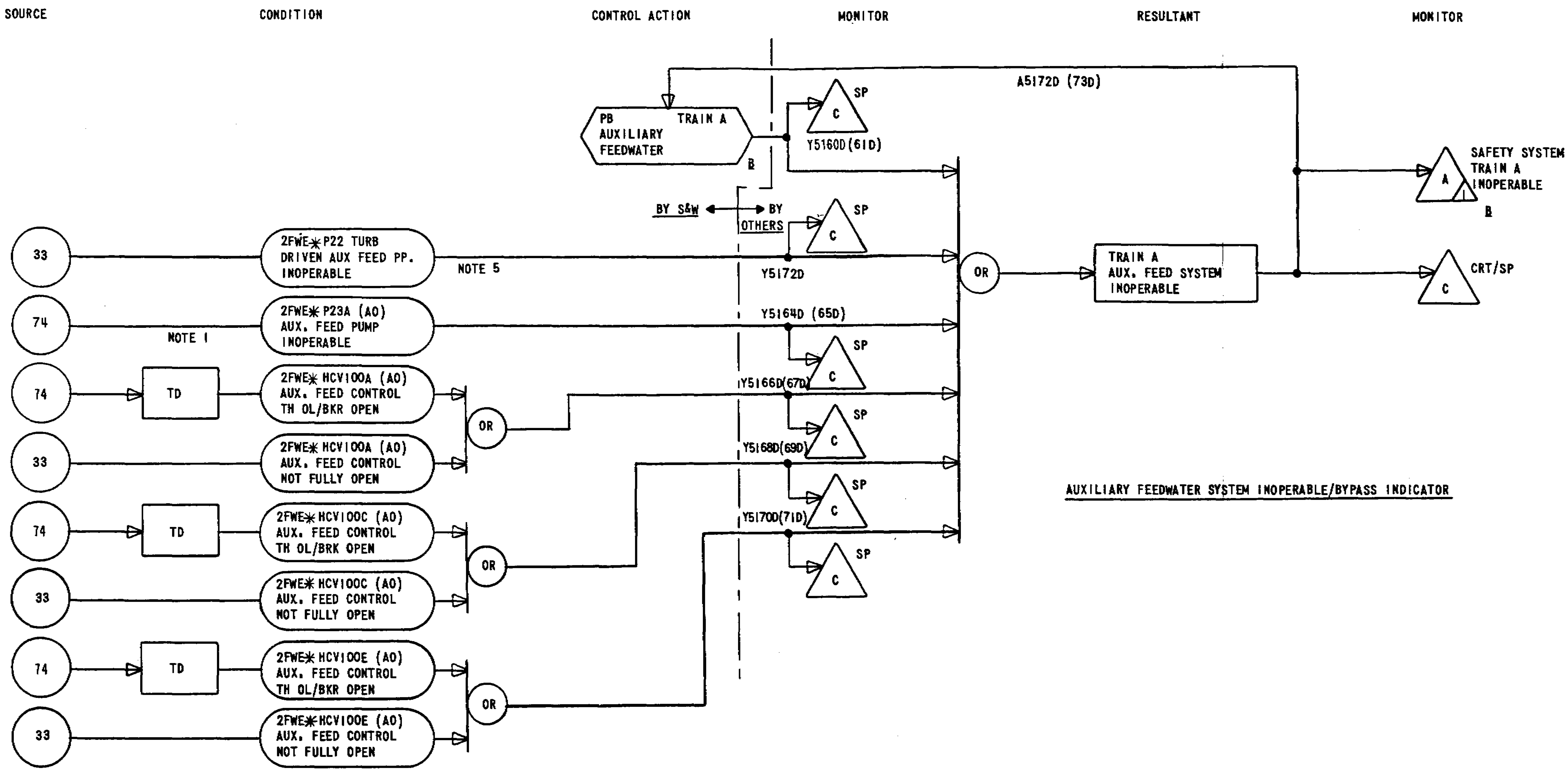
2. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN, LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.

3. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

4. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2RHS*P21A(AO)	2RHS*P21B(BO)
2RHS*MOV701A(AO)	2RHS*MOV701B(BO)(BP)
2RHS*MOV702A(AP)(AO)	2RHS*MOV702B(BP)
2RHS*MOV720A(AO)	2RHS*MOV720B(BP)
2CCP*MOV112A(AO)	2CCP*MOV112B(BP)

FIGURE 7.5-6
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

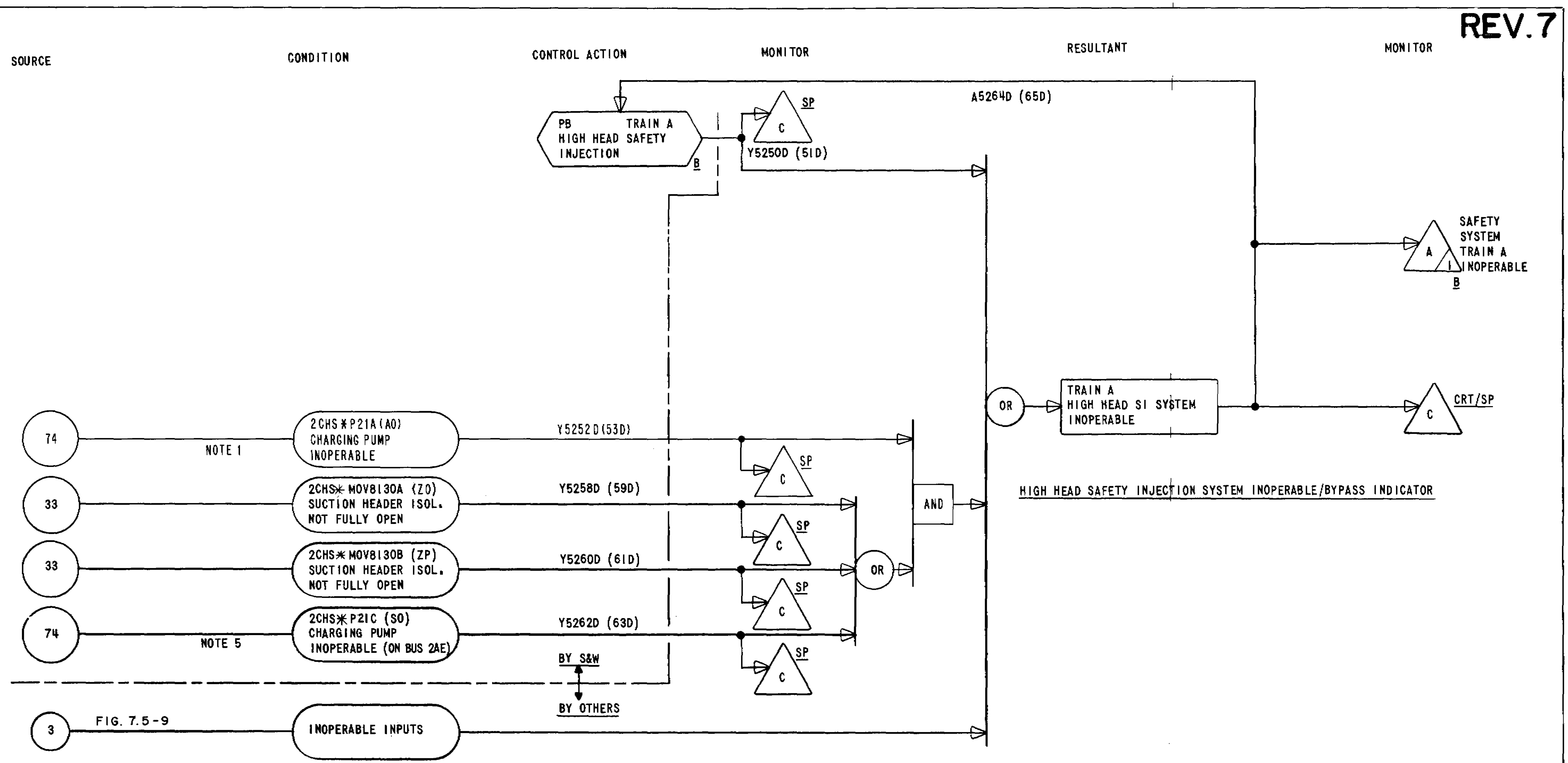


NOTES:
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT," OR LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A INDICATOR SHOWN, LOGIC FOR TRAIN B INDICATOR SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2FWE✱P22	2FWE✱P23B(BP)
2FWE✱P23A(AO)	2FWE✱HCV100B(BP)(BW)
2FWE✱HCV100A(AO)(AR)	2FWE✱HCV100D(BP)(BW)
2FWE✱HCV100C(AO)(AR)	2FWE✱HCV100F(BP)(BW)
2FWE✱HCV100E(AO)(AR)	

4. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
5. INPUT EXISTS WHENEVER OVERSPEED LATCH BAR ON THE TURBINE HAS NOT BEEN RESET. THIS INPUT APPLIES TO THE TRAIN A BYPASS INDICATOR ONLY.

FIGURE 7.5-7
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

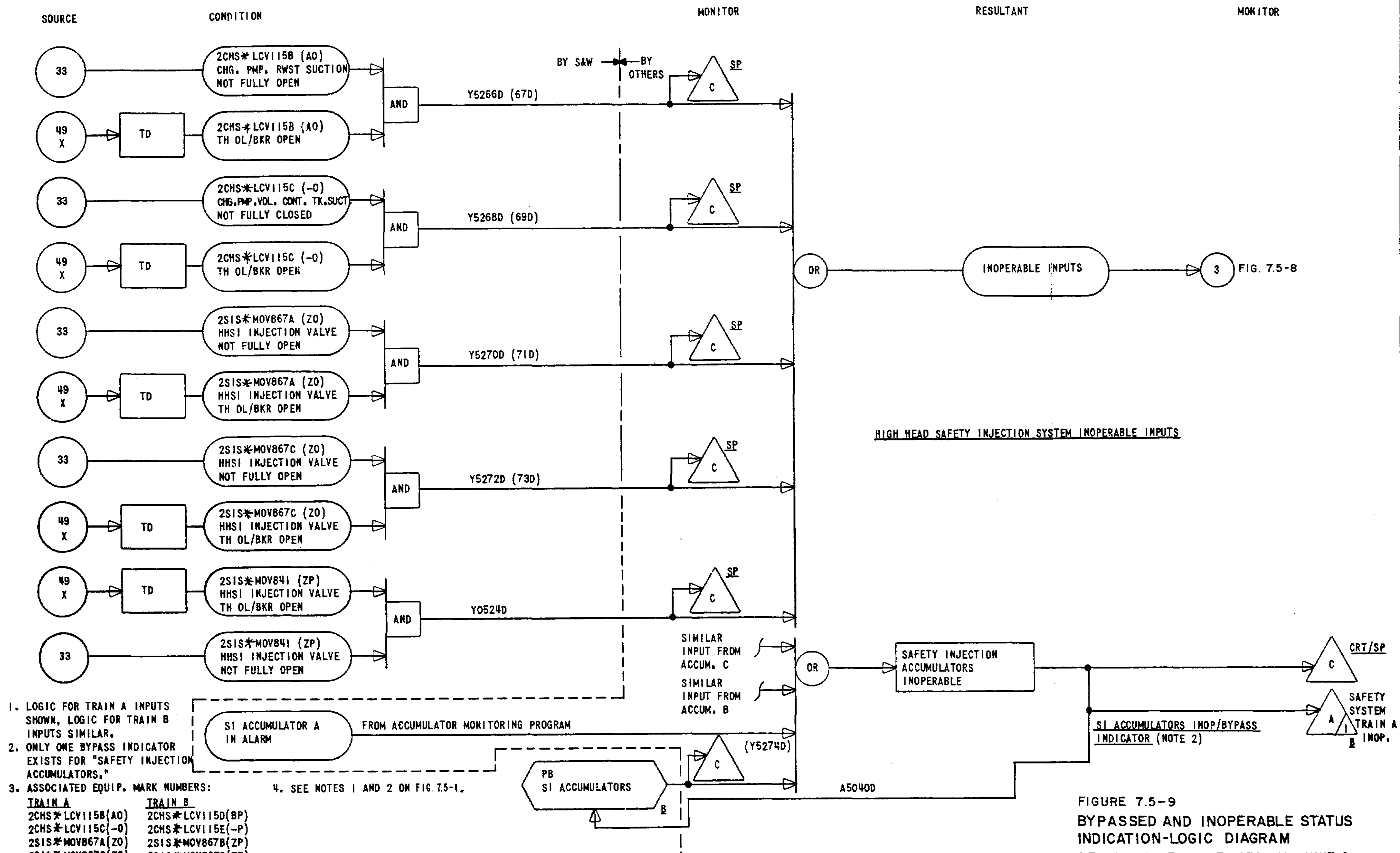


NOTES:
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT," OR, LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN, LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.
3. SEE NOTES 1 AND 2 ON FIG.7.5-1.
4. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2CHS*P21A (AO)	2CHS*P21B (BP)
2CHS*P21C (SO), BUS 2AE	2CHS*P21C (SP) BUS 2DF
2CHS*MOV8130A (ZO)	2CHS*MOV8131A (ZO)
2CHS*MOV8130B (ZP)	2CHS*MOV8131B (ZP)
2CHS*MOV380A (AO)	2CHS*MOV380B (BO)
2CHS*MOV383A (AP)	2CHS*MOV383B (BO)

5. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCK," LOSS OF CONTROL POWER, OR P21A BREAKER RACKED IN.

FIGURE 7.5-8
BYPASSED AND INOPERABLE STATUS INDICATION – LOGIC DIAGRAM
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

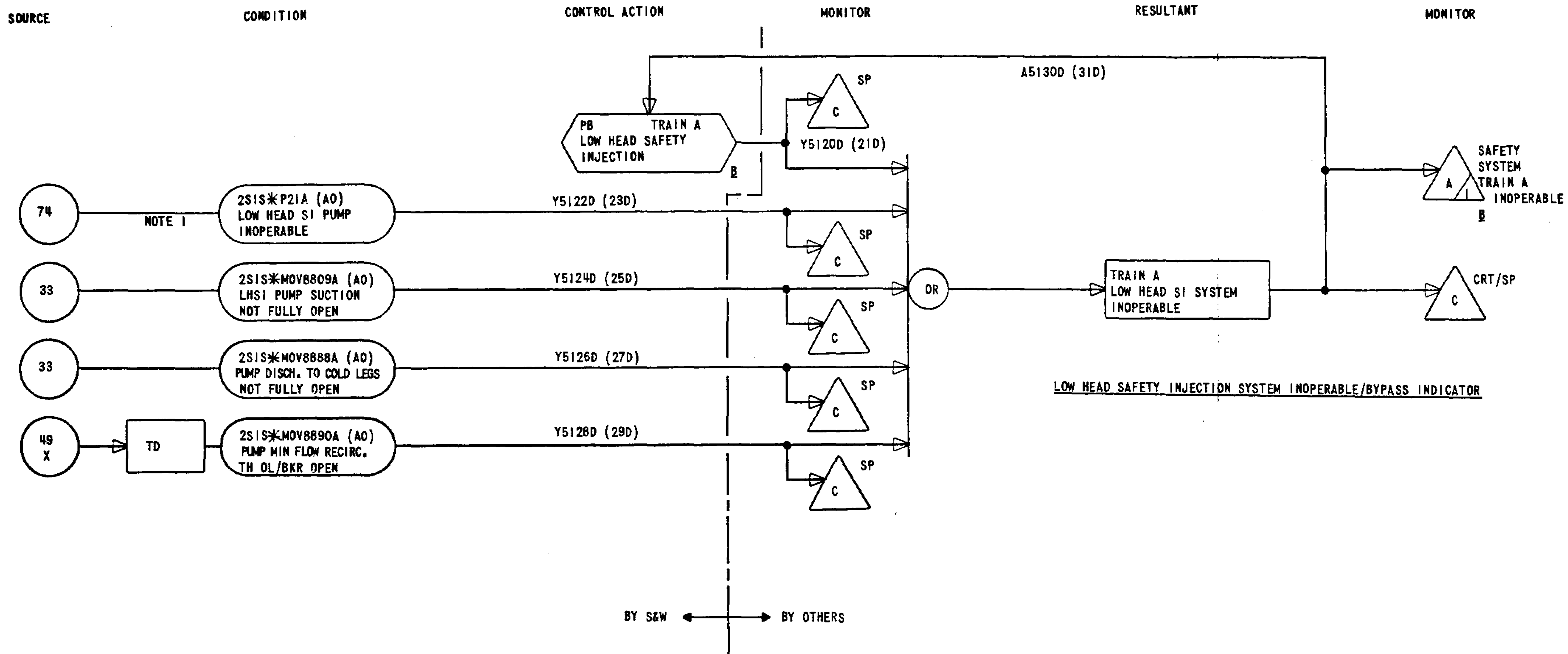


1. LOGIC FOR TRAIN A INPUTS SHOWN, LOGIC FOR TRAIN B INPUTS SIMILAR.
2. ONLY ONE BYPASS INDICATOR EXISTS FOR "SAFETY INJECTION ACCUMULATORS."
3. ASSOCIATED EQUIP. MARK NUMBERS:

TRAIN A	TRAIN B
2CHS*LCV115B(AO)	2CHS*LCV115D(BP)
2CHS*LCV115C(-O)	2CHS*LCV115E(-P)
2SIS*MOV867A(ZO)	2SIS*MOV867B(ZP)
2SIS*MOV867C(ZO)	2SIS*MOV867D(ZP)
2SIS*MOV841 (ZP)	

4. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

FIGURE 7.5-9
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT



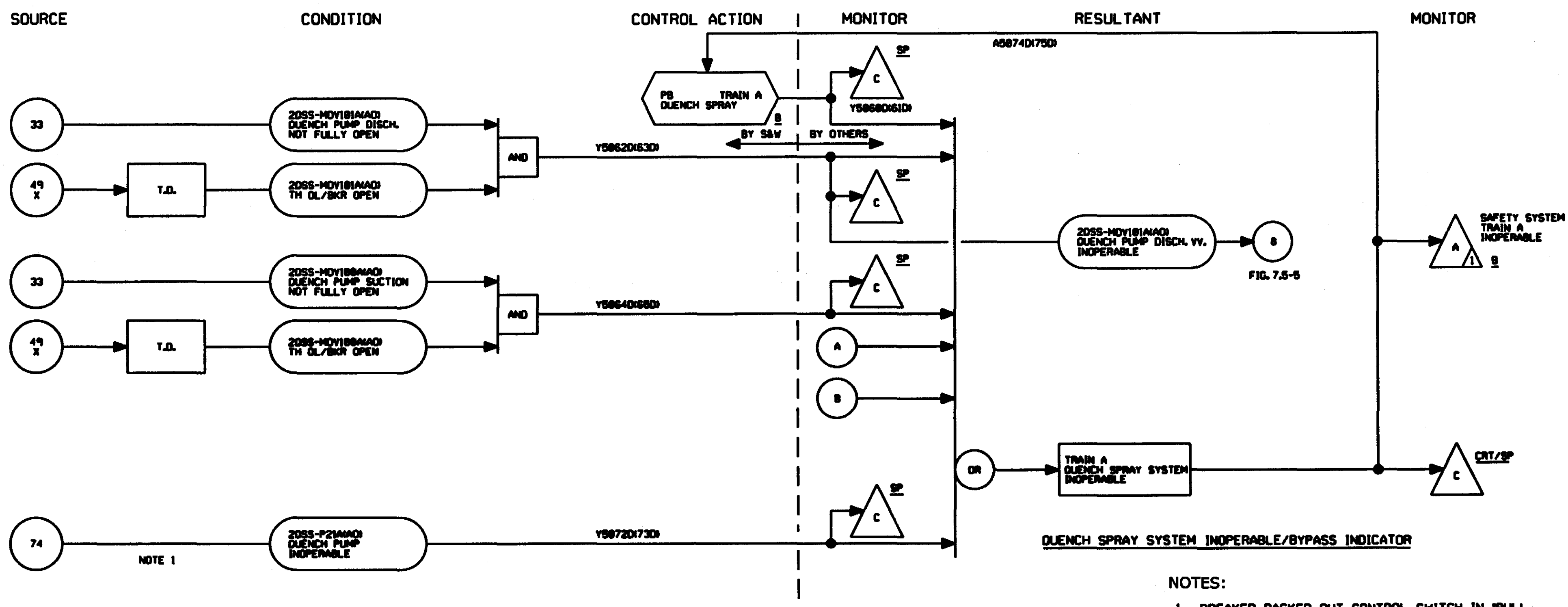
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT", OR, LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN, LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2SIS✱P21A (AO)	2SIS✱P21B (BP)
2SIS✱MOV8809A (AO)	2SIS✱MOV8809B (BP)
2SIS✱MOV8888A (AO)	2SIS✱MOV8888B (BP)
2SIS✱MOV8890A (AO)	2SIS✱MOV8890B (BP)

4. SEE NOTE 1 AND 2 ON FIG. 7.5-1.

FIGURE 7.5-10
BYPASSED AND INOPERABLE STATUS
INDICATION—LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 18



QUENCH SPRAY SYSTEM INOPERABLE/BYPASS INDICATOR

NOTES:

1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT", OR LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN, LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.
3. SEE NOTES 1 AND 2 ON LSK-27-30A.
4. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2QSS-MOV100A(AO)	2QSS-MOV100B(BP)
2QSS-MOV101A(AO)	2QSS-MOV101B(BP)
2QSS-P21A(AO)	2QSS-P21B(BP)

5. DENOTES LOSS OF POWER, CONTROL SWITCH IN "PULL TO LOCKOUT", OR MOTOR THERMAL OVERLOAD.
6. ALL ASTERISKS (*) HAVE BEEN REPLACED BY DASHES. REFER TO THE ASSET EQUIPMENT LIST (AEL) AS THE OFFICIAL LISTING OF ANY ASSET'S QA CATEGORY.

UFSAR FIGURE 7.5-11

BYPASSED AND INOPERABLE STATUS INDICATION - LOGIC DIAGRAM

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

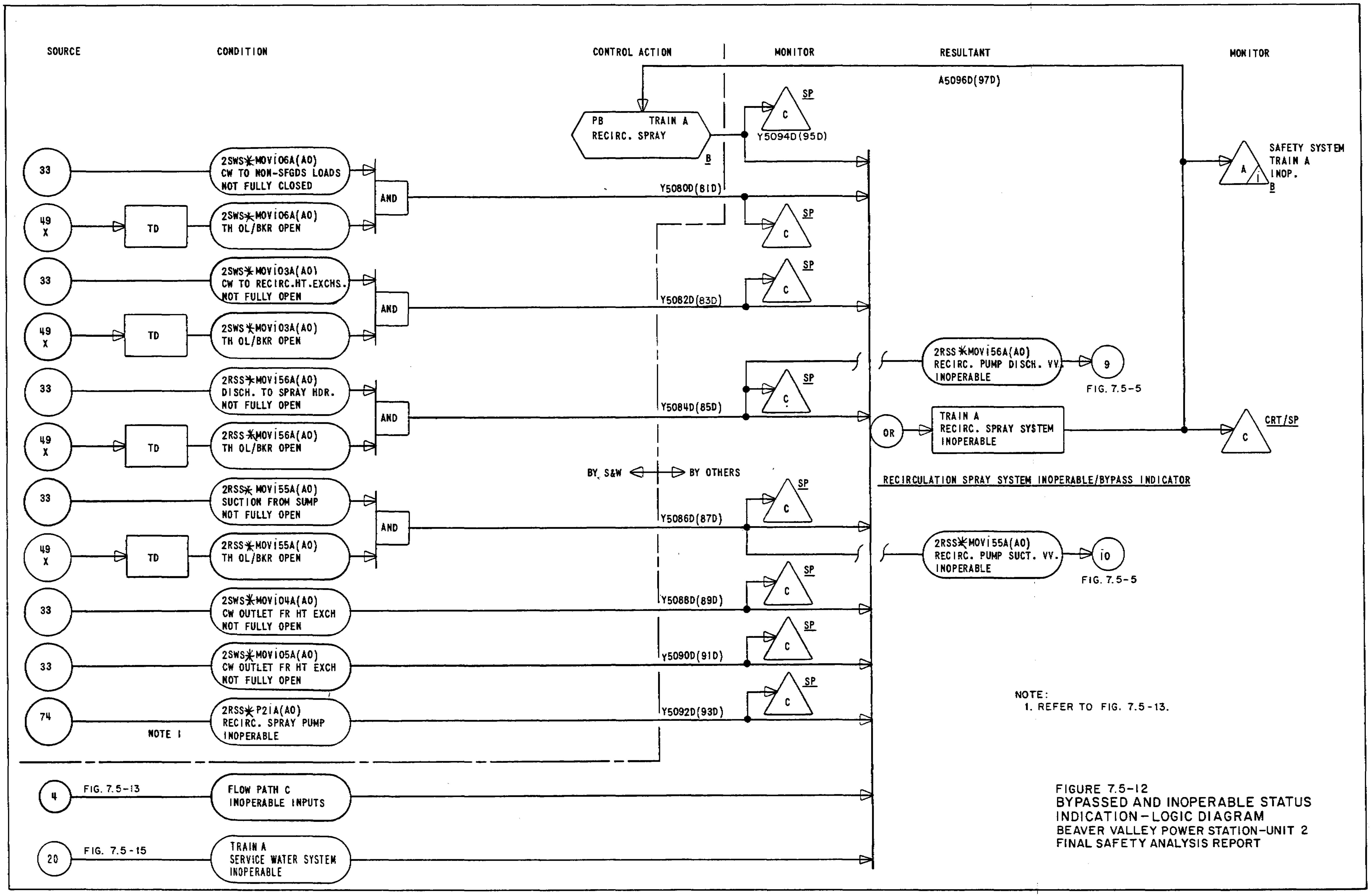
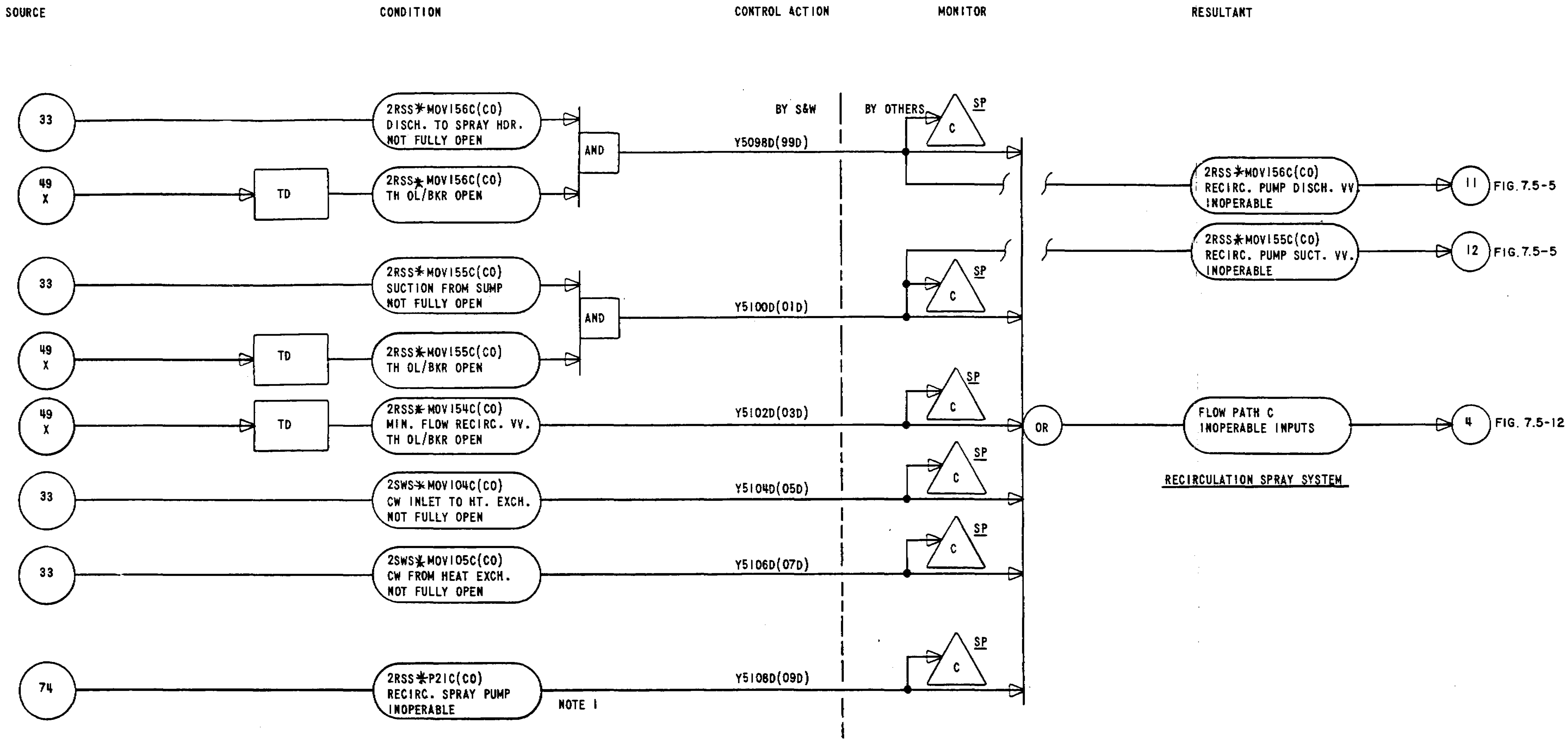


FIGURE 7.5-12
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



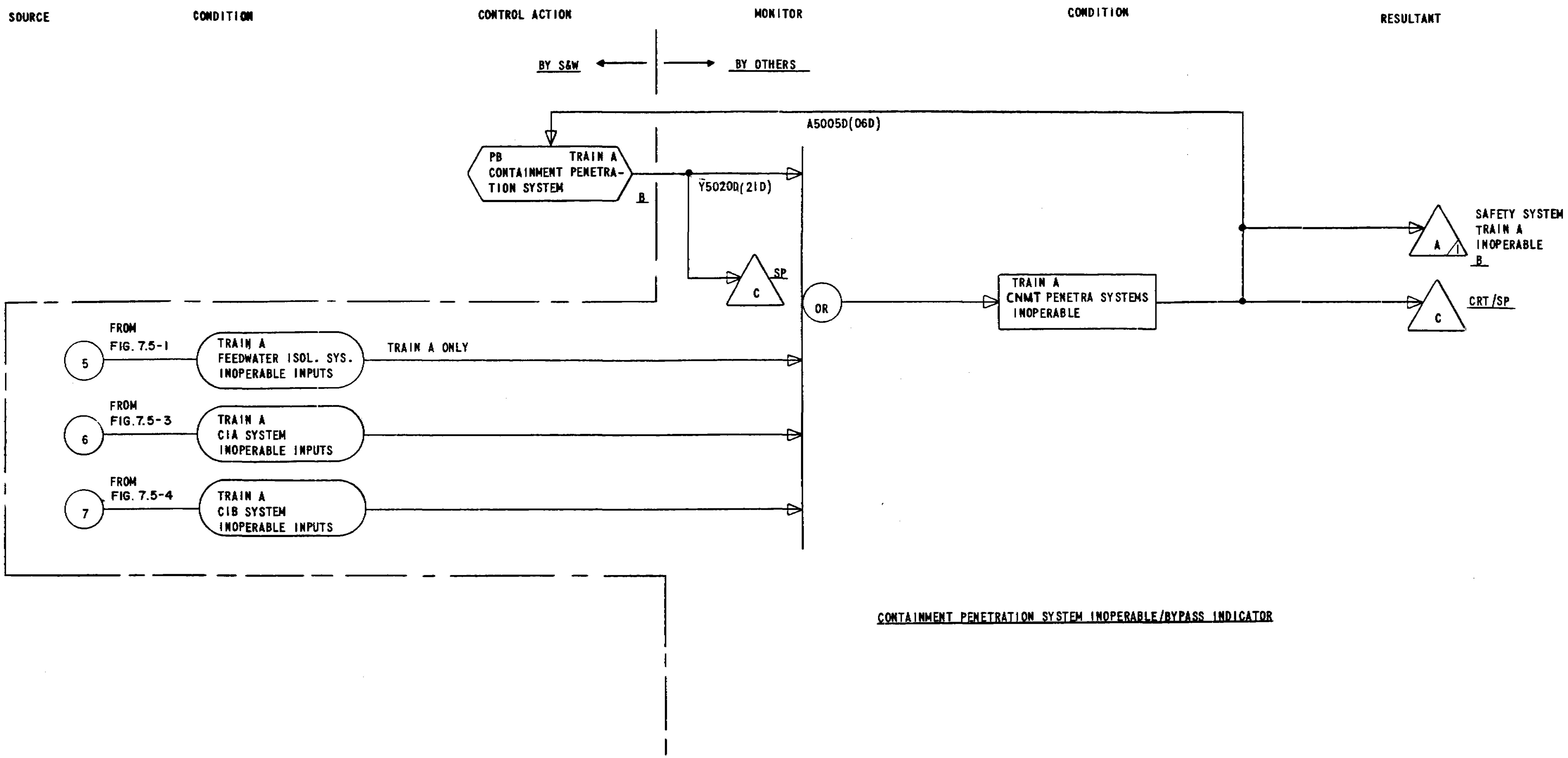
NOTES:
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT," OR LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A
2RSS*P21A(AO) *P21C(CO)
2RSS*MOV155A(AO), *MOV156A(AO)
2RSS*MOV155C(CO), *MOV156C(CO)
2RSS*MOV154C(CO)
2SWS*MOV104A(AO), 2SWS*MOV105A(AO)
2SWS*MOV104C(CO), 2SWS*MOV105C(CO)
2SWS*MOV103A(AO)
2SWS*MOV106A(AO)

TRAIN B
2RSS*P21B(BP), *P21D(DP)
2RSS*MOV155B(BP), *MOV156B(BP)
2RSS*MOV155D(DP), *MOV156D(DP)
2RSS*MOV154D(DP)
2SWS*MOV104B(BP), 2SWS*MOV105B(BP)
2SWS*MOV104D(DP), 2SWS*MOV105D(DP)
2SWS*MOV103B(BP)
2SWS*MOV106B(BP)

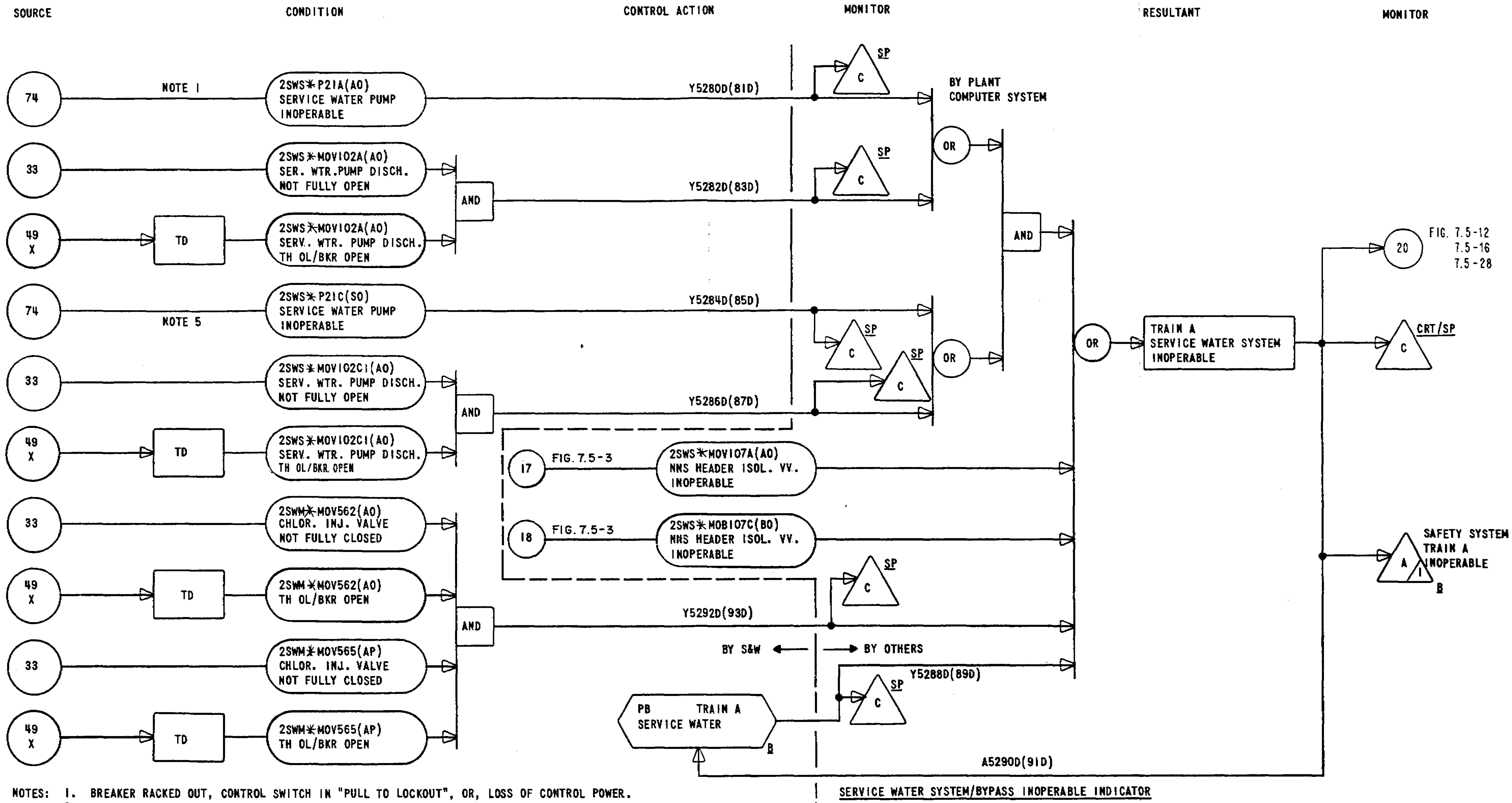
4. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

FIGURE 7.5-13
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN
LOGIC FOR TRAIN B SIMILAR.

FIGURE 7.5-14
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT", OR, LOSS OF CONTROL POWER.
2. TRAIN A BYPASS INDICATOR SHOWN, TRAIN B BYPASS INDICATOR SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A

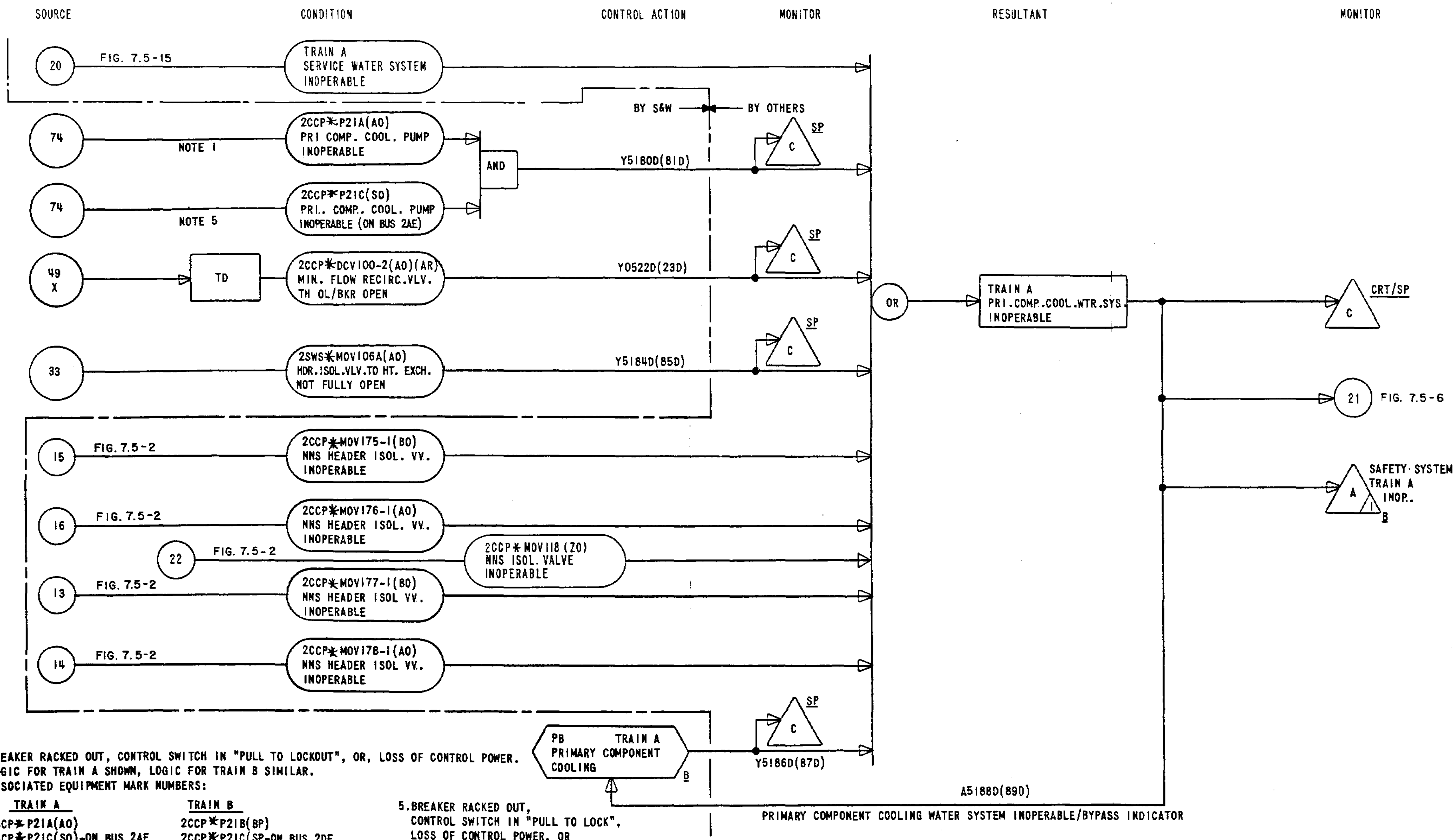
2SWS✱P21A(AO)
2SWS✱MOV102A(AO)
2SWS✱P21C(SO)
2SWS✱MOV102C1(AO)
2SWM✱MOV562(AO)
2SWM✱MOV265(AP)
2SWS✱MOV107A(AO)
2SWS✱MOV107C(BO)

TRAIN B

2SWS✱P21B(BP)
2SWS✱MOV102B(BP)
2SWS✱P21C(SP)
2SWS✱MOV102C2(BP)
2SWM✱MOV563(BP)
2SWM✱MOV564(BO)
2SWS✱MOV107B(AP)
2SWS✱MOV107D(BP)

4. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
5. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCK", LOSS OF CONTROL POWER OR P21A BREAKER RACKED IN.

FIGURE 7.5-15
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

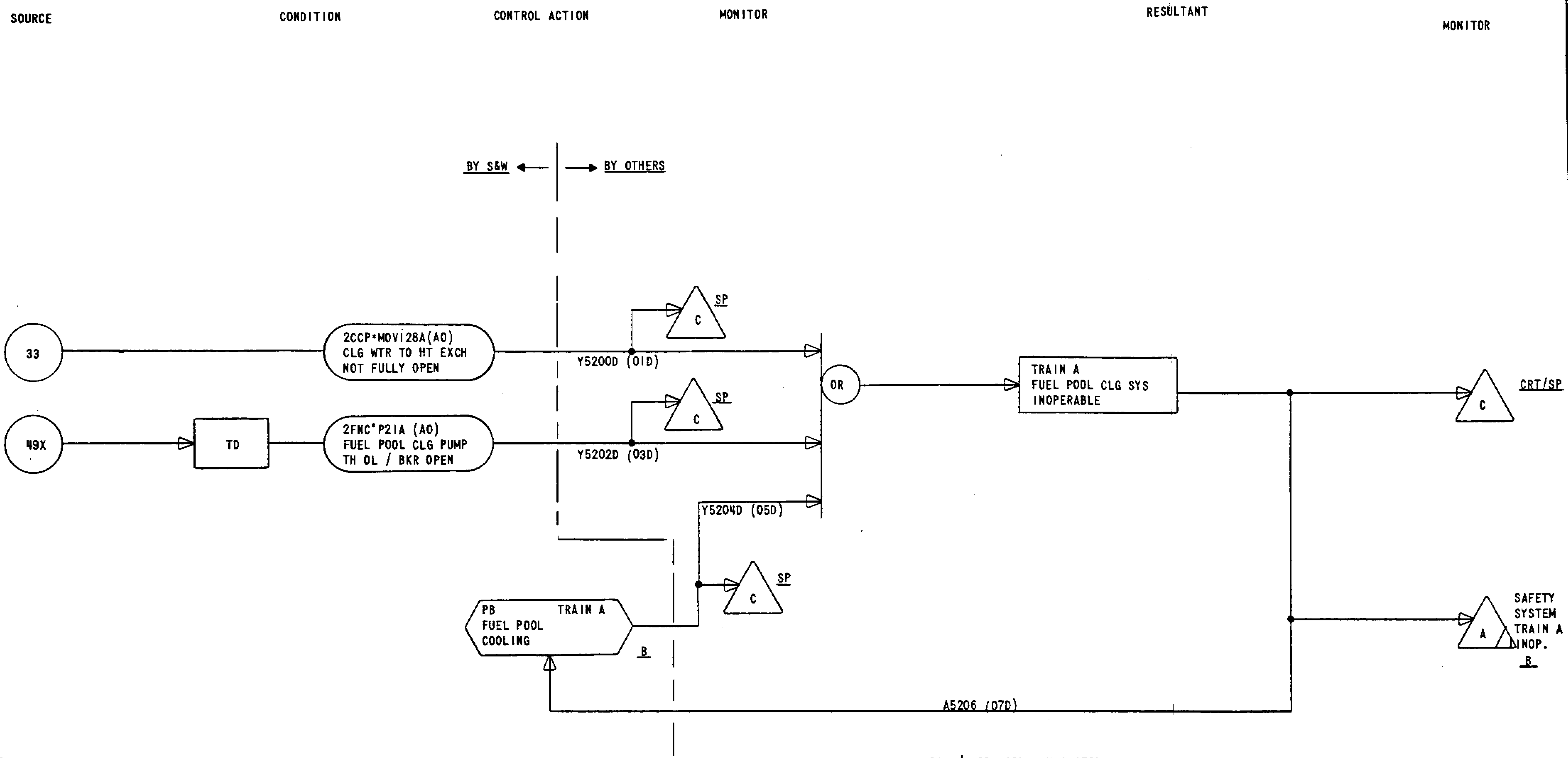
1. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCKOUT", OR, LOSS OF CONTROL POWER.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2CCP*P21A(AO)	2CCP*P21B(BP)
2CCP*P21C(SO)-ON BUS 2AE	2CCP*P21C(SP-ON BUS 2DF
2CCP*DCV100-2(AO)(AR)	2CCP*DCV100-1(BP)(BW)
2SWS*MOV106A(AO)	2SWS*MOV106B(BP)
2CCP*MOV175-1(BO),176-1(AO)	2CCP*MOV175-2(BP),176-2(AP)
2CCP*MOV177-1(BO),178-1(AO)	2CCP*MOV177-2(BP),178-2(AP)
2CCP*MOV118 (ZO)	2CCP*MOV119 (ZP),120 (ZP)

4. SEE NOTE 1 AND 2 ON FIG. 7.5-14.

5. BREAKER RACKED OUT, CONTROL SWITCH IN "PULL TO LOCK", LOSS OF CONTROL POWER, OR P21A BREAKER RACKED IN.

FIGURE 7.5-16
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

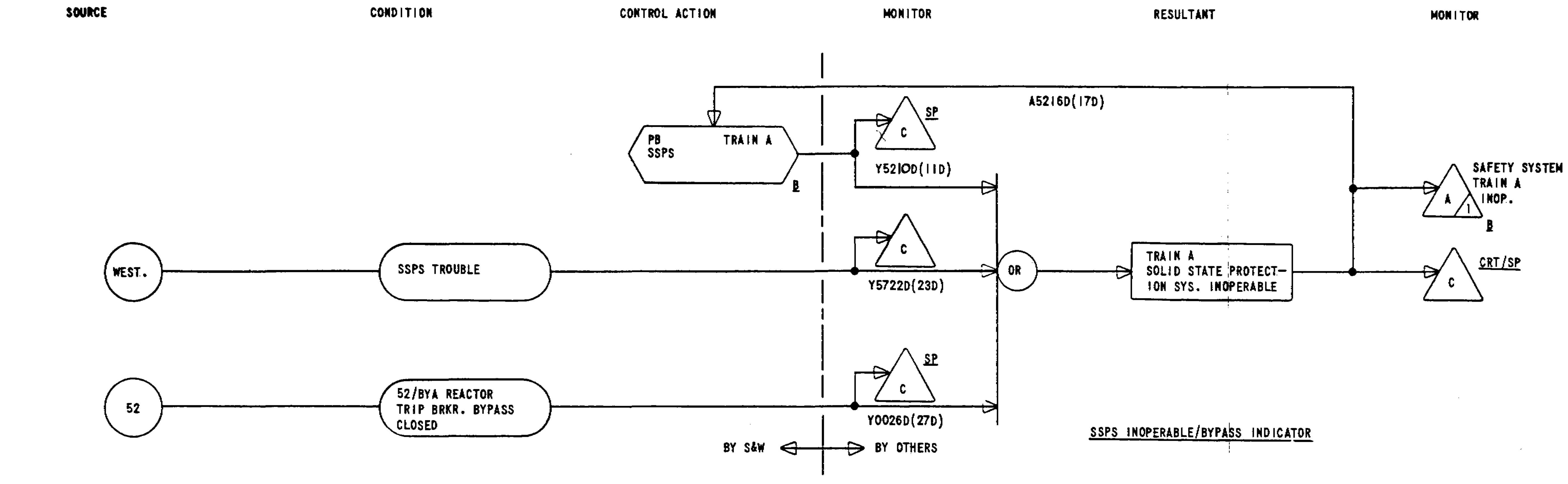


NOTES:
1. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
2. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2CCP*MOV128A(AO)	2CCP*MOV128B (BP)
2FNC*P21A (AO)	2FNC*P21B (BP)

3. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

FIGURE 7.5-17
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



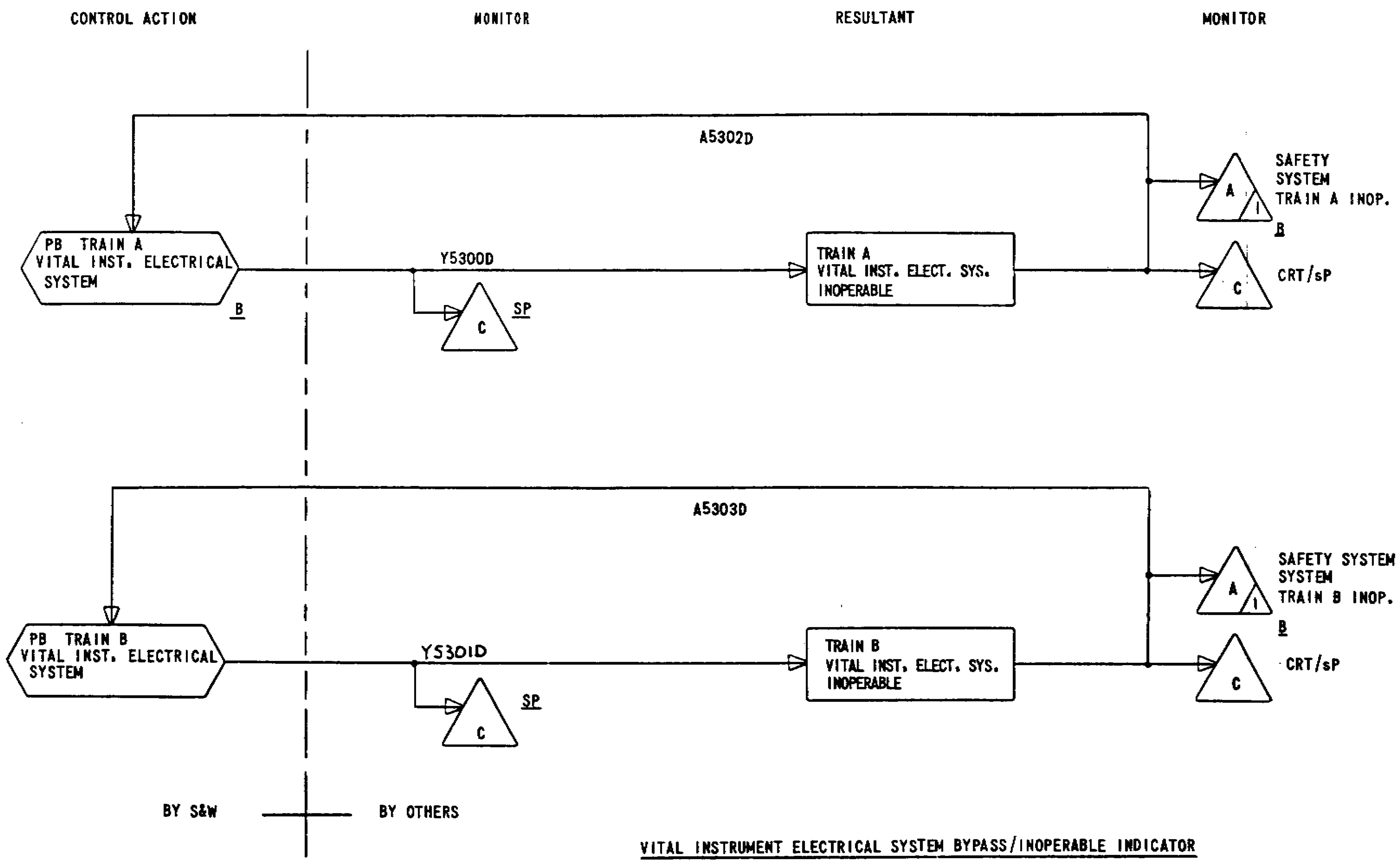
NOTES: 1. LOGIC FOR TRAIN A BYPASS INDICATOR SHOWN,
LOGIC FOR TRAIN B BYPASS INDICATOR SIMILAR.

2. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
52/BYA	52/BYB

3. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

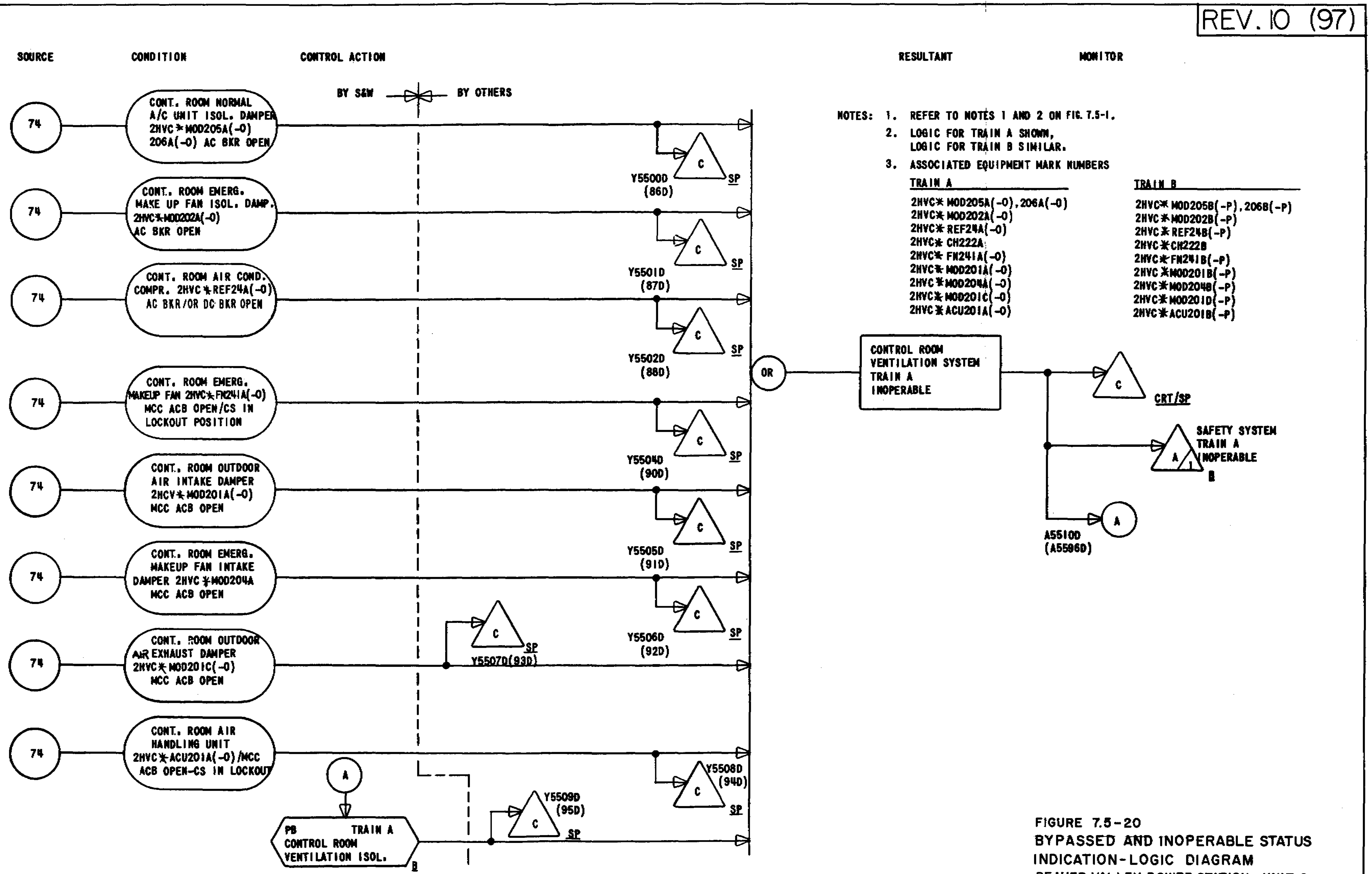
FIGURE 7.5-18
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTE:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.

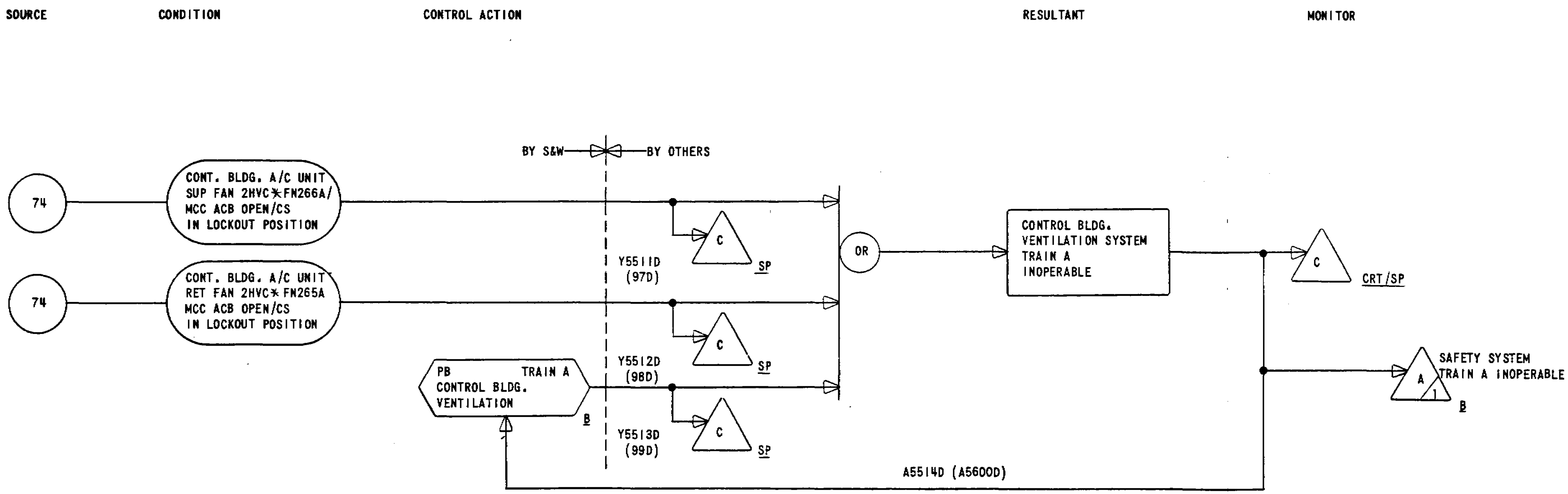
FIGURE 7.5-19
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. REFER TO NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS

TRAIN A	TRAIN B
2HVC* MOD205A(-O),206A(-O)	2HVC* MOD205B(-P),206B(-P)
2HVC* MOD202A(-O)	2HVC* MOD202B(-P)
2HVC* REF24A(-O)	2HVC* REF24B(-P)
2HVC* CH222A	2HVC* CH222B
2HVC* FN241A(-O)	2HVC* FN241B(-P)
2HVC* MOD201A(-O)	2HVC* MOD201B(-P)
2HVC* MOD204A(-O)	2HVC* MOD204B(-P)
2HVC* MOD201C(-O)	2HVC* MOD201D(-P)
2HVC* ACU201A(-O)	2HVC* ACU201B(-P)

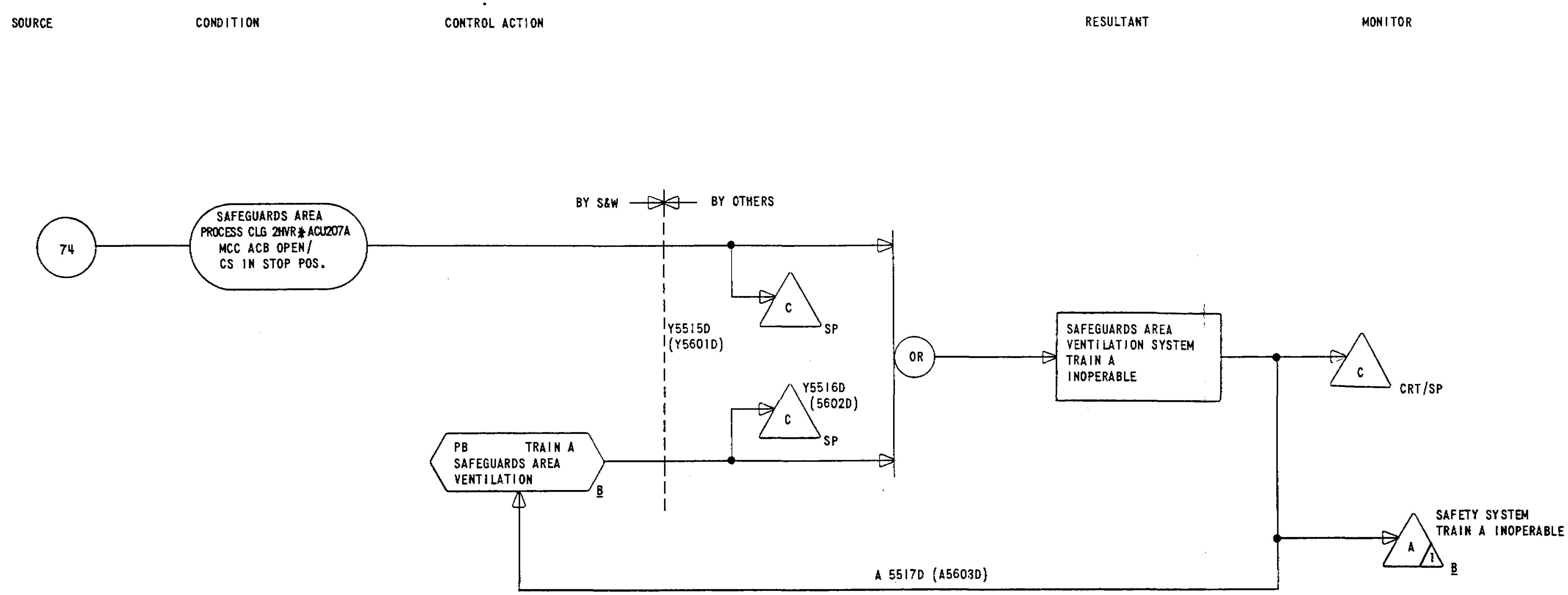
FIGURE 7.5-20
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVC*FN266A	2HVC*FN266B
2HVC*FN265A	2HVC*FN265B

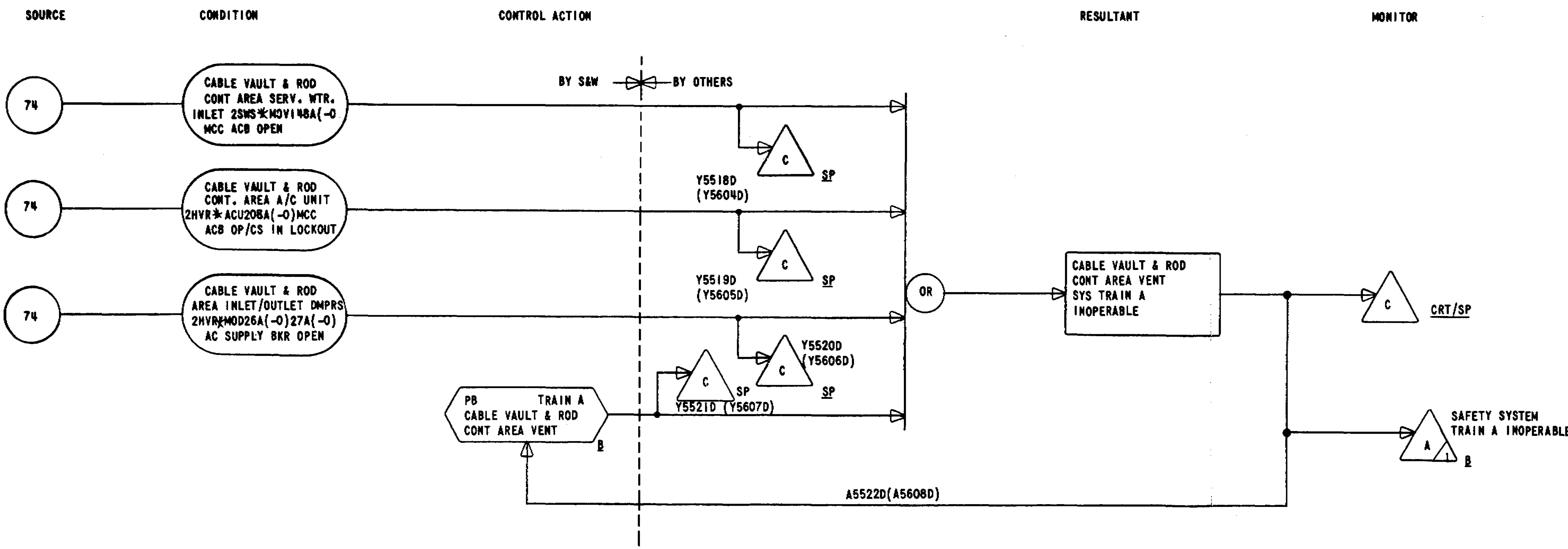
FIGURE 7.5-21
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE NOTES 1 AND 2 ON FIG. 7.5-1,
2. LOGIC FOR TRAIN A SHOWN,
LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVR*ACU207A	2HVR*ACU207B

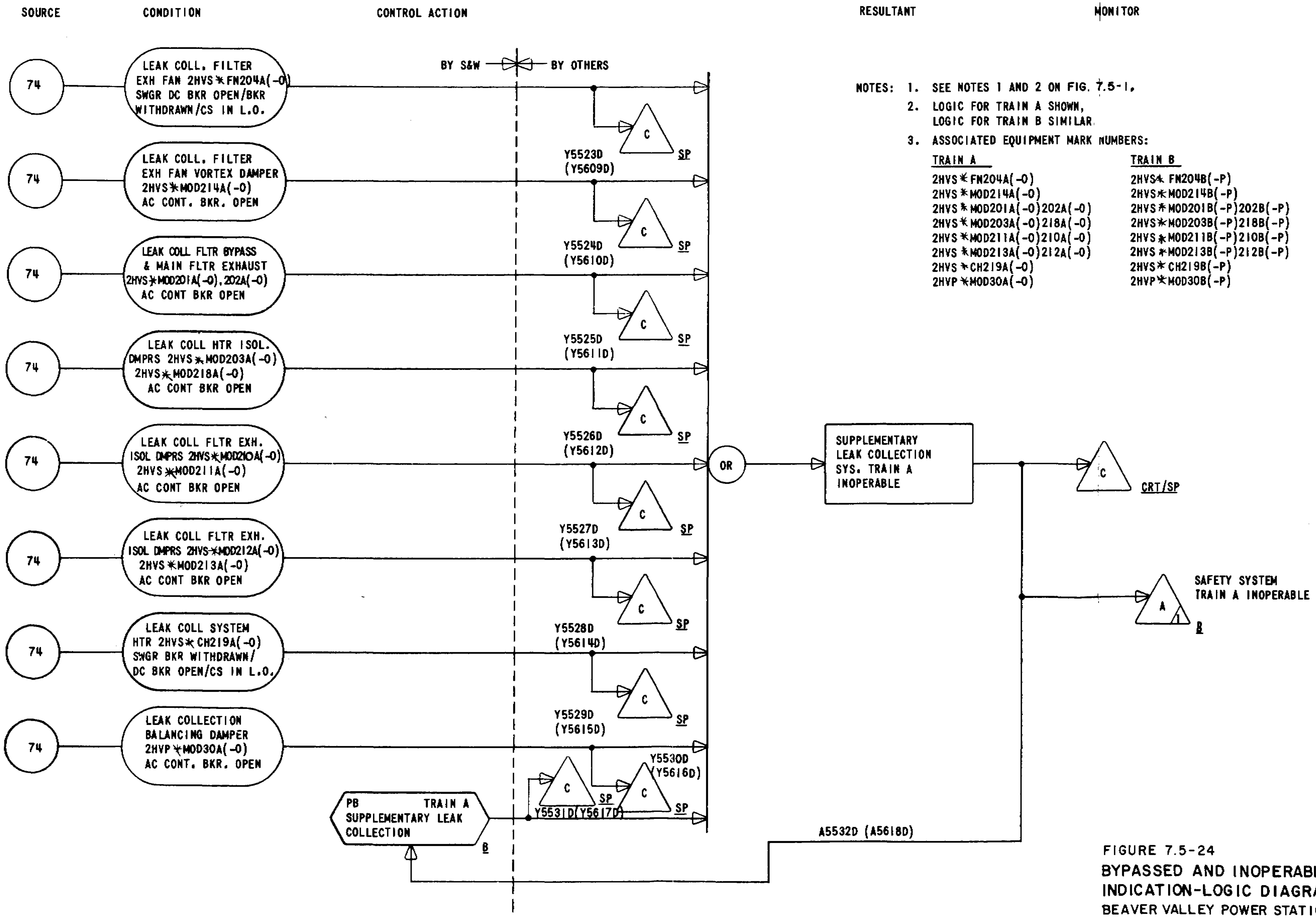
FIGURE 7.5-22
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2SWS*MOV148A(-O)	2SWS*MOV148B(-P)
2HVR*ACU208A(-O)	2HVR*ACU208B(-P)
2HVR*MOD26A(-O)27A(-O)	2HVR*MOD26B(-P)27B(-P)

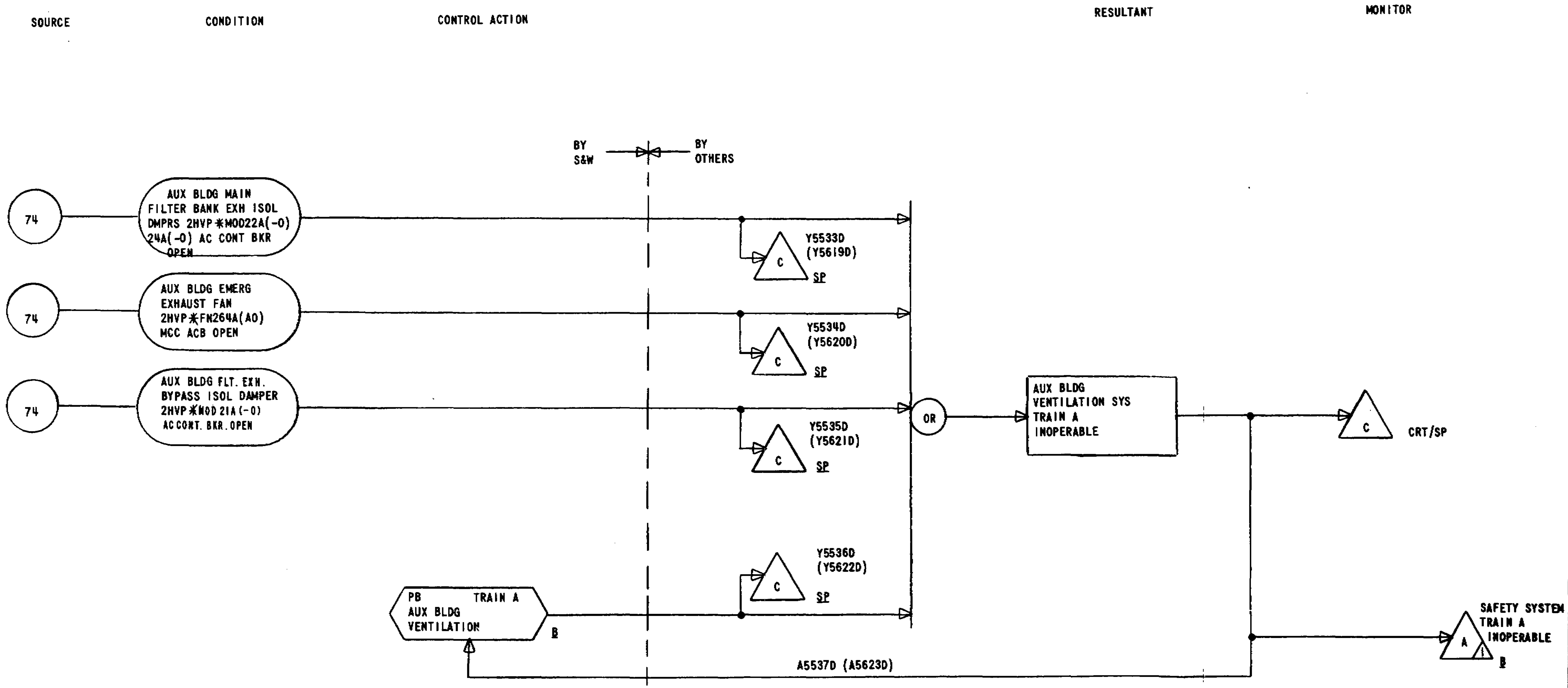
FIGURE 7.5-23
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:
1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVS*FN204A(-0)	2HVS*FN204B(-P)
2HVS*MOD214A(-0)	2HVS*MOD214B(-P)
2HVS*MOD201A(-0)202A(-0)	2HVS*MOD201B(-P)202B(-P)
2HVS*MOD203A(-0)218A(-0)	2HVS*MOD203B(-P)218B(-P)
2HVS*MOD211A(-0)210A(-0)	2HVS*MOD211B(-P)210B(-P)
2HVS*MOD213A(-0)212A(-0)	2HVS*MOD213B(-P)212B(-P)
2HVS*CH219A(-0)	2HVS*CH219B(-P)
2HVP*MOD30A(-0)	2HVP*MOD30B(-P)

FIGURE 7.5-24
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

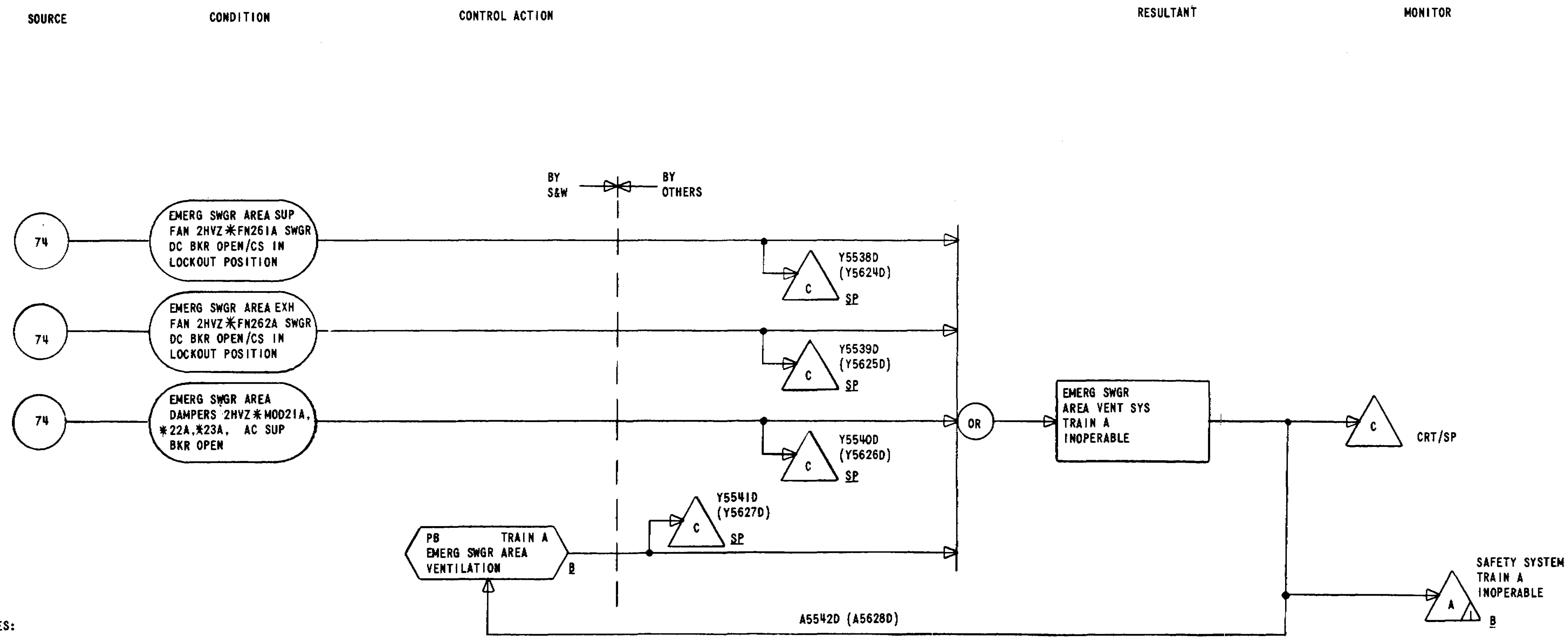


NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVP*MOD22A(-O)24A(-O)	2HVP*MOD22B(-P)24B(-P)
2HVP*MOD21A(-O)	2HVP*MOD21B(-P)
2HVP*FN264A(AO)	2HVP*FN264B(BP)

FIGURE 7.5-25
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

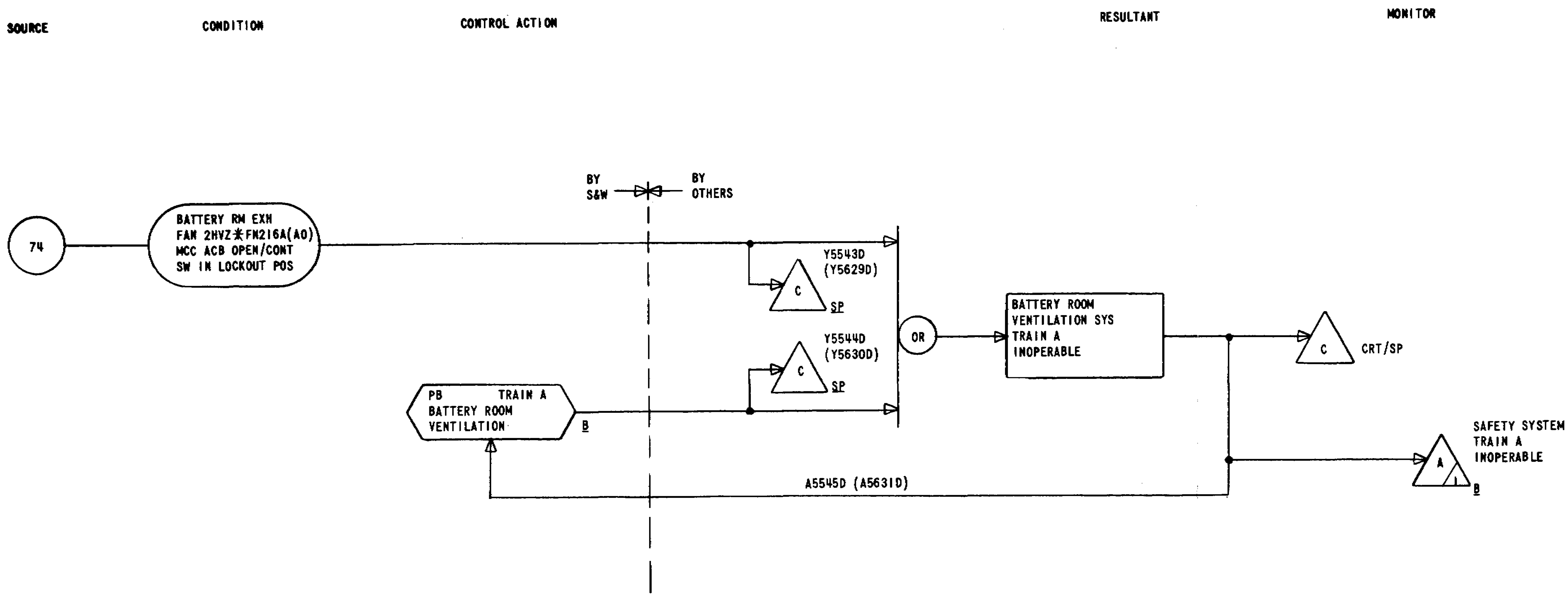


NOTES:

1. SEE NOTES 1 AND 2 ON FIG.7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVZ*FN261A(-0)	2HVZ*FN261B(-P)
2HVZ*FN262A(-0)	2HVZ*FN262B(-P)
2HVZ*MOD21A(-0)22A(-0)23A(-0)	2HVZ*MOD21B(-P)22B(-P)23B(-P)

FIGURE 7.5-26
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

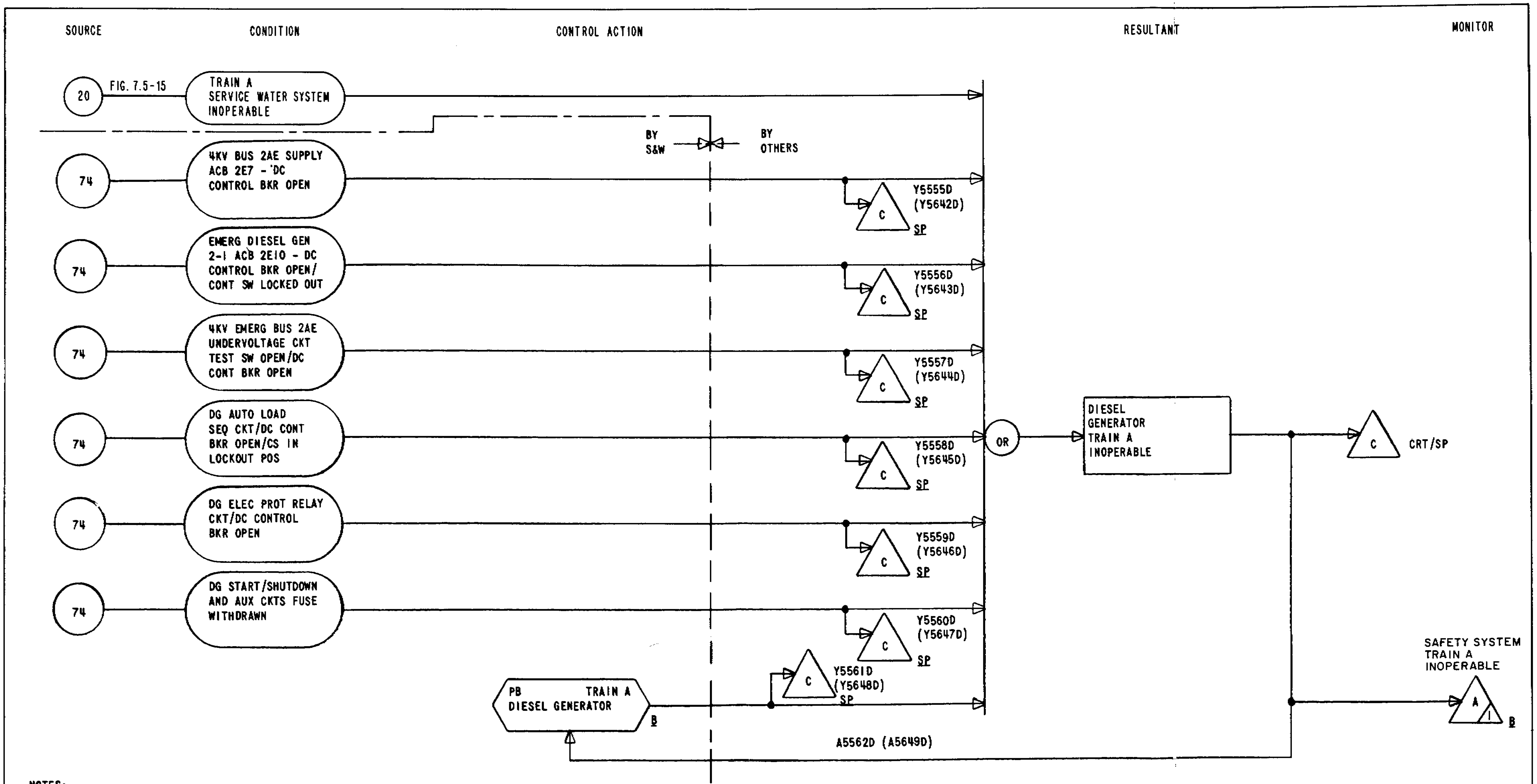


NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVZ*FN216A(AO)	2HVZ*FN216B(BP)

FIGURE 7.5-27
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

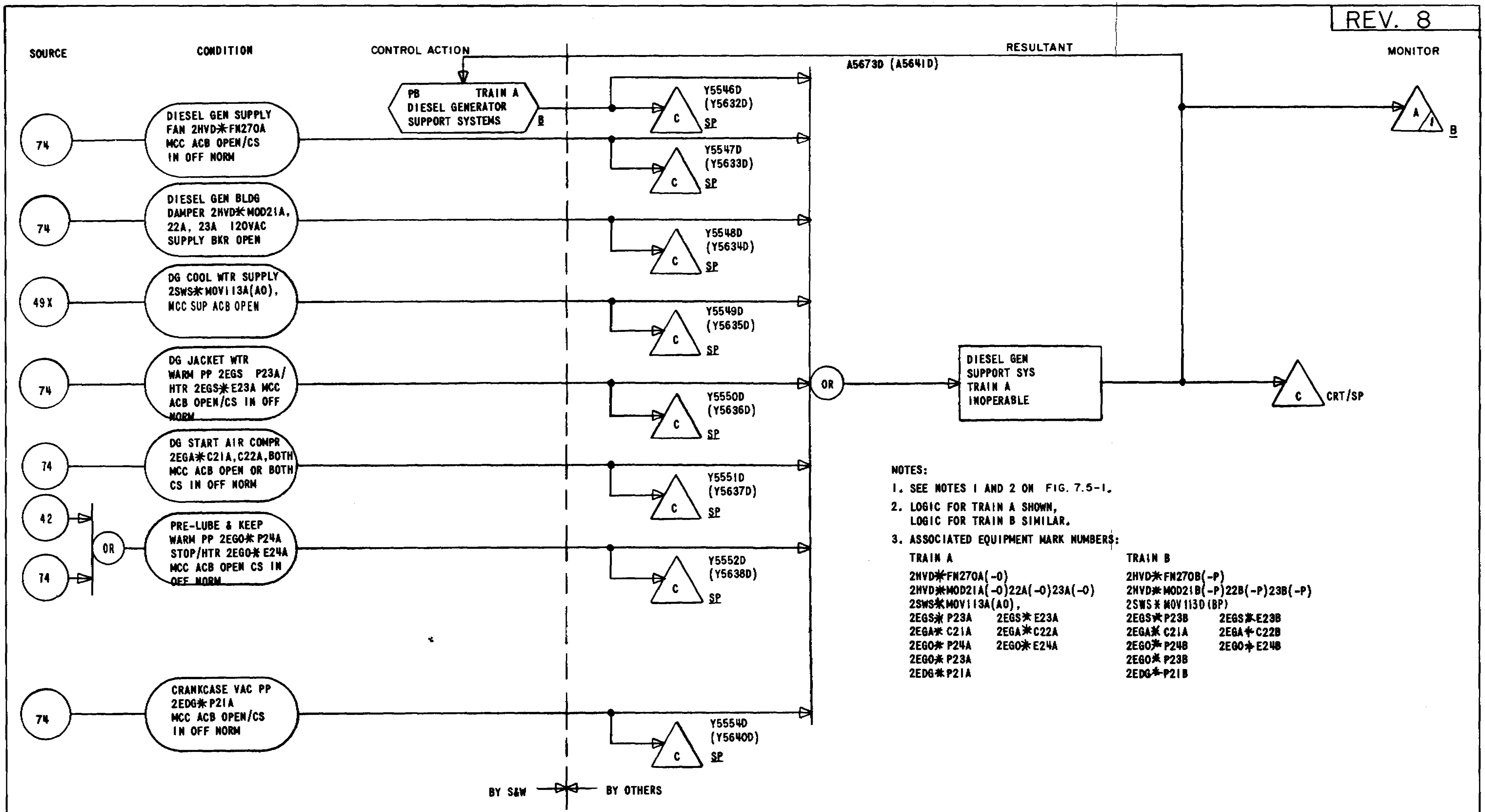


NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
ACB2E7	ACB2F7
ACB2E10	ACB2F10
BUS2AE	BUS2DF
DIESEL GENERATOR 2-1	DIESEL GENERATOR 2-2

FIGURE 7.5-28
BYPASSED AND INOPERABLE STATUS INDICATION - LOGIC DIAGRAM
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

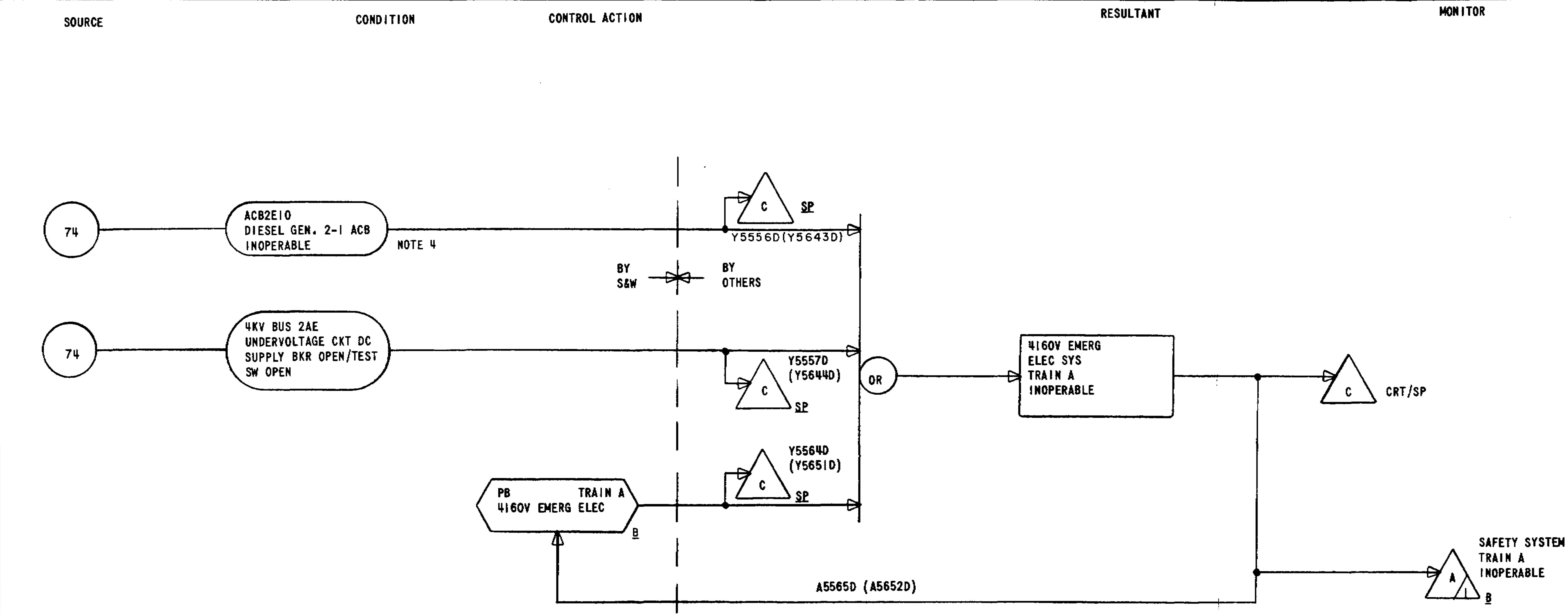


NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A		TRAIN B	
2HVD*FN270A(-O)		2HVD*FN270B(-P)	
2HVD*MOD21A(-O)22A(-O)23A(-O)		2HVD*MOD21B(-P)22B(-P)23B(-P)	
2SWS*MOV113A(AO),		2SWS*MOV113D(BP)	
2EGS*P23A	2EGS*E23A	2EGS*P23B	2EGS*E23B
2EGA*C21A	2EGA*C22A	2EGA*C21A	2EGA*C22B
2EGO*P24A	2EGO*E24A	2EGO*P24B	2EGO*E24B
2EGO*P23A		2EGO*P23B	
2EDG*P21A		2EDG*P21B	

FIGURE 7.5-29
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



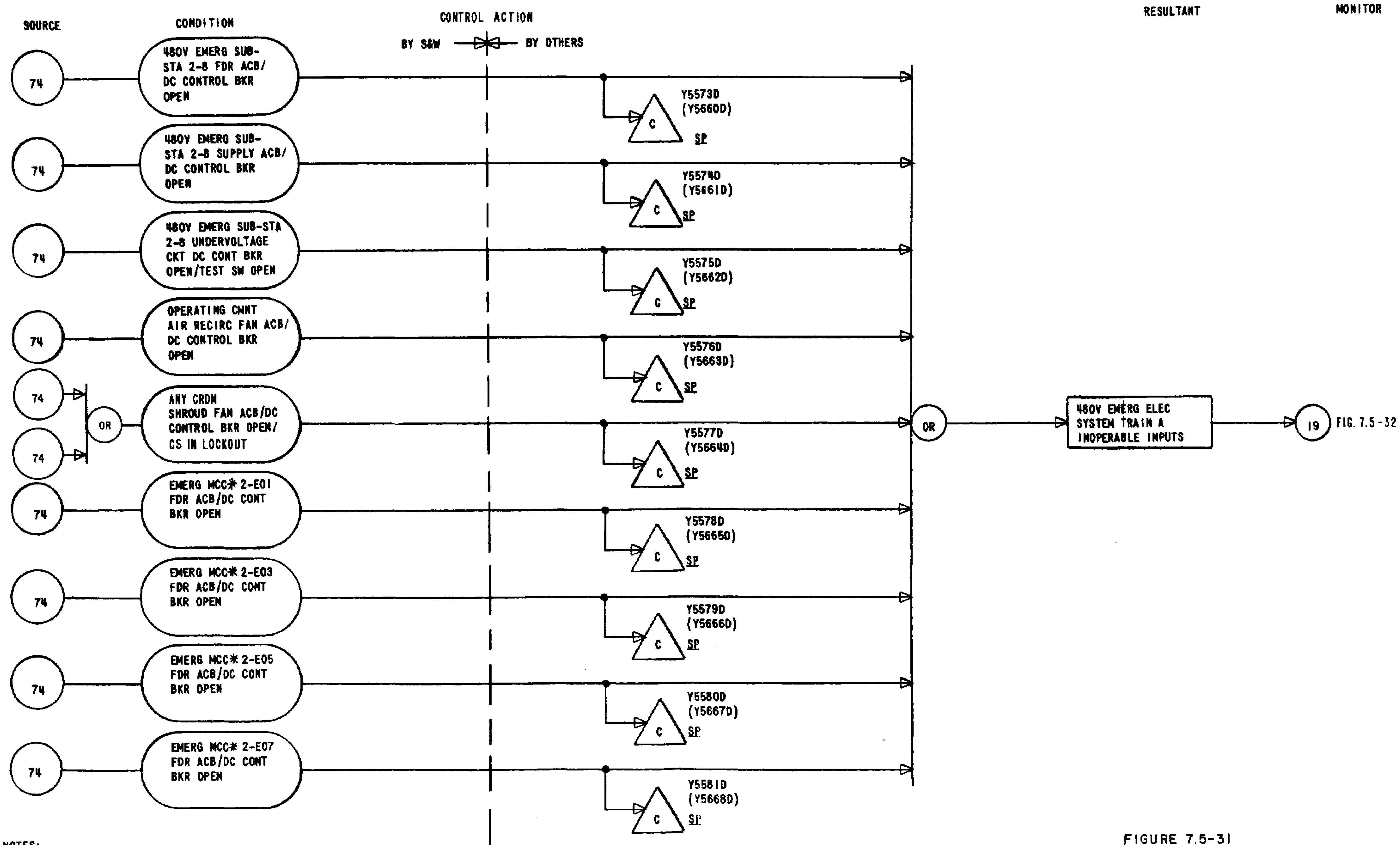
NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
BUS 2AE	BUS 2DF
ACB 2E10	ACB 2F10

4. LOSS OF BREAKER CONTROL POWER, CONTROL SWITCH IN "PULL TO LOCKOUT", OR BREAKER RACKED OUT.

FIGURE 7.5-30
BYPASSED AND INOPERABLE STATUS
INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. SEE NOTES ON FIG. 7.5-32.

FIGURE 7.5-31
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

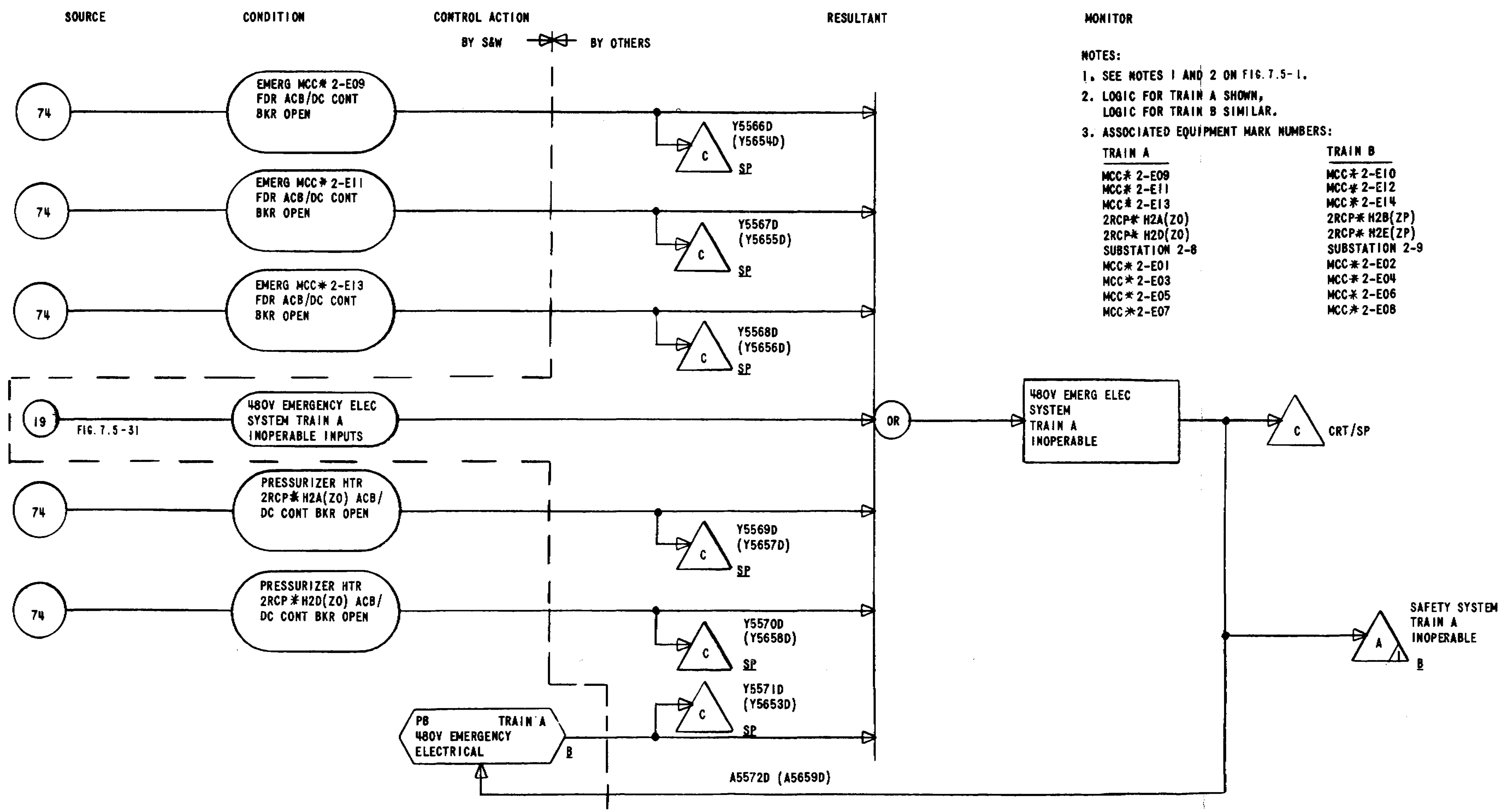
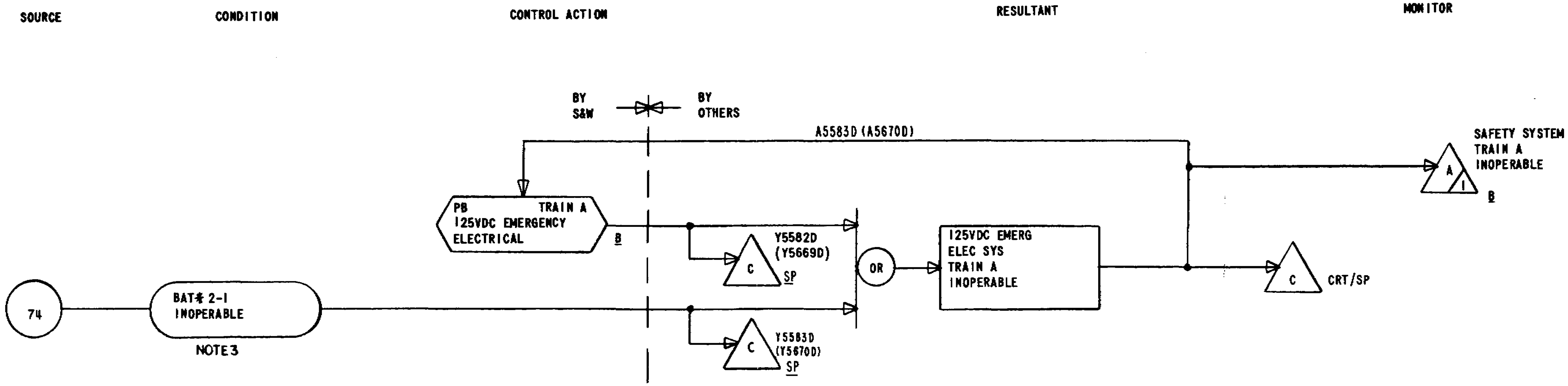


FIGURE 7.5-32
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

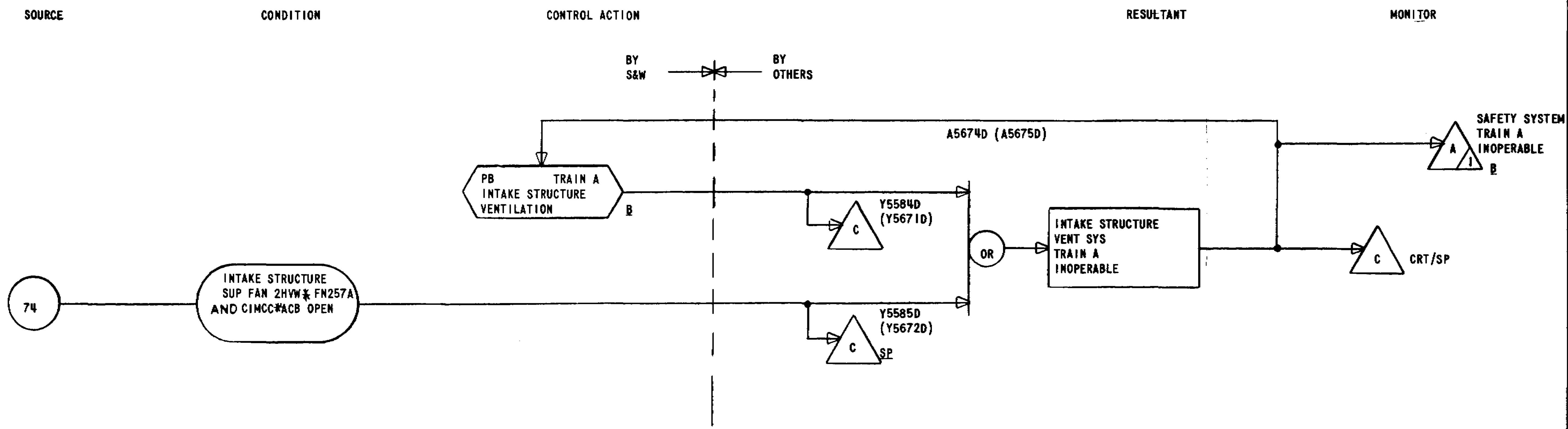


NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. OUTPUT IS PRESENT WHENEVER BREAKER IS TRIPPED OR RACKED OUT.
4. ASSOC. EQUIP. MARK NUMBERS:

TRAIN A	TRAIN B
BAT * 2-1	BAT * 2-2

FIGURE 7.5-33
BYPASSED AND INOPERABLE STATUS INDICATION-LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



NOTES:

1. SEE NOTES 1 AND 2 ON FIG. 7.5-1.
2. LOGIC FOR TRAIN A SHOWN, LOGIC FOR TRAIN B SIMILAR.
3. ASSOCIATED EQUIPMENT MARK NUMBERS:

TRAIN A	TRAIN B
2HVW* FN257A(-O),C1(-G)	2HVW* FN257B(-P),C2(-G)

FIGURE 7.5-34
BYPASSED AND INOPERABLE STATUS INDICATION - LOGIC DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.6 ALL OTHER SYSTEMS REQUIRED FOR SAFETY

7.6.1 Instrumentation and Control Power Supply System

7.6.1.1 Description

The following is a description of the instrumentation and control power supply system:

1. Figure 7.6-1 gives a single line diagram of the instrumentation and control power supply system.

2. There are four inverters and their associated distribution panels. Each inverter is connected independently to one or more distribution panels.

3. The inverters provide a source of 118 V 60 Hz power for the operation of the nuclear steam supply system instrumentation. This power is derived from the 480 V ac, three-phase, 60 Hz distribution system (preferred power supply), or the station batteries, which assure continued operation of instrumentation systems in the event of a station blackout.

4. Each of the four sets of distribution panels may be connected to a backup source of 120 V ac power. The tie is through a local electrically-operated manual bypass switch, which is mechanically interlocked with the breaker connecting the inverter to the distribution panel such that the distribution panels cannot be connected to both sources simultaneously.

7.6.1.2 Analysis

There are two independent 480 V ac power sources, each serving two inverters. Loss of either 480 V ac power source affects only two of the four inverters.

There are four independent batteries. Each of the batteries are supplied with independent battery chargers.

Since not more than two inverters are connected to the same bus, a loss of a single bus can only affect two of the four inverters.

Each inverter is independently connected to its respective vital bus distribution panels so that loss of an inverter cannot affect more than one of the four sets of vital bus distribution panels.

Each of the four sets of vital bus distribution panels is connected to a backup 120 V ac power source. Each panel can receive power from the 120 V ac backup source under administrative control.

The manual bypass switch is interlocked to prevent paralleling of the inverters with the backup source.

No single failure in the instrument and control power supply system or its associated power supplies can cause a loss of power to more than one redundant load.

The inverters are designed to maintain their outputs within acceptable limits. The loss of the ac or dc inputs is alarmed in the main control room, as is the loss of an inverter output. There are no inverter breaker controls on the control board, as no manual transfers are necessary in the event of loss of the 480 V ac preferred power source.

Physical separation and provisions to protect against fire are discussed in Chapter 8.

The criteria applicable to the instrumentation and controls power supply system are based on the scope definitions presented in the Institute of Electrical and Electronics Engineers (IEEE) Standard 308-1974. The design is in compliance with IEEE Standard 308-1974 and Regulatory Guide 1.6. Availability of this system is continuously indicated by the operational status of the systems it serves (Figure 7.6-1) and is verified by periodic testing performed on the served systems. The inverters are seismically qualified in accordance with the qualification program described in Section 3.10.

7.6.2 Residual Heat Removal Isolation Valves

7.6.2.1 Description

The residual heat removal (RHR) system isolation valves are normally closed and are only opened for RHR after system pressure is reduced to approximately 360 psig and system temperature has been reduced to approximately 350°F. They are the same type of valve and motor operator as those used for accumulator isolation, but they differ in their controls and in their indications in the following respect:

The RHR valves are provided with control switches that have red (open) and green (closed) position indicating lights located on the main control board and emergency shutdown panel (ESP). These lights are powered by valve control power and actuated by valve motor operator limit switches.

There are two motor-operated valves (MOVs) in series in each of the two RHR pump suction lines from the reactor coolant system (RCS) hot legs, and one MOV in each of the two RHR discharge lines. The two valves nearest the RCS (702A&B) are designated as the inner isolation valves, while the two valves nearest the RHR pumps (701A&B) are designated as the outer isolation valves. The valves in the discharge line are designated 720A&B. The interlock functions, provided for the outer isolation valves and discharge valve 720A shown on Figure 7.6-2, are identical (though derived from a diverse transmitter) to those provided for the inner isolation valves and discharge valve 720B shown on Figure 7.6-3.

Each valve is interlocked so that it cannot be opened unless the RCS pressure is below approximately 360 psig. This interlock prevents the valve from being opened when the RCS pressure plus the RHR pump pressure would be above the RHR system design pressure. A second pressure interlock is provided to close the valve automatically if the RCS pressure subsequently increases to above approximately 700 psig. The pressure functions shown on Figure 7.6-3 are derived from a pressure transmitter designated PT441, which is supplied from a different vendor than the transmitter designated PT440 from which the pressure functions shown on Figure 7.6-2 are derived. This is the method used to achieve diversity. The autoclosure interlock may be manually defeated during normal RHR operation to prevent inadvertent RHR isolation valve closure.

All four MOVs in the RHR suction lines are powered from Class 1E power sources. Two of the four MOVs (one in each suction line) are powered from two separate Class 1E power sources. This redundancy assures that the suction line to the RHR pump can be isolated when RCS pressure is above the preset value. In order to ensure that an RHR pump is available when required and one of the redundant power sources is not available, provisions are made to transfer power to the other Class 1E redundant power source. This will allow opening of the two series valves in one of the RHR pump suction lines.

Interlocks are provided to prevent paralleling of the two Class 1E power sources.

7.6.2.2 Analysis

Based on the scope definitions presented in the IEEE Standards 279-1971 and 308-1974, these criteria do not apply to the RHR isolation valve interlocks. However, in order to meet the U.S. Nuclear Regulatory Commission (USNRC) requirements and because of the possible severity of the consequences of loss of function, the following requirements of IEEE Standard 279-1971 apply to this circuit:

1. For the purpose of applying IEEE Standard 279-1971 to this circuit, the following-definitions will be used:

    a. Protection system

        The two valves in series in each line and all components of their interlocking and closure circuits.

    b. Protective action

        The automatic initiation and maintenance of RHR system isolation from the RCS pressures above the preset value.

2. Paragraph 4.10 of IEEE Standard 279-1971: The preceding pressure interlock signals and logic will be tested on-line to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the output relay (which provides the final output signal to the valve control circuit) by observing that the armature of the output relay has changed state. (Test does not include provisions available from safeguard test cabinet.) This is done in the best interests of safety since an actual actuation (opening) of

the valve could potentially leave only one remaining valve to isolate the low pressure RHR system from the RCS.

3. Paragraph 4.15 of IEEE Standard 279-1971: This requirement does not apply, as the set points are independent of the mode of the operation and are not changed.

Environmental qualification of the valves and wiring is discussed in Section 3.11.

7.6.3 Refueling Interlocks

Electrical interlocks (limit switches), as discussed in Section 9.1.3, are provided for minimizing the possibility of damage to the fuel during fuel handling operations.

7.6.4 Accumulator Motor-Operated Valves

The design of the interconnecting of these signals to the accumulator isolation valve meets the following criteria established in previous USNRC positions on this matter:

1. Automatic opening of the accumulator valves when, a) the primary coolant system pressure exceeds a preselected value (to be specified in the Technical Specifications), or b) a safety injection (SI) signal has been initiated. Both signals shall be provided to the valves.

2. Utilization of an SI signal to automatically remove (override) any bypass features that are provided to allow an isolation valve to be closed for short periods of time when the RCS is at pressure (in accordance with the provisions of the proposed Technical Specifications). As a result of the confirmatory SI signal, isolation of an accumulator with the reactor at pressure is acceptable.

The control circuit for these valves is shown on Figure 7.6-4. The valves and control circuits are further discussed in Sections 6.3.2 and 6.3.5.

The SI system accumulator discharge isolation MOVs are normally open valves which are controlled from the main control board and the ESP. These valves are interlocked such that:

1. They open automatically on receipt of an SI signal with the main control board switch in either the auto or close position.

2. They open automatically whenever the RCS pressure is above the SI unblock pressure (P-11) specified in the Technical Specifications only when the main control board switch is in the auto position.

3. They cannot be closed as long as an SI signal is present.

4. Power to valves is removed during normal plant operation to prevent inadvertent or spurious closure of the valves.

The three main control board and ESP control switches for these valves provide a spring return to auto from the open position and a maintain position in close.

The maintain closed position is required to provide an administratively controlled manual block of the automatic opening of the valve at pressure above the SI unblock pressure (P-11]. The manual block or maintain closed position is required when performing periodic check valve leakage test when reactor is at pressure. The maximum permissible time that an accumulator valve can be closed when the reactor is at pressure is specified in the Technical Specifications.

Administrative control is required to ensure that any accumulator valve, which has been closed at pressures above the SI unblock pressure, is returned to the auto position. Verification that the valve automatically returns to its normal full open position would also be required.

During Beaver Valley Power Station - Unit 2 (BVPS-2) shutdown, the accumulator valves are in a closed position. To prevent an inadvertent opening of these valves during that period, the accumulator valve breakers should be opened or removed. Administrative control is again required to ensure that these valve breakers are closed during the prestart-up procedures.

These normally open MOVs have alarms to indicate a malpositioning (with regard to their emergency core cooling system (ECCS) function during the injection phase). The alarms sound in the main control room.

An alarm will sound for either accumulator isolation valve under the following conditions when the RCS pressure is above the SI unblocking pressure:

1. Valve stem limit switch indicates valve not open,

2. Valve motor operator limit switch indicates valve not open. The alarms on this switch will repeat themselves at given intervals.

7.6.5 Switchover from Injection to Recirculation

During the initial injection phase following an accident, the refueling water storage tank (RWST) is used to supply borated water to the ECCS pumps. The changeover from the injection to the recirculation mode is initiated automatically. Protection logic is provided to automatically open the low head safety injection (LHSI) recirculation supply isolation valves when the RWST water level reaches a predetermined extreme low level set point, in conjunction with the initiation of the SI engineered safety features actuation signals, and automatic switchover will be as follows:

1. The RWST 2/4 extreme low level coupled with a latched-in SI signal will automatically open valves 8811A/B (Figure 7.6-8,

Sheets 1, 2, 3, 4, 5) connecting the recirculation pump discharge to the LHSI pump discharge lines. When valves 8811A/B are full open, the associated LHSI pump will be tripped (Figure 7.6-8, Sheet 3 shows pump tripping).

2. Similarly, the LHSI header cross-connect valves 8887A/B (Figure 7.6-8, Sheet 4) will be automatically closed and valves 8812A/B (Figure 7.6-8, Sheet 5) supplying the suction of the charging/safety injection system will be automatically opened provided 8811A/B are fully open.

In the event that a SI signal is generated, these interlocks provide for the retention of that signal by latching relays. The retention of this signal is required since the emergency procedures would instruct the operator to reset the safeguards actuation signal at a time significantly in advance of the RWST low level setpoint signal generation.

The details of achieving cold leg recirculation following SI are given in Section 6.3.2 and Table 6.3-7. Figure 7.6-8, Sheet 2, shows the logic which is used to automatically open the sump valves.

7.6.6 Reactor Coolant System Loop Isolation Valve Interlocks Description

The purpose of these interlocks is to ensure that an accidental start-up of an unborated and/or cold, isolated reactor coolant loop results only in a relatively slow reactivity insertion rate.

The interlocks (refer to Figure 7.2-1, Sheet 16, for interlock logic functions) are required to perform a protective function. Therefore, there are:

1. A limit switch to indicate that a valve is fully open.

2. A limit switch to indicate that a valve is fully closed.

3. Two differential pressure switches in each line which bypasses a cold leg loop isolation valve. This is the line which contains the relief line isolation valve. It should be noted that flow through the relief line isolation valves indicates that: 1) the valves in the line are open, 2) the line is not blocked, and 3) the pump is running.

7.6.7 Interlocks for RCS Pressure Control During Low Temperature Operation

The basic function of the RCS pressure control during low temperature operation is discussed in Section 5.2.2. This pressure control includes semi-automatic actuation logic for two (of the three) pressurizer power-operated relief valves (PORVs). The function of this actuation logic is to continuously monitor RCS temperature and pressure conditions, with actuation logic armed by operator action by means of an arm/block main control board switch which is placed in the block position when BVPS-2 is at operating pressure. The monitored system temperature signals are processed to generate the reference pressure limit, which is compared to the actual monitored RCS pressure. This comparison will provide an actuation signal to an actuation device which, if manually armed, will cause the PORV to automatically open, as necessary, to prevent pressure conditions from exceeding allowable limits. Refer to Figure 7.2-1, Sheets 17 and 18, for the diagrams showing the basic elements used to process the generating station variables for this low temperature RCS overpressurization preventive interlocks. Sheets 7.2-1, Sheets 17 and 18 are the functional diagrams for PORV and block valves overpressurization preventive interlocks. 7.2-1, Sheets 17 and 18 are the functional diagrams for PORV and block valves interlocks for the pressurizer pressure relief (PPR) system for Trains A and B.

The generating station variables required for this interlock are channelized and train-assigned as indicated on Figure 7.2-1, Sheets 17 and 18.

The wide range temperature signals are used as input to generate the reference pressure limit program considering BVPS-2's allowable pressure and temperature limits. This reference pressure is then compared to the actual RCS pressure monitored by the wide range pressure channel. The error signals derived from the difference between the reference pressure and the measured pressure will first annunciate a main control board alarm whenever the measured pressure approaches, within a predetermined amount, the reference pressure. On a further increase in measured pressure, the error signal will generate an annunciated actuation signal. Channel and train independence between protection sets, and between protection sets and between Trains A and B, is maintained from sensors to the PORVs.

Upon receipt of the actuation signal, the actuation device will automatically cause the PORV to open. Upon sufficient RCS inventory letdown, the operating RCS pressure will decrease, clearing the actuation signal. Removal of this signal from the actuation device causes the PORV to close.

7.6.7.1 Analysis of Interlock

The logic function and actuation signals shown on 7.2-1, Sheets 17 and 18 are processed in the elements of the protection system. For the criteria to which this system is designed, refer to Sections 7.2 and 7.3. The primary purpose of these interlocks is automatic transient mitigation. These interlocks do not perform a protective function but rather provide semi-automatic pressure control at low temperatures as a backup to the operator. However, to assure a well-engineered design and improved operability, the low instrumentation and control (I&C) portions of the interlocks for RCS pressure control during low temperature operation will satisfy applicable sections of USNRC Branch Technical Position RSB 5-2 that address I&C.

7.6.7.2 Pressurizer Pressure Relief System

The interlocks described in Section 7.6.7, together with pressurizer pressure control shown on Figure 7.2-1, Sheet 11, and the interlocks for the pressurizer block valves A and B, shown on Figure 7.2-1, Sheets 17 and 18, are referred to as the PPR system.

The PPR system provides the following:

1. Capability for RCS overpressure mitigation during cold shutdown, heatup, and cooldown operations to minimize the potential for impairing reactor vessel integrity when operating at or near the vessel ductility limits and the system is manually armed.

2. Capability for RCS depressurization following Condition II, III, and IV events.

3. An interlock that, with the pressurizer PORVs and PORV block valves in auto control, closes the PORV block valves and prevents spurious signals from the PPR control system from inadvertently opening the PORVs when pressurizer pressure is low and the system in not manually armed.

7.6.7.3 Description of PPR System Interlock

Interlocks for the PPR system control the opening and closing of the pressurizer PORVs and the PORV block valves. These interlocks provide the following functions:

1. Pressurizer pressure control,

2. RCS pressure control during low temperature operation, and

3. RCS pressure control to achieve and maintain a cold shutdown and to heat up using equipment that is required for safety.

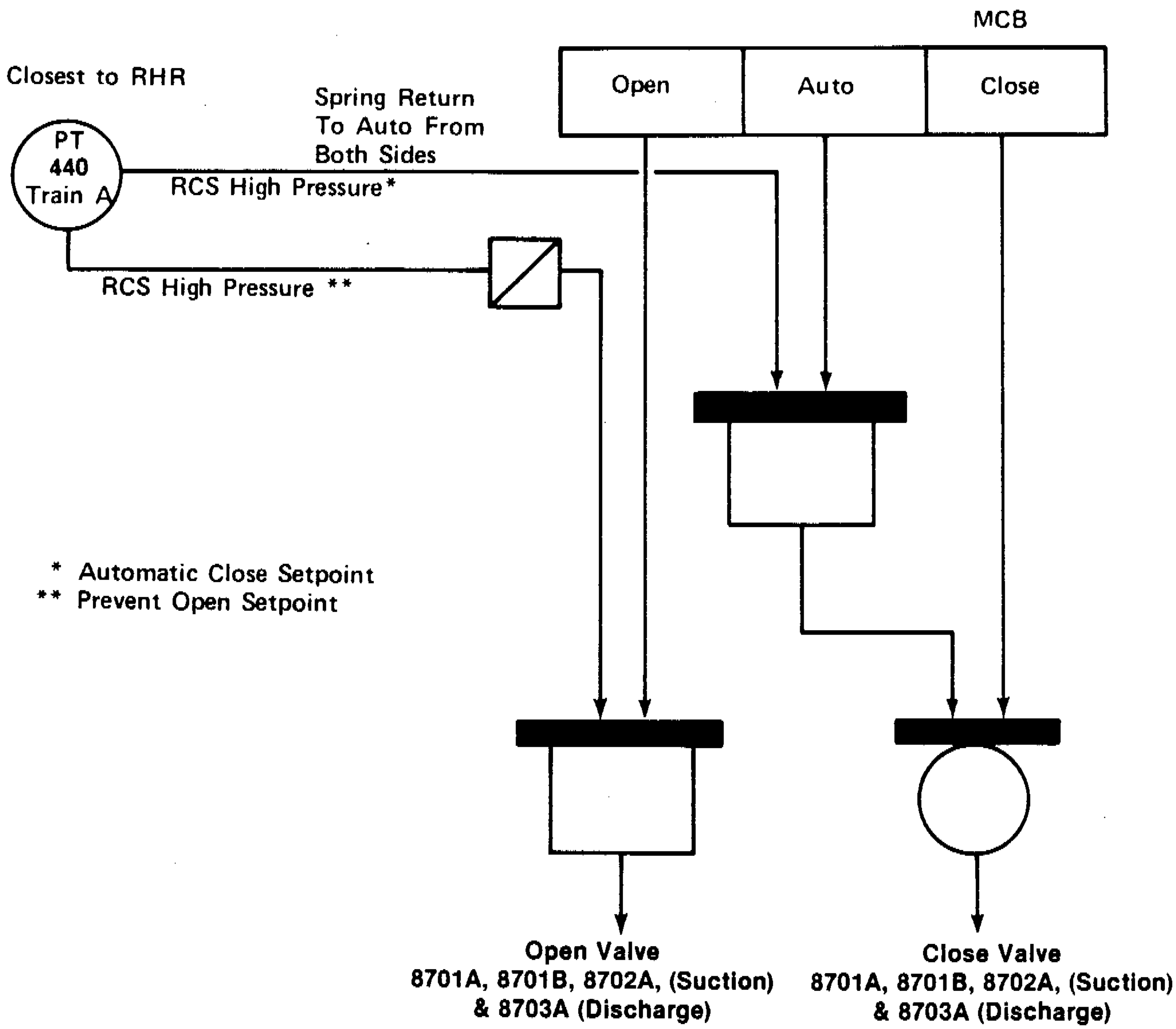
The interlock functions that provide pressurizer pressure control are derived from process parameters as shown on Figure 7.2-1, Sheets 6 and 11. The interlock logic functions as well as process parameter inputs required for low temperature operation are shown on Figure 7.2-1, Sheet 17 and 18. The functions include those needed for the PORV block valves as well as the pressurizer PORVs to meet both interlock logic and manual operation requirements where manual operation is at the main control board.

7.6.7.4 Service Water System Isolation Valves to the Turbine Plant Component Cooling Water Heat Exchangers

The service water system isolation valves to the turbine plant component cooling water heat exchangers (2SWS-MOV107A through D) perform the safety function of isolating the safety-related portion of the service water system from the nonsafety portion in the event of a CIA signal. This portion of the circuitry is designed to IEEE Standard 279-1971. Two service water system isolation valves (2SWS- MOV107A and D) also isolate the safety-related portion of the service water system from the nonsafety portion in the event of a service water low pressure signal. This portion of the circuit does not conform entirely to IEEE Standard 279-1971 in that the guidance of its Sections 4.10, 4.17, 4.19, and 4.20 are not met. Since this additional function (low pressure isolation) is not a signal "... that actuate(s) reactor trip ..." or a signal "... that, in the event of a serious reactor accident, actuate (s) engineered safeguards such as containment isolation…", conformance with IEEE Standard 279-1971 is not considered to be required. This portion of the circuit does, however, conform with IEEE Standard 279-1971 in areas other than those listed above.

REFER TO FIGURE 8.3-3

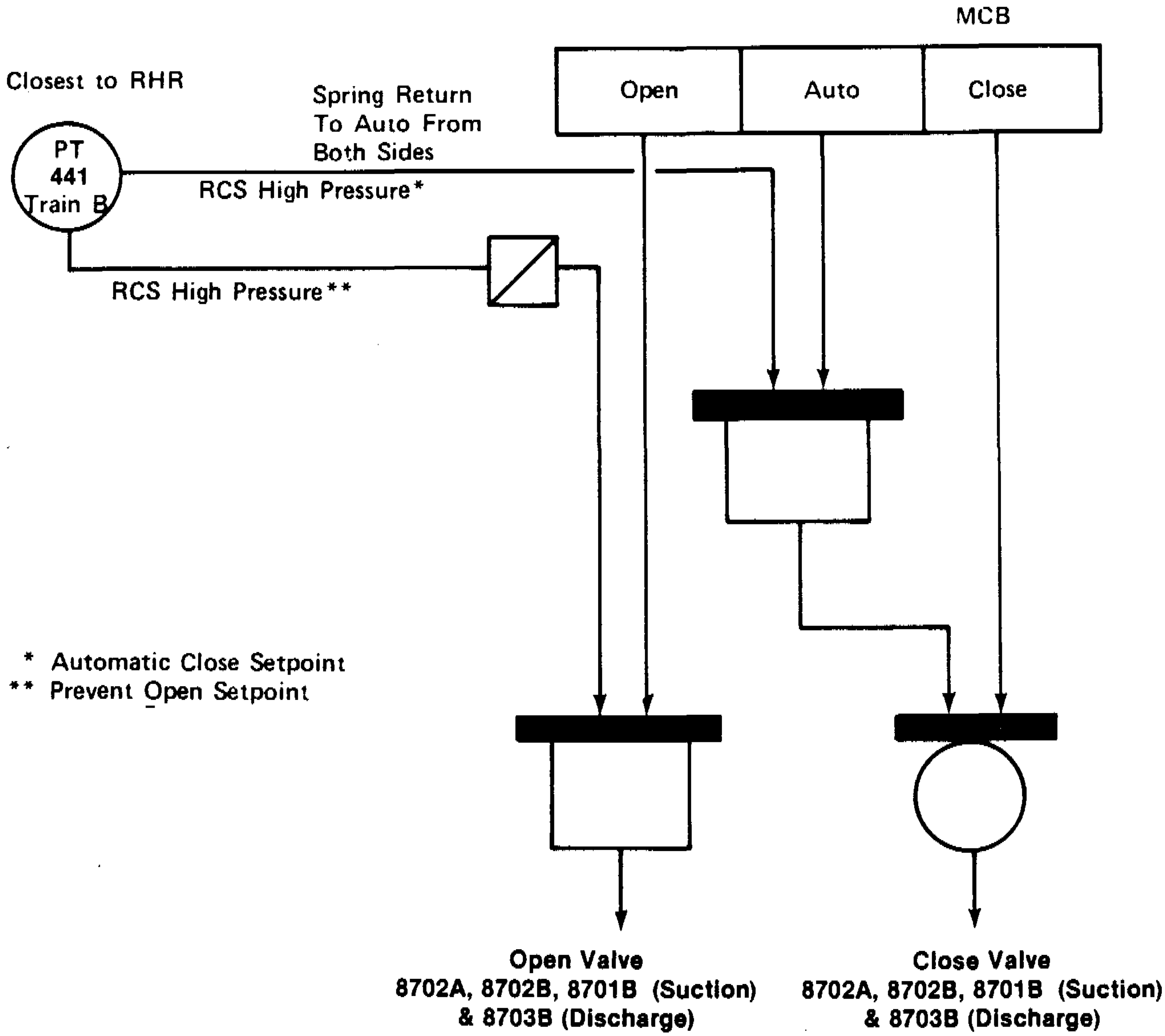
FIGURE 7.6-1
SINGLE LINE DIAGRAM OF
INSTRUMENTATION AND CONTROL
POWER SUPPLY SYSTEM
BEAVER VALLEY POWER STATION
UPDATED FINAL SAFETY ANALYSIS REPORT



Notes: Logic for Valves in Each Fluid System Train is Identical.
Valves 8701B and 8702A can be powered from either Train A or Train B.

SWEC VALVE NO.	(W) VALVE NO.
2RHS*MOV 701A	8701A
2RHS*MOV 701B	8701B
2RHS*MOV 702A	8702A
2RHS*MOV 702B	8702B
2RHS*MOV 720A	8703A
2RHS*MOV 720B	8703B

FIGURE 7.6-2
LOGIC DIAGRAM FOR OUTER RHR SUCTION ISOLATION VALVE AND DISCHARGE ISOLATION VALVE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



Notes: Logic for Valves in Each Fluid System Train is Identical.
Valves 8701B and 8702A can be powered from either Train A or Train B.

SWEC VALVE NO.	(W) VALVE NO.
2RHS*MOV 701A	8701A
2RHS*MOV 701B	8701B
2RHS*MOV 702A	8702A
2RHS*MOV 702B	8702B
2RHS*MOV 720A	8703A
2RHS*MOV 720B	8703B

FIGURE 7.6-3
LOGIC DIAGRAM FOR INNER RHR SUCTION ISOLATION VALVE AND DISCHARGE ISOLATION VALVE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

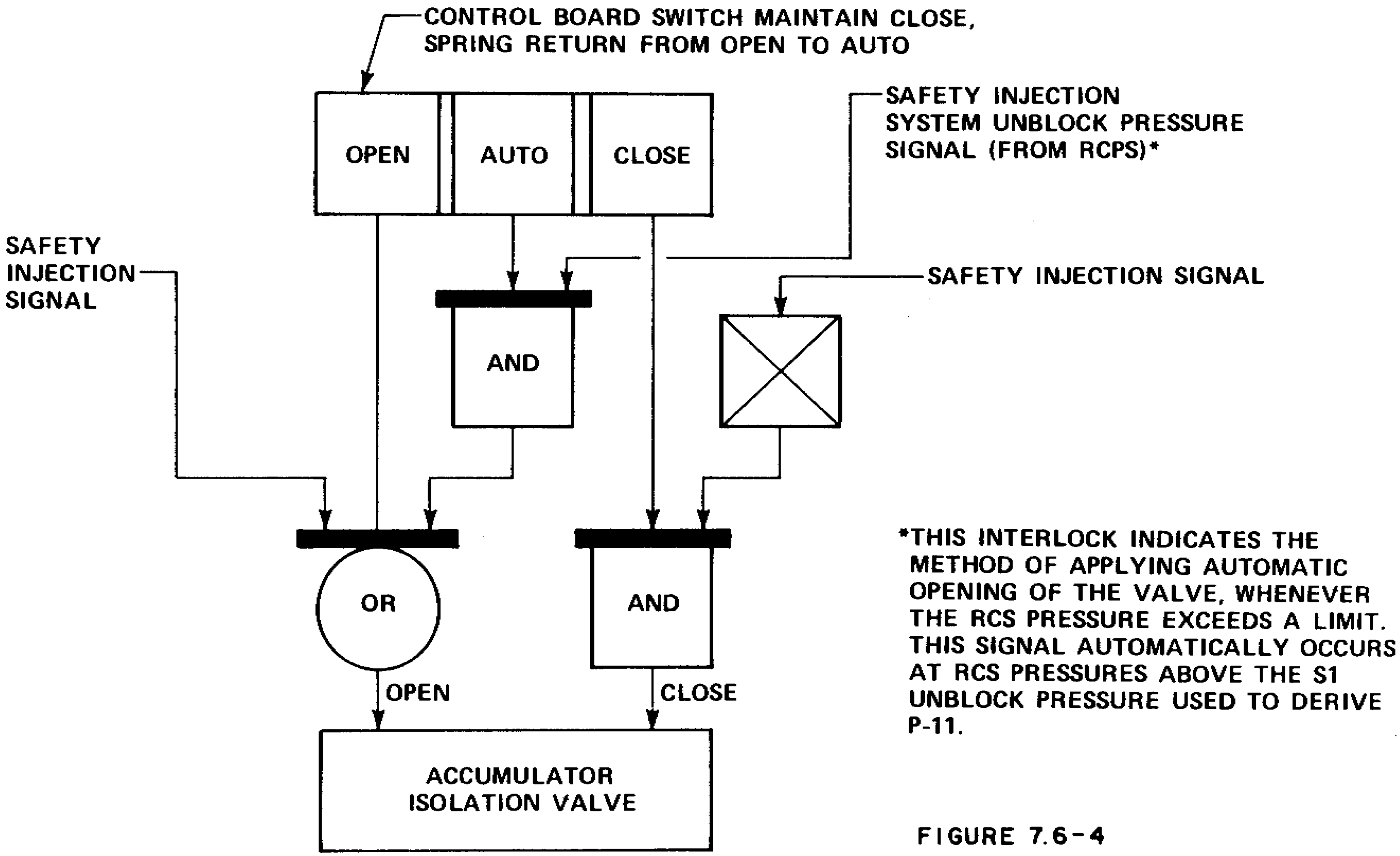
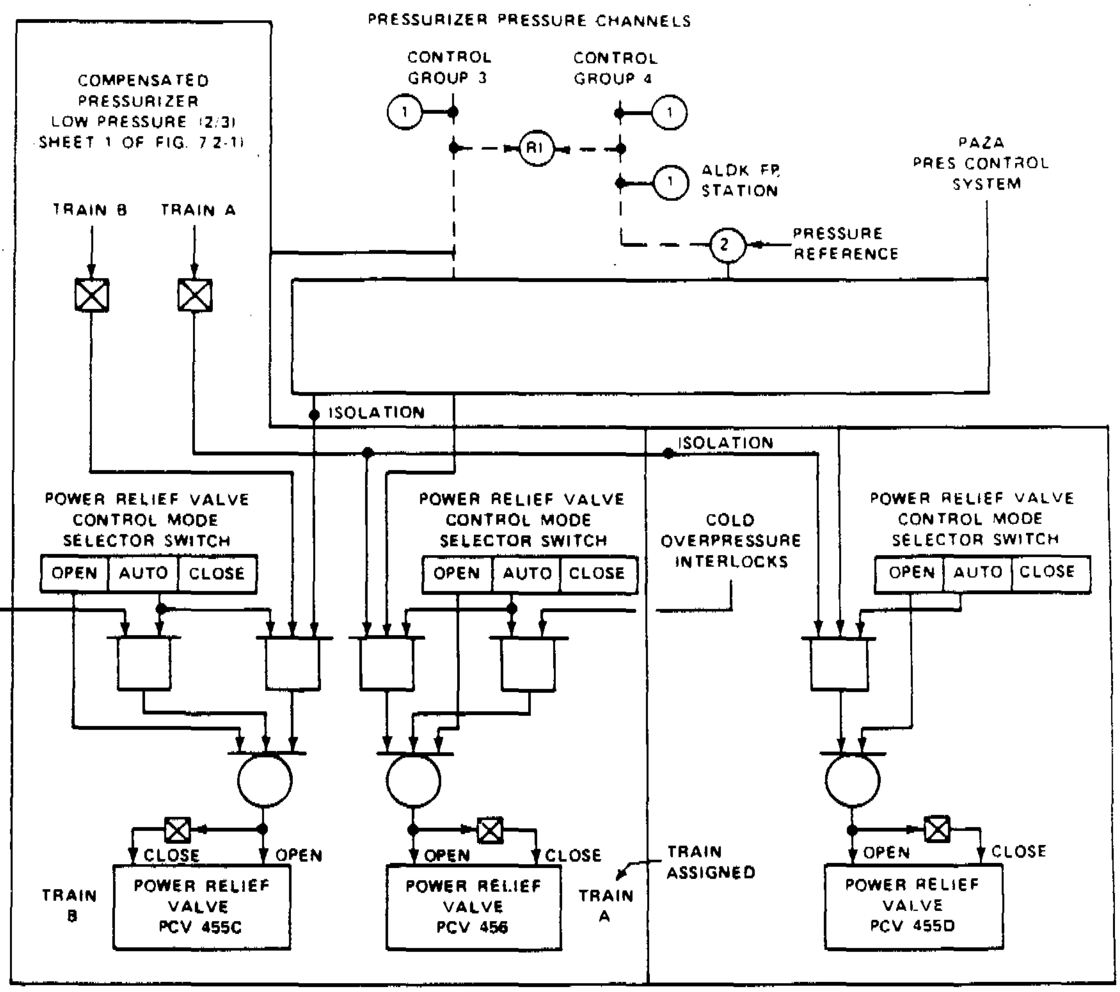


FIGURE 7.6-4
FUNCTIONAL BLOCK DIAGRAM OF ACCUMULATOR ISOLATION VALVE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



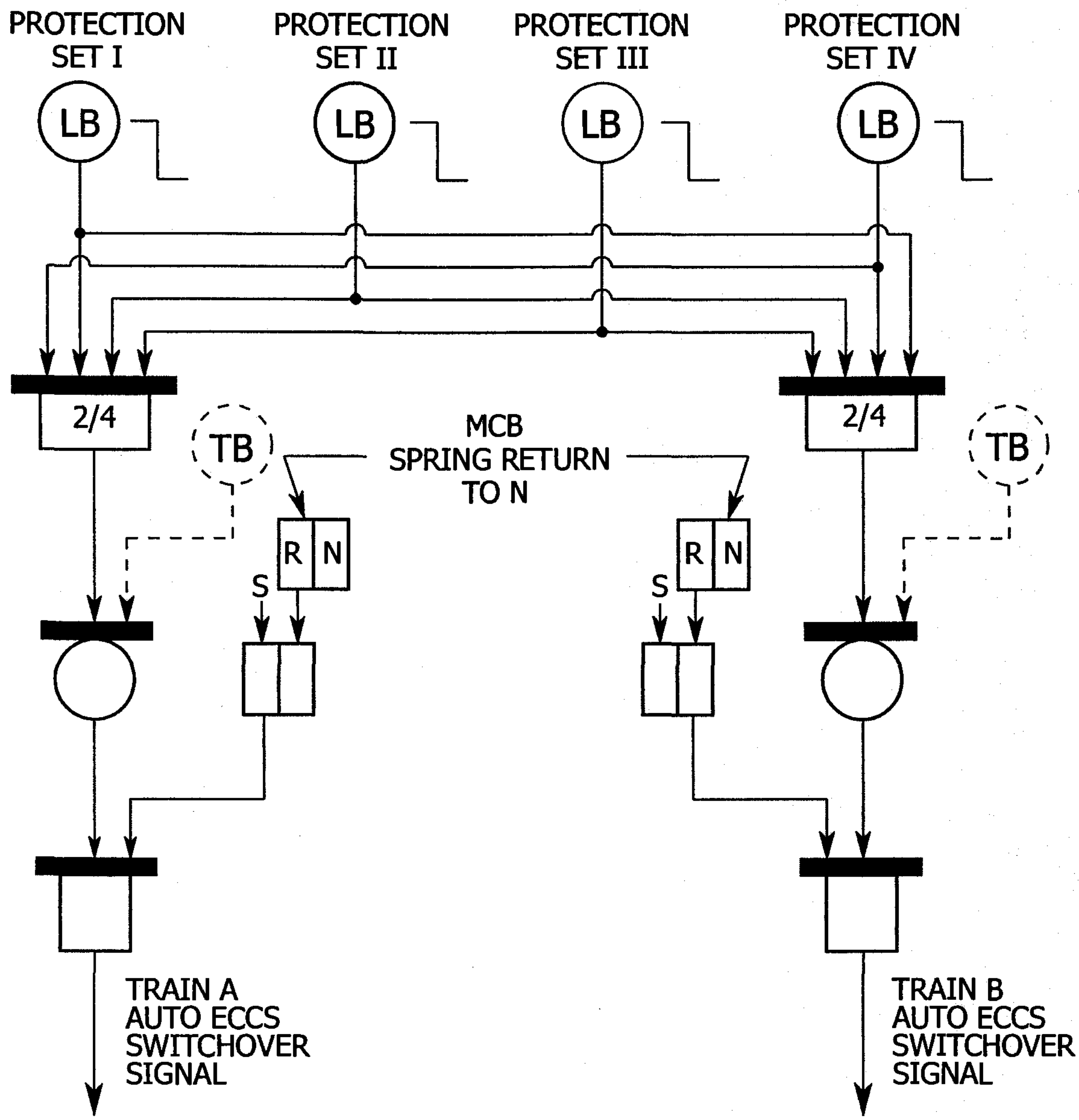
NOTE (1) THESE LOGIC FUNCTIONS DEPICT TYPICAL DESIGN. FOR FINAL LOGIC FUNCTIONS, INCLUDING INTERFACE WITH OTHER SYSTEMS AND COMPONENTS SUCH AS THE BLOCK VALVES, REFER TO FIG. 7.2-1 SHEETS 17 & 18.

PORV LOGIC FOR SAFETY GRADE COLD SHUTDOWN

FIGURE 7.6-7
FUNCTIONAL DIAGRAM FOR PORV INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 17

LB: RWST WATER EXTREME LOW LEVEL CHANNEL BISTABLES



- - -	PROPOSED BY W
S	SAFETY INJECTION SIGNAL
TB	RACK MOUNTED TEST BUTTON TWO PLACES - OPERATING EITHER SWITCH ALLOWS PARTIAL TRIP OF SEMI-AUTOMATIC ECCS SWITCHOVER

FIGURE 7.6-8 (SH. 1 OF 5)

LOGICAL DIAGRAM FOR SWITCHOVER FROM INJECTION TO RECIRCULATION AUTO ECCS SIGNAL

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

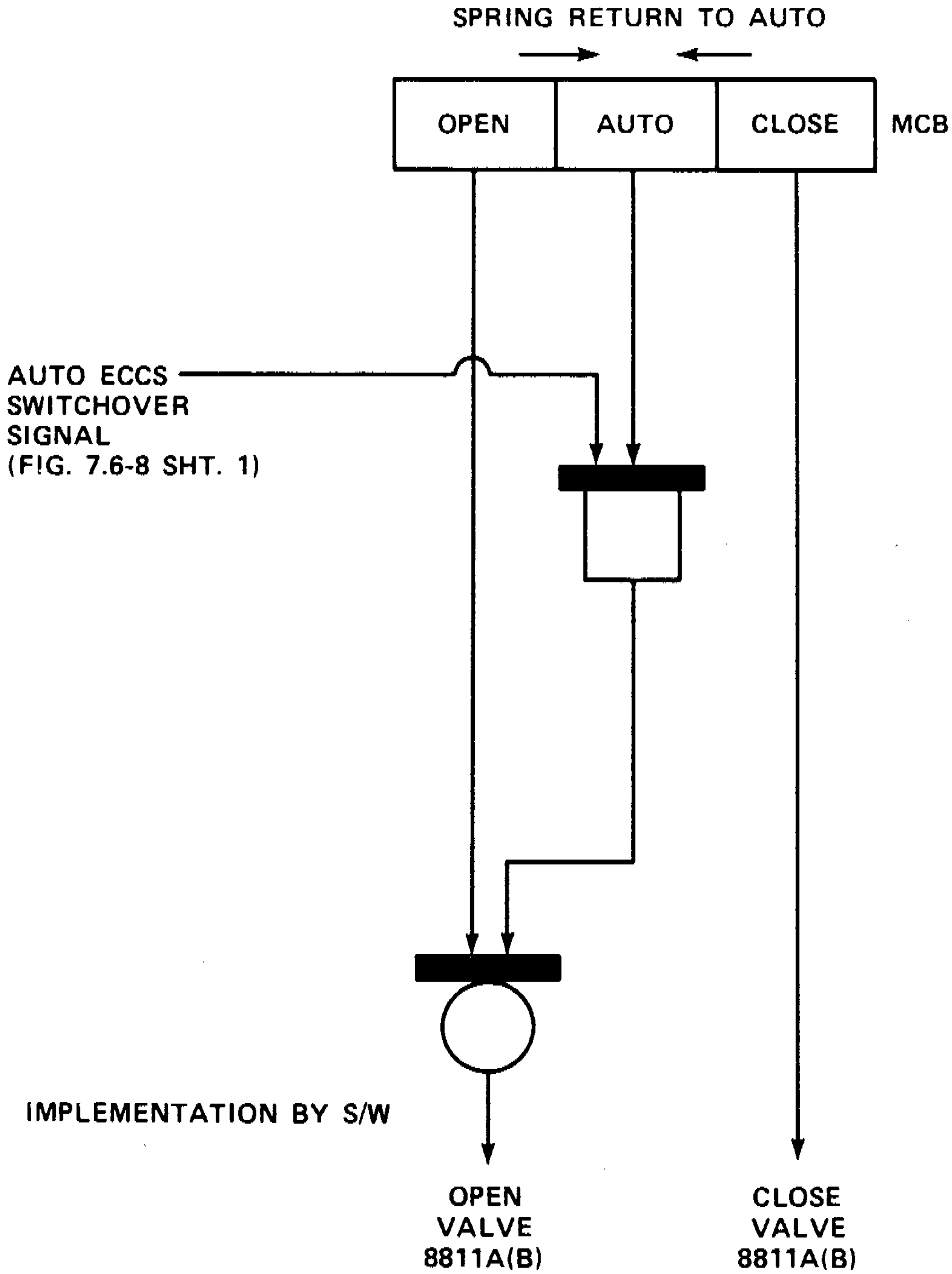


FIGURE 7.6-8 (SH. 2 OF 5)

LOGIC DIAGRAM FOR SWITCHOVER FROM INJECTION TO RECIRCULATION FOR RECIRCULATION SUPPLY VALVES

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

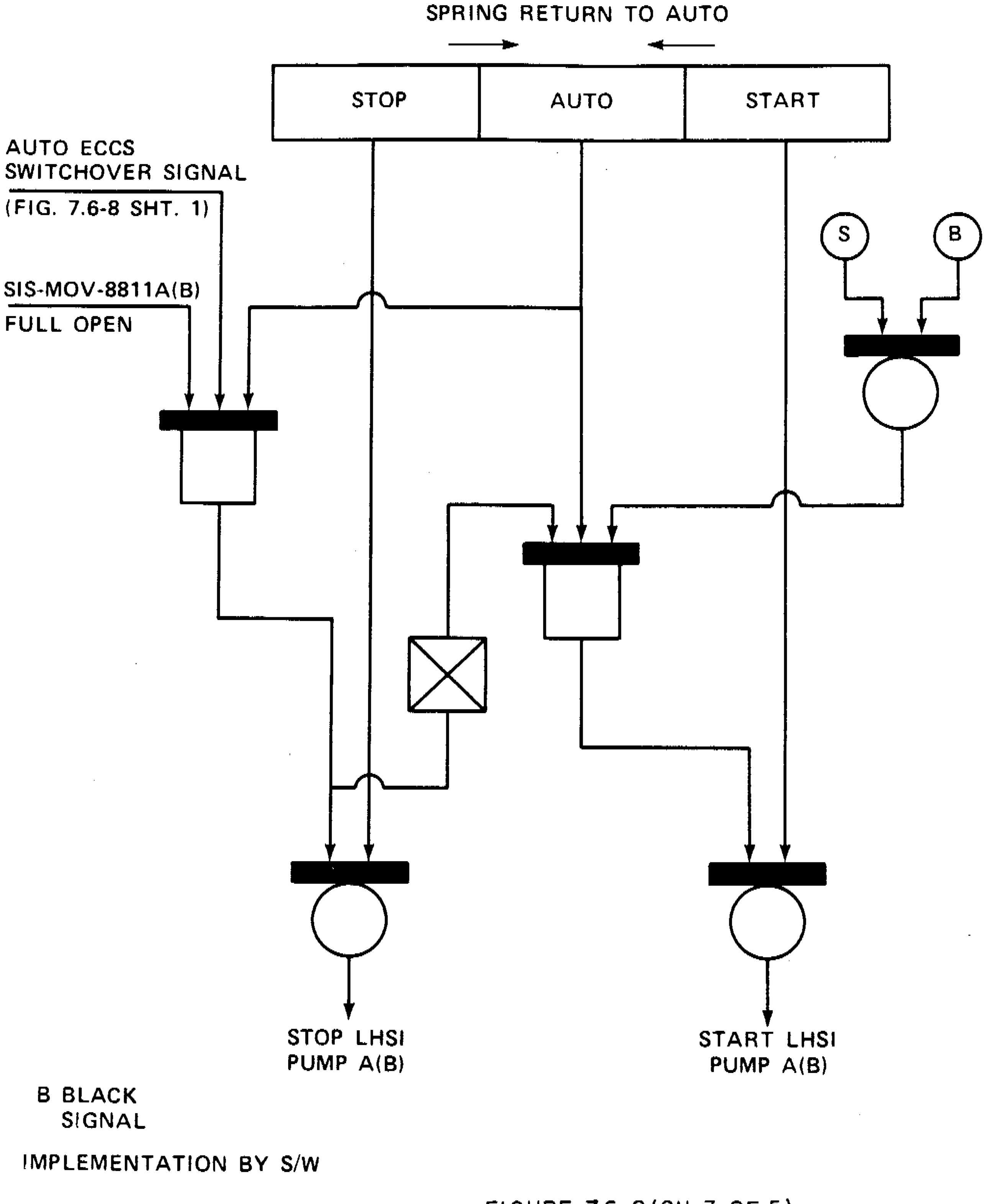


FIGURE 7.6-8 (SH. 3 OF 5)

LOGIC DIAGRAM FOR SWITCHOVER FROM INJECTION TO RECIRCULATION FOR LOW HEAD SAFETY INJECTION PUMPS

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

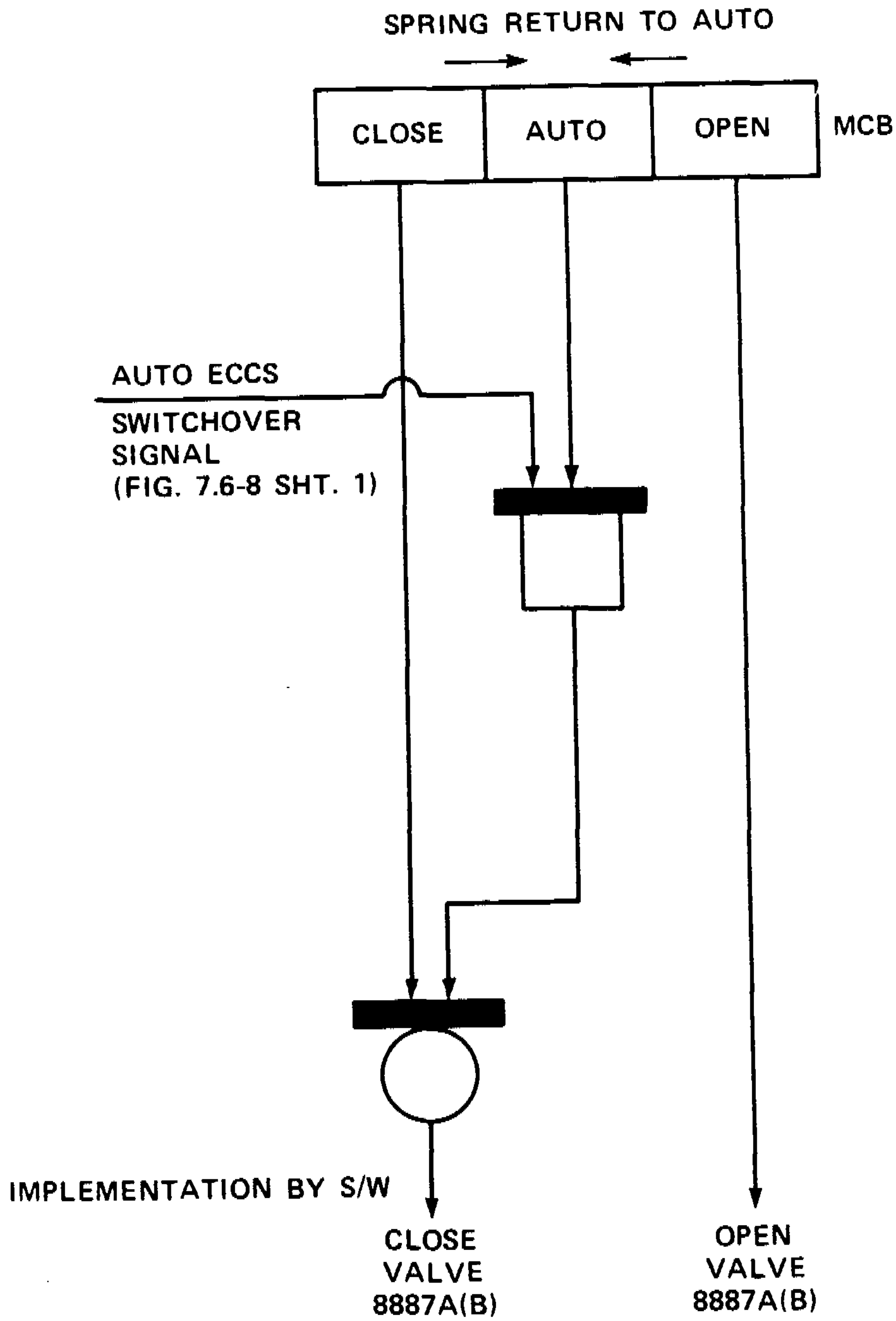


FIGURE 7.6-8 (SH. 4 OF 5)
LOGIC DIAGRAM FOR
SWITCHOVER FROM INJECTION TO
RECIRCULATION FOR LHSI HEADER
CROSS CONNECT VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

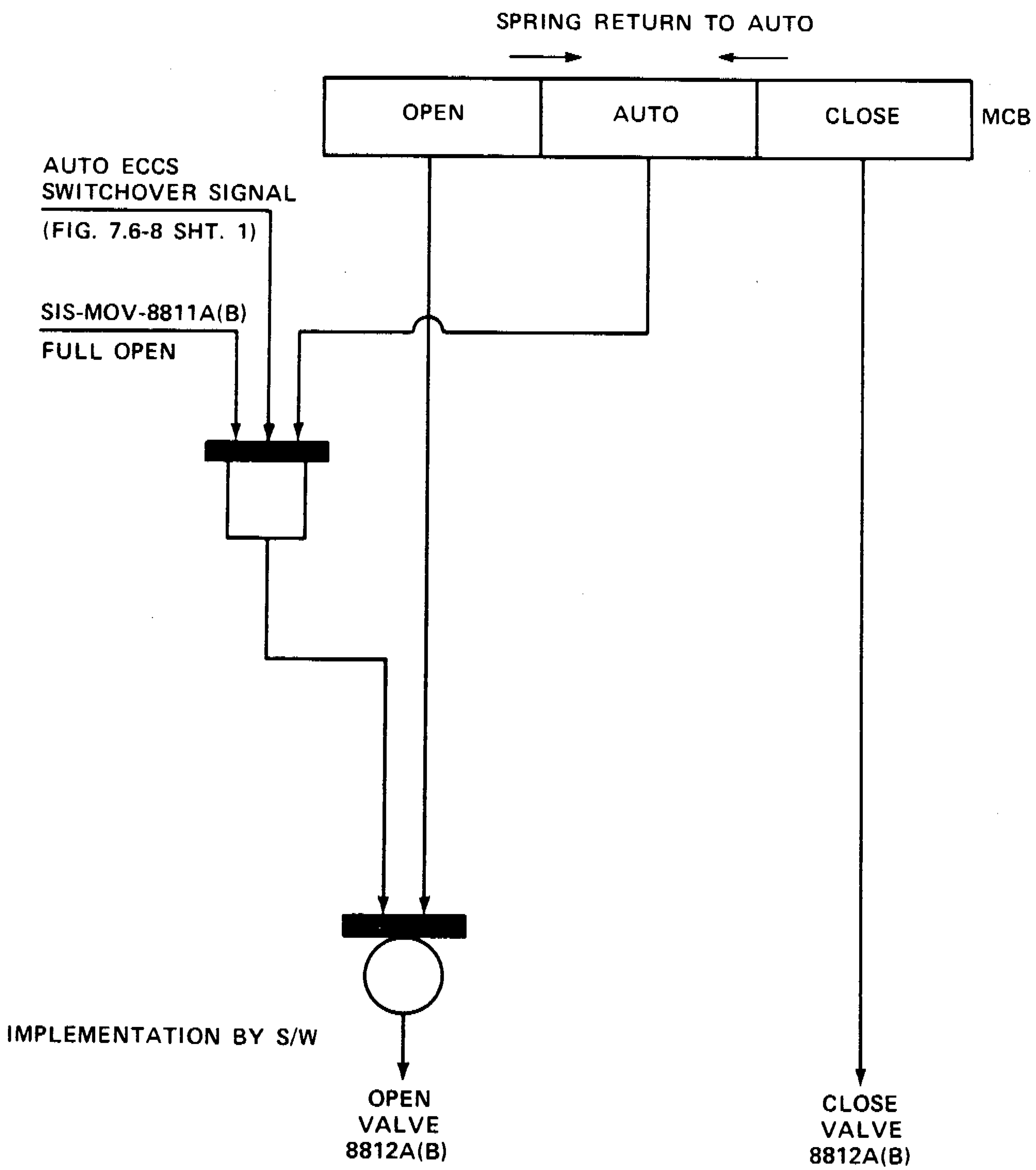


FIGURE 7.6-8 (SH. 5 OF 5)
LOGIC DIAGRAM FOR SWITCHOVER
FROM INJECTION TO RECIRCULATION
FOR CHARGING/SI SUPPLY VALVES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the Beaver Valley Power Station - Unit 2 (BVPS-2) control systems are:

1. To establish and maintain power equilibrium between primary and secondary system during steady state unit operation,

2. To constrain operational transients to preclude unit trip and reestablish steady-state unit operation, and

3. To provide the reactor operator with monitor instrumentation that indicates all required input and output control parameters of the systems.

4. To provide the operator the capability of assuming manual control of the system.

7.7.1 Description

The BVPS-2 control systems described in this section perform the following functions:

1. Reactor control system

    a. Enables the nuclear plant to accept a step load increase or decrease of 10-percent and a ramp increase or decrease of 5-percent/min within the load range of 15 to 100-percent without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

    b. Maintains reactor coolant average temperature T_{avg} within prescribed limits by creating the bank demand signals for moving groups of rod cluster control assemblies (RCCAS) during normal operational transients. Automatic control rod insertion may be used for temperature (Tavg) control. However, rod withdrawal can only be performed manually due to the deletion of the automatic rod withdrawal capability. Manual control of rod operation may be performed at any time within the range of the defined insertion limits. The T_{avg} control also supplies a signal to pressurizer water level control and steam dump control.

2. Rod control system

    a. Provides for reactor power modulation by manual or automatic control (automatic rod insertion only) of control rod banks in a preselected sequence and for manual operation of individual banks.

    b. Systems for monitoring and indicating

        (1) Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion.

(2) Permit display control rod positioning.

(3) Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit.

3. Control system interlocks

a. Prevent further withdrawal of the control banks when signal limits are approached that predict departure from nucleate boiling ratio (DNBR) limit or kw/ft limit.

b. Inhibit automatic turbine load change as required by the nuclear steam supply system.

4. Pressurizer pressure control

Maintains or restores the pressurizer pressure to the design pressure (which is well within reactor trip and relief and safety valve actuation set point limits) following normal operational transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer. Provides steam relief by controlling the pressurizer power-operated relief valves (PORVs).

5. Pressurizer water level control

Establishes, maintains, and restores pressurizer water level within specified limits as a function of the average coolant temperature. Changes in water level are caused by coolant density changes induced by the change in T_{avg} as a function of load. Water level control is produced by charging flow control (manual or automatic), as well as by manual selection of letdown orifices. Maintaining coolant level in the pressurizer within prescribed limits provides for control of the reactor coolant water inventory.

6. Steam generator water level control

a. Establishes and maintains the steam generator water level to within predetermined limits during normal operating transients.

b. Restores the steam generator water level to within predetermined limits at unit trip conditions. Regulates the feedwater flow rate such that under operation transients the heat sink for the reactor coolant system (RCS) does not decrease below a minimum. Steam generator water inventory control is manual or automatic through the use of feedwater control valves.

7. Steam dump control

   a. Permits BVPS-2 to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser as necessary to accommodate excess power generation in the reactor during turbine load reduction transients.

   b. Ensures that stored energy and residual heat are removed following a reactor trip to bring BVPS-2 to equilibrium no load conditions without actuation of the steam generator safety valves.

   c. Maintains BVPS-2 at no load conditions and permits a manually controlled cooldown of the nuclear plant.

8. Incore instrumentation

   Provides information on the neutron flux distribution and on the core outlet temperatures at selected core locations.

7.7.1.1 Reactor Control System

The reactor control system enables BVPS-2 to follow load changes including the acceptance of step load increases or decreases of 10 percent, and ramp increases or decreases of 5 percent/min within the load range of 15 to 100 percent without reactor trip, steam dump, or pressure relief (subject to possible xenon limitations). The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time.

The reactor control system controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, where:

$$T_{avg} = \frac{T_{hot(avg)} + T_{cold}}{2} \qquad (7.7\text{-}1)$$

The error between the programmed reference temperature (based on turbine first stage pressure) and the median of the T_{avg} measured temperatures (which is processed through a lead-lag compensation unit) from each of the reactor coolant loops constitutes the primary control signal, as shown in general on Figure 7.7-1 and in more detail on the functional diagram, Figure 7.2-1, Sheet 9. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. The median T_{avg} signal is also supplied to the pressurizer level control, steam dump control, and rod insertion limit monitoring control system.

The temperature inputs to the control systems are derived using the median signal selector.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

7.7.1.2 Rod Control System

7.7.1.2.1 Rod Control System

The rod control system receives rod speed and direction signals from the T_{avg} control system. The rod speed demand signal varies over the corresponding range of 8 to 72 steps/min depending on the magnitude of the input signal. Automatic rod withdrawal capabilities have been disabled for enhanced reactivity management. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

Rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment. The manual and automatic controls are further interlocked with the control interlocks (Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are two shutdown banks.

The control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into two groups to obtain smaller incremental reactivity changes per step. All RCCAs in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

Power to rod drive mechanisms is supplied by two motor-generator sets operating from two separate 480 V three-phase buses. Each generator is the synchronous type and is driven by a 200 hp induction motor. The ac power is distributed to the rod control power cabinets through the two series-connected reactor trip breakers.

The variable speed rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed. A summary of the RCCA sequencing characteristics is given as follows:

1. Two groups within the same bank are stepped such that the relative position of the groups will not differ by more than one step.

2. The control banks are programmed such that withdrawal of the banks is sequenced in the following order; control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence, that is, the last control bank withdrawn (bank D) will be the first control bank inserted.

3. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power level. The control bank insertion sequence is the opposite of the withdrawal sequence.

4. Overlap between successive control banks is adjustable between 0 to 50-percent (0 to 115 steps), with an accuracy of ±1 step.

5. Rod speeds for either the shutdown banks or manual operation of the control banks are capable of being controlled between a minimum of 8 steps/min and a maximum of 72 steps/min (+0 steps/min, -10 steps/min).

7.7.1.2.2 Rod Control System Features

Credible rod control equipment malfunctions which could potentially cause inadvertent positive reactivity insertions due to inadvertent rod withdrawal, incorrect overlap, or malpositioning of the rods are as listed:

1. Failures in the manual rod controls:

    a. Rod motion control switch (in-hold-out)

    b. Bank selector switch

2. Failures in the overlap and bank sequence program control:

    a. Logic cabinet systems

    b. Power supply systems

7.7.1.2.2.1 Failures in the Manual Rod Controls

The rod motion control switch is a three-position lever switch. The three positions are: in, hold, and out. These positions are effective when the bank selector switch is in manual. Failure of the rod motion control switch (contacts failing shorted or activated relay failures) would have the potential, in the worst case, to produce positive reactivity insertion by rod withdrawal when the bank selector switch is in the manual position or in a position which selects one of the banks.

When the bank selector switch is in the automatic position, the rods would obey the automatic commands and any failures in the rod motion control switch would have no effect on the rod motion regardless of whether the rod motion control switch is in the in, hold, or out position.

In the case where the bank selector switch is selecting a bank and a failure occurs in the rod motion switch that would command the bank to move out even when the rod motion control switch was in an in or hold position, the selected bank could inadvertently withdraw. This failure is bounded in the safety analysis (Chapter 15) by the uncontrolled bank withdrawal subcritical and at power transients. A reactivity insertion of up to 75 pcm/sec is assumed in the analysis due to rod movement. This value of reactivity insertion rate is consistent with the withdrawal of two banks.

A failure that can cause more than one group of four mechanisms to be moved at one time within a power cabinet is not a credible event, because the circuit arrangement for the moveable and lift coils would cause the current available to the mechanisms to divide equally between coils in the two groups (in a power supply). The drive mechanism is designed such that it will not operate on half-current. A second feature in this scenario would be the multiplexing failure detection circuit included in each power cabinet. This failure detection circuit would stop rod withdrawal (or insertion).

The second case considered in the potential for inadvertent reactivity insertion due to possible failures is when the bank selector switch is in the manual position. Such a case could produce a failure in the rod motion control switch, a scenario where the rods could inadvertently withdraw in a programmed sequence. The overlap and bank sequence are programmed when the switch selection is in either automatic or manual. This scenario is also bounded by the reactivity values assumed in the accident analysis (Chapter 15). In this case, the operator can trip the reactor, or the protection system would trip the reactor via power range neutron flux-high or overtemperature ΔT.

7.7.1.2.2.2 Failure of the Bank Selector Switch

A failure of the bank selector switch produces no consequences when the in-hold-out switch is in the hold position. This is due to the following design feature:

> The bank selector switch is series-wired with the in-hold-out lever switch for manual and individual control rod bank operation. With the in-hold-out lever switch in the hold position, the bank selector switch can be positioned without rod movement.

7.7.1.2.2.3 Failures in the Overlap and Bank Sequence Program Control

The rod control system design prevents the movement of the groups out of sequence, as well as limiting the rate of reactivity insertion. The main feature that performs the function of preventing malpositioning produced by groups out of sequence is included in the block supervisory memory buffer and control. This circuitry accepts and stores the externally generated command signals. In the event of an out of sequence input command to the rods while they are in movement, this circuit will inhibit the buffer memory from accepting the command. If a change of signal command appears, this circuit would stop the system after allowing the slave cyclers to finish their current sequencing. Failure of the components related to this system will also produce insertion limit and rod deviation alarms (Sections 7.7.1.3.3 and 7.7.1.3.4, respectively). Failures within the system such as failures of supervisory logic cards, pulser cards, etc, will also cause an urgent alarm.

1. An urgent alarm will be followed by the following actions:

    a. Automatic de-energizing of the lift coil and reduced current energizing of the stationary gripper coils and moveable gripper coils,

    b. Activation of the alarm light, urgent failure, on the power supply cabinet front panel, and

    c. Activation of rod control, urgent failure, annunciator window in the main control room.

2. The urgent alarm is produced in general by:

    a. Regulation failure detector,

    b. Phase failure detector,

    c. Logic error detector,

    d. Multiplexing error detector, and

    e. Interlock failure detector.

7.7.1.2.2.4 Logic Cabinet Failures

The rod control system is designed to limit the rod speed control signal output to a value that will cause the pulser (logic cabinet) to drive the control rod driving mechanism at 72 steps/min. If a failure should occur in the pulses or the reactor control system, the highest stepping rate possible is 77 steps/min, which corresponds to one step every 780 ms. A commanded stepping rate higher than 77 steps/min would result in go pulses entering a slave cycler while it is sequencing its mechanisms through a 780 ms step. This condition stops the control bank motion automatically and alarms are activated locally and in the main control room. It also causes the affected slave cycler to reject further go pulses until it is reset.

The positive reactivity insertion rates for failure modes are bounded by the Chapter 15 analysis assumptions.

7.7.1.2.2.5 Failures Causing Movement of the Rods Out of Sequence

No single failure was discovered (Shopsky 1977) that would cause a rapid uncontrolled withdrawal of control bank D (taken as worst case) when operating in the automatic bank overlap control mode with the reactor at near full power output. The analysis revealed that many of the failures postulated were in a safe direction and that rod movement is blocked by the rod urgent alarm.

7.7.1.2.2.6 Power Supply System Failures

Analysis of the power cabinet disclosed no single component failures that would cause the uncontrolled withdrawal of a group of rods serviced by the power cabinet. The analysis substantiates that the design of a power cabinet is fail-preferred in regards to a rod withdrawal accident if a component fails. The end results of the failure is either that of blocking rod movement or that of dropping an individual rod, or rods, or a group of rods. No failure with the power cabinet, which could cause erroneous drive mechanism operation, will remain undetected. Sufficient alarm monitoring (including an urgent alarm) is provided in the design of the power cabinet for fault detection of those failures which could cause erroneous operation of a group of mechanisms. As noted in the foregoing, diverse monitoring systems are available for detection of failures that cause the erroneous operation of an individual CRDM.

7.7.1.2.2.7 Conclusion

In summary, no single failure within the rod control system can cause either reactivity insertions or malpositioning of the control rods that would result in core thermal conditions not bounded by the analyses contained in Chapter 15.

7.7.1.3 Plant Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by Nuclear Instrumentation System

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure power level, axial power imbalance, and radial power imbalance. These channels are capable of recording overpower excursions up to 200-percent of full power. Suitable alarms are derived from these signals, as described in the following discussion.

The basic power range signals are:

1. Current from each upper section ionization chamber for each of the four power range detectors,

2. Current from each lower section ionization chamber for each of the four power range detectors, and

3. Total current from each of the four power range detectors (sum of the currents from top upper and lower section ionization chambers for each of the four power range detectors).

Derived from these basic signals are the following:

1. Indicated nuclear power (four signals).

2. Lower radial flux tilt alarm (ratio of the maximum of the four lower ionization chamber currents to the average of the four lower ionization chamber currents).

3. Upper radial flux tilt alarm (ratio of the maximum of the four upper ionization chamber currents to the average of the four upper ionization chamber currents).

4. Average flux deviation alarm (ratio of the maximum channel power (total current for upper and lower sections to the minimum channel power of the four channels).

5. Axial flux difference indication (ΔI) (upper ionization chamber current minus the lower ionization chamber current for each detector).

6. Axial offset deviation alarms (ratio of the difference between the upper and lower ionization chamber currents for a detector to the sum of the upper and lower ionization chamber currents for that detector). This is done for each detector by the BVPS-2 computer.

Nuclear power and axial unbalance are selectable for recording.

7.7.1.3.2 Rod Position Monitoring of Control Rods

Two separate systems are provided to sense and display control rod position as described below:

1. Digital Rod Position Indication System

   The digital rod position indication system measures the actual position of each control and shutdown rod using a detector which consists of discrete coils mounted concentrically over a hollow tube. The tube fits over the rod travel housing. The coils are located axially along the tube and magnetically sense the position of the rod drive shaft as it approaches the detector coil location. For each detector, the coils are interlaced into two data channels and are connected to the containment electronics (data A and B) by separate multiconductor cables. By employing two separate channels of information, the digital rod position indication system can continue to function (at reduced accuracy) when one channel fails. Multiplexing is used to transmit the digital position signals from the containment electronics to the control board display unit.

   There are four banks of control rods and two banks of shutdown rods. Each bank contains eight rods.

   The rod positions for the control banks of rods are indicated by columns of light-emitting diodes (LEDs) that illuminate in discrete steps at six-step intervals throughout the range of travel of each control rod. Since the shutdown rods are normally either at the bottom or fully withdrawn, the rod positions for the shutdown banks of rods are indicated in discrete steps in six-step intervals, from rod bottom to 18 steps and from 210 steps to 228 steps (actual indication at rod bottom and rod top positions). A single LED for each shutdown rod illuminates when that particular rod is in an intermediate position between the two discrete positions discussed above. The accuracy of indication is ± 4 steps throughout the range of travel for each control rod, and from rod bottom to 18 steps and from 210 steps to 228 steps for each shutdown rod.

Included in the system is a rod at bottom signal for each shutdown rod and control rod that operates a local alarm and activates a control room annunciator when the rod is at the bottom position.

2. Demand Position System

The demand position system counts pulses generated in the rod drive control system to provide a digital readout of the demanded bank position.

The demand position and digital rod position indication systems are separate systems, but safety criteria were not involved in the separation, which was a result only of operational requirements. Operating procedures require the reactor operator to compare the demand and indicated (actual) readings from the rod position indication system to verify operation of the rod control system.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the RCS loop T) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip, provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion such that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increase with increasing power, the allowable rod insertion limits must be raised (the rods must be withdrawn further) with increasing power. Two parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power.

The rod insertion limit monitor is a feature that alerts the operator to a reduced shutdown reactivity condition. The value for E is chosen such that the low-low alarm would normally be actuated before the insertion limit is reached. The value for D is chosen to allow the operator to follow normal boration procedures. Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail on the functional diagram, Figure 7.2-1, Sheet 9. In addition to the rod insertion monitor for the control banks, the BVPS-2 computer, which monitors individual rod positions, provides an alarm that is associated with the rod deviation alarm discussed in Section 7.7.1.3.4. This alarm is provided to warn the operator if any shutdown RCCA leaves the fully withdrawn position.

Rod insertion limits are established by:

1. Establishing the allowed rod reactivity insertion at full power consistent with the purposes given previously,

2. Establishing the differential reactivity worth of the control rods when moved in normal sequence,

3. Establishing the change in reactivity with power level by relating power level to rod position, or

4. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variation in concentration during core life provide an additional check on the reactivity statue of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarms

The demanded and measured rod position signals are displayed on the main control board. They are also monitored by the BVPS-2 computer, which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system.

7.7.1.3.5 Rod Bottom Alarm

A rod bottom signal for the control rods bistable in the rod position system is used to operate a control relay, which generates the rod bottom rod drop alarm.

7.7.1.4 Control System Interlocks

The listing of the BVPS-2 control system interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. It is noted that the designation numbers for these interlocks are preceded by C. The development of these logic functions is shown in the functional diagrams, Figure 7.2-1, Sheets 9 to 16.

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions, which could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

Rod stops are the C-1, C-2, C-3, and C-4 control interlocks identified in Table 7.7-1. The C-3 rod stop, derived from overtemperature ΔT, and the C-4 rod stop, derived from overpower ΔT, are also used for turbine runback, which is discussed in the following section.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two out of three coincidence logic is used.

A rod stop and turbine runback are initiated when $\Delta T > \Delta T_{rod\ stop}$ for both the overtemperature and the overpower condition.

For either condition in general

$$\Delta T_{rod\ stop} = \Delta T_{setpoint} - B_p$$

where:

Bp = A set point bias

$AT_{setpoint}$ = The overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the two conditions.

The turbine runback is continued until ΔT is equal to or less than ΔT rod stop. This function serves to maintain an essentially constant margin to trip.

7.7.1.5 Pressurizer Pressure Control

The RCS pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electric immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on when the pressurizer pressure- controlled signal demands approximately 100-percent proportional heater power.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given set point. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock in the pressurizer spray line and to help maintain uniform water chemistry and temperature in the pressurizer.

The pressurizer PORVs limit system pressure for large positive pressure transients. In the event of a large load reduction not exceeding the design plant load rejection capability, the pressurizer PORVs might be actuated for the most adverse conditions, for example, the most negative Doppler coefficient and the minimum incremental rod worth. The relief capacity of the pressurizer PORVs is sized large enough to limit the system pressure to prevent actuation of high pressure reactor trip for the preceding condition.

A block diagram of the pressurizer pressure control system on Figure 7.7-4.

7.7.1.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant adjusts to the various temperatures, the steam water interface moves to absorb the variations with relatively small pressure disturbances.

The water inventory in the RCS is maintained by the CVCS. During normal plant operation, the charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant median average temperature. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

A block diagram of the pressurizer water level control system is shown on Figure 7.7-5.

7.7.1.7 Steam Generator Water Level Control

Each steam generator is equipped with a three-element feedwater flow controller which maintains a programmed water level. The three-element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, the programmed level, and the pressure-compensated steam flow signal. Isolated input signals to the feedwater control system are provided from the protection system and processed by a median signal selector as discussed in Section 7.2.2.2.3, Control and Protection System Interaction. Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature and the reactor has tripped. Manual override of the feedwater control system is available at all times.

When BVPS-2 is operating at very low power (as during start-up), the steam and feedwater flow signals will not be useable for control. Therefore, a secondary automatic control system is provided for operation at low power. This system uses the steam generator water level programmed set point signal in conjunction with the power range neutron flux signal in a bypass valve that is in parallel with the main feedwater regulating valve. Switchover from the bypass feedwater control system (FWCS) (low power) to the main FWCS is initiated by the operator at approximately 15-percent power.

A block diagram of the steam generator water level control system is shown on Figure 7.7-6.

7.7.1.8 Steam Dump Control

The steam dump system, as described in Section 10.4.4, is capable of accepting greater than 40 percent of full load steam flow at full load steam pressure, which supports the BVPS-2 50 percent load rejection.

The automatic steam dump system is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the RCS. By passing main steam directly to the condenser and atmosphere, an artificial load is thereby maintained on the primary system. The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions.

If the difference between the reference T_{avg} (T_{ref}) based on turbine first stage pressure and the lead/lag compensated median T_{avg} exceeds a predetermined amount, and the interlock mentioned as follows is satisfied, a demand signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine first stage pressure. It is provided to unblock the dump valves when the rate of load rejection exceeds a preset value corresponding to a 10-percent step load decrease or a sustained ramp load decrease of 5-percent/min.

A block diagram of the steam dump control system is shown on Figure 7.7-7.

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensated median T_{avg} and the reference T_{avg} is based on turbine first stage pressure.

The T_{avg} signal is the same as that used in the Rod Control System. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the BVPS-2 thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available, in this situation steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Plant Trip Steam Dump Controller

Following a reactor trip, the load rejection steam dump controller is defeated and the reactor trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead/lag compensated median T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined set point, the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude indicating that the RCS T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the BVPS-2 trip controller to regulate the rate of removal decay heat and thus gradually establish the equilibrium hot standby condition.

Following a reactor trip only, sufficient steam dump capacity is necessary to maintain steam pressure below the steam generator safety valve set point (approximately 40-percent capacity to the condenser), the two groups of valve are opened. The error signal determines whether a group is to be tripped open or modulated open. The valves are modulated when the error is below the trip-open set points.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal is maintained by the steam generator pressure controller (manually selected), which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers, which are used during the initial transient following turbine reactor trip or load rejection.

7.7.1.9 Incore Instrumentation

The incore instrumentation system consists of chromel-alumel thermocouples, at fixed core outlet positions, and moveable miniature neutron detectors, which can be positioned at the center of selected fuel assemblies anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown on Figure 7.7-8.

7.7.1.9.1 Thermocouples

The chromel-alumel thermocouples are inserted into guide tubes that penetrate the reactor vessel head through seal assemblies and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals, a conoseal and swage type seal from conduit to head. The thermocouples are supported in guide tubes in the upper core support assembly. Thermocouple readings are monitored by the computer, with backup readout provided by a precision indicator with manual point selection located in the main control room. Information from the incore instrumentation is available even if the BVPS-2 computer is not in service.

7.7.1.9.2 Moveable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. The stainless steel detector shell is welded to the leading end of helical wrap drive cable and to stainless steel sheathed coaxial cable.

The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table. Their distribution over the core is nearly uniform, with about the same number of thimbles located in each quadrant.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal table. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal table is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of drive assemblies, five path rotary transfer assemblies and ten path transfer assemblies, as shown on Figure 7.7-8. The drive system pushes hollow helical wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor, which pushes a helical wrap drive cable and a detector through a selective thimble path by means of a special drive box, and includes a storage device that accommodates the total drive cable length.

Cap plugs will be provided to plug leaking thimbles. A small leak would probably not prevent access to the seal table and thus a leaking thimble could be isolated. A large leak might require cold shutdown for access to the isolation seal table.

7.7.1.9.3 Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while recording neutron flux versus detector position. The control system is located in the main control room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One five path operation selector is provided for each drive unit to insert the detector in one of five functional modes of operation. One ten path operation selector is also provided for each drive unit that is then used to route a detector into any one of up to ten selectable paths. A common path is provided to permit cross calibration of the detectors.

The main control room contains the necessary equipment for control, position indication, and flux recording for each detector.

Flux-mapping consists of selecting flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven to the top of the core and stopped automatically. A recording (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner, other core locations are selected and recorded. Each detector provides axial flux distribution data along the center of a fuel assembly. Detector output is then analyzed to obtain a flux map of the core.

The number and location of these thimbles have been chosen to permit measurement of local to average peaking factors to an accuracy of ±5-percent (95-percent confidence). Measured nuclear peaking factors will be increased by 5-percent to allow for this accuracy. An additional increase to the measured nuclear peaking factor for reduced flux thimble availability is discussed in Sections 3.3.7 and 5.1.6 of the Licensing Requirements Manual. This system is used to verify that the power distribution is within the limits of the Technical Specifications.

Operating plant experience has demonstrated the adequacy of the incore instrumentation in meeting the design bases stated.

7.7.1.10 Ultrasonic Feedwater Flow Meter

The ultrasonic feedwater flow meter system is used in measuring feedwater flow and calculating thermal power. Nuclear plants are licensed to operate at a specified core thermal power, and the uncertainty of the calculated values of this thermal power determines the probability of exceeding the power levels assumed in the design-basis transient and accident analyses.

The ultrasonic feedwater flow meter system provides measurements of feedwater mass flow and temperature yielding a total power uncertainty of ±0.6% of reactor thermal power. The system consists of an electronic cabinet located in the Process Controls Area, and a measurement section (spool piece) installed in the 26-inch main feedwater header. Transducers that transmit and receive the pulses are mounted in the measurement section spool piece.

Digital ultrasonic feedwater flow meter electronics are controlled by software to measure line integral velocities at precise locations with respect to the pipe centerline. Transit time differences between pulses are used to determine the fluid velocity and temperature. The mass flow rate and feedwater temperature are displayed on the local display panel, and transmitted to the plant process computer for use in the calorimetric measurement.

An alarm is provided in the control room to alert operators should the system require maintenance.

The system software was developed and is maintained using a verification and validation program compliant with IEEE standard 7-4.3.2-1993 and ASME standard NQA-2a-1990.

7.7.2 Analysis

The BVPS-2 control systems are designed to assure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed with a high level of reliability.

Proper positioning of the control rods is monitored in the main control room by bank arrangements of the individual position columns for each RCCA. A rod deviation alarm alerts the operator of a deviation of one RCCA from the other rack in that bank position. There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the main control room for each full length RCCA. Four excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Overall reactivity control is achieved by the combination of soluble boron and RCCAs. Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes is accomplished by the reactor control system which automatically or manually moves RCCAs. This system uses input signals that include neutron flux, coolant temperature, and turbine load.

The BVPS-2 control systems will prevent an undesirable condition in the operation of the nuclear plant that, if reached, will be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst-case failure modes of the BVPS-2 control systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15, such as the following:

1. Uncontrolled RCCA withdrawal from a subcritical condition,

2. Uncontrolled RCCA withdrawal at power

3. Misalignment of RCCA

4. Loss of external electrical load and/or turbine trip,

5. Loss of all ac power to the station auxiliaries (station blackout),

6. Excessive heat removal due to feedwater system malfunctions,

7. Excessive load increase incident, and

8. Accidental depressurization of the RCS.

These analyses will show that a reactor trip set point is reached in time to protect the health and safety of the public under these postulated incidents and that the resulting coolant temperatures will produce a DNBR well above the limiting value of 1.30. Thus, there will be no clad damage and no release of fission products to the RCS under the assumption of these postulated worst-case failure modes of the BVPS-2 control system.

7.7.2.1 Separation of Protection and Control Systems

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Test results have shown that postulated faults on the isolated output portion of the circuit (nonprotection side of the circuit) will not affect the input (protection) side of the circuit.

Where a single random failure can cause a control system action that results in a condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. This meets the applicable requirements in Paragraph 4.7 of IEEE Standard 279-1971.

The loop T_{avg} and ΔT channel required inputs to the steam dump system, the reactor control system, the control rod insertion monitor and the pressurizer level control system are electrically isolated prior to being routed to the control cabinets. A median signal is then calculated for T_{avg} and ΔT in the control cabinets utilizing a Median Signal Selector (MSS) for input to the appropriate control systems.

7.7.2.2 Response Considerations of Reactivity

Reactor shutdown with control rods is completely independent of the control functions, since the trip breakers interrupt power to the rod drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. The design meets the requirements of General Design Criterion (GDC) 25.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the partially inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank. This feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, rod deviation would be displayed on a main control room annunciator, and the individual rod position readouts would indicate the relative positions of the other rods in the bank. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of control and shutdown rods in the system is divided into two groups (group 1 and group 2) of up to four mechanisms each. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. The group 1 and group 2 power circuits are installed in different cabinets, as shown on Figure 7.7-9, which also shows that one group is always within one step (5/8 inch) of the other group. A definite sequence of actuation or deactuation of the stationary grippers moveable grippers and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Since the four stationary grippers, moveable grippers, and lift coils associated with the RCCAs of a rod group are driven in parallel, any single failure which could cause rod withdrawal would affect a minimum of one group of RCCAs. Mechanical failures are in the direction of insertion, or immobility.

Figure 7.7-10 is provided for a discussion of design features that assure that no single electrical failure could cause the accidental withdrawal of a single RCCA from the partially inserted bank at full power operation.

Figure 7.7-10 shows the typical parallel connections on the lift, moveable, and stationary coils for a group of rods. Since single failures in the stationary or moveable circuits will result in dropping or preventing rod(s) motion, the discussion of single failure will be addressed to the lift coil circuits: 1) due to the method of wiring the pulse transformers which fire the lift coil multiplex thyristors, three of the four thyristors in a rod group when required to fire if, for example, the gate signal lead failed open at open at point X^1. Upon up demand, one rod in group 1 and four rods in group 2 would withhdraw. A second failure at point X_2 in the group 2 circuit is required to withdraw an RCCA; 2) timing circuit failures will affect the four mechanisms of a group or the eight mechanisms of the bank and will not cause a single rod withdrawal; and 3) more than two simultaneous component failures are required (other than the open wire failures) to allow withdrawal of a single rod.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper 2 out of 16 wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016 x 10^{-6}/hr by MIL-HDBK-217D. These wire failures would have to be accompanied by failure, or disregard, of the preceding indications. The probability of this occurrence is therefore too low to have any significance.

Concerning the human element, to erroneously withdraw a single RCCA the operator would have to improperly set the bank selector switch, the lift coil disconnect switches, and hold the manual switch in the out position. In addition, the rod position indicators would have to be disregarded or ineffective. Such a series of errors would require a complete lack of understanding and administrative control. A probability number cannot be assigned to a series of errors such as these.

The rod position indication system provides direct visual displays of each control rod assembly position. The BVPS-2 computer has alarms for deviation of rods from their banks. In addition, a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility reactivity control systems are such that acceptable fuel damage limits will not be exceeded even in the event of a single malfunction of either system.

An important feature of the control rod system is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth RCCA is postulated to remain stuck in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the main control board. The control board position readouts, one for each control rod, give the BVPS-2 control room operator the actual position of the rod in steps. The indications are grouped by banks (for example, control bank A, control bank B, etc) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation.

The BVPS-2 computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than a predetermined amount, the rod deviation alarm is actuated. Misaligned RCCAs are also detected and alarmed in the main control room via the flux tilt monitoring system, which is independent of the BVPS-2 computer.

Isolated signals derived from the nuclear instrumentation system (Lipchak 1974) are compared with one another to determine if a preset amount of deviation of average power level has occurred. Should such a deviation occur, the comparator output will operate a bistable unit to actuate a main control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. The design of the plant control systems meets the requirements of GDC 23.

The CVCS can compensate for all xenon reactivity transients. The CVCS is not used, however, to compensate for the reactivity effects of fuel/water temperature changes accompanying power level changes. The CVCS will maintain the reactor in the cold shutdown state irrespective of the disposition of the control rods.

The rod control system can compensate for xenon reactivity transients over the allowed range of rod travel. Xenon transients of larger magnitude must be accommodated by boration or by reactor trip. The rod control system can also compensate for the reactivity effects of fuel/water temperature changes accompanying power changes over the full range from full load to no load at the design maximum load update.

7.7.2.3 Step Load Changes Without Steam Dump

The BVPS-2 control system restores equilibrium conditions, without a trip, following a plus or minus 10-percent step change in load demand over the 15 to 100 percent power range with a combination of manual and automatic control. Automatic control allows control rod insertion only. With automatic rod withdrawal disabled, control rod withdrawal can only be performed manually. Steam dump is blocked for load decrease less than or equal to 10-percent. A load demand greater than full power is prohibited by the turbine control load limit devices.

The BVPS-2 control system minimizes the reactor coolant average temperature deviation during the transient within a given value and restores average temperature to the programmed set point. Excessive pressurizer pressure variations are prevented by using spray and heaters and pressurizer PORVs in the pressurizer.

The reactor control system limits nuclear power overshoot to acceptable values following a 10-percent increase in load to 100-percent.

7.7.2.4 Loading and Unloading

Ramp loading and unloading of 5-percent/min can be accepted over the 15 to 100-percent power range with a combination of manual and automatic control without tripping the plant. Automatic control allows control rod insertion only. With automatic rod withdrawal disabled, control rod withdrawal can only be performed manually. The function of the reactor control system is to maintain the coolant average temperature as a function of turbine generator load.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The pressurizer spray limits the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed such that the water level is above the set point for heater cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in nuclear power and to provide sufficient margin in the overpower and overtemperature ΔT set points.

7.7.2.5 Load Rejection Furnished by Steam Dump System

When a load rejection occurs, if the difference between the required temperature set point of the RCS and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the rod control system. Reduction of the reactor power is automatic. The steam dump flow reduction is as fast as RCCAs are capable of reducing nuclear power.

The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam dump steam flow capacity is greater than 40 percent of full load steam flow at full load steam pressure, which supports the BVPS-2 50 percent load rejection.

The steam dump flow reduces proportionally as the average coolant temperature is reduced. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value. The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

7.7.2.6 Turbine Generator Trip With Reactor Trip

Whenever the turbine generator trips at an operating power above the P-9 permissive setpoint, the reactor also trips. The turbine generator is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the equivalent saturation pressure of the main steam safety valve set point. The thermal capacity of the RCS is greater than that of the secondary system, and because the full load average temperature is greater than the no load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of feedwater to the steam generators.

The steam dump system is controlled from the reactor coolant average temperature signal, whose set point values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves. With the dump valves open, the average coolant temperature starts to reduce quickly to the no load set point. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is bypassed.

Following the turbine trip with reactor trip above the P-9 permissive setpoint, the feedwater flow is cut off when the average coolant temperature decreases below a given temperature or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the desired value. Residual heat removal is maintained by the steam header pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers, which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the low level heater cutoff set point. If heaters become uncovered following the trip, the CVCS will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The steam dump and feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no load temperature following the trip, to ensure adequate reactivity shutdown margin.

7.7.2.7 Primary Component Cooling Water System

The primary component cooling water (PCCW) system, described in Section 9.2.2.1, supplies cooling water to various non-nuclear safety (NNS) class systems during normal plant operation. Under accident conditions or loss of power, the NNS class portion of the system is isolated and no cooling is provided.

Water level in the surge tank for the neutron shield tank is maintained manually. High and low water levels are alarmed in the main control room. The reactor vessel support shield tank has a temperature element on the downstream side with alarm and indication in the main control room.

Temperature is controlled in each of the following pieces of equipment by temperature control valves on the downstream side of each:

1. Boron recovery system

    a. Bottoms cooler
    b. Distillate cooler
    c. Evaporator condenser

2. Radioactive liquid waste system

    a. Bottoms cooler
    b. Distillate cooler
    c. Evaporator condenser

3. Radioactive gaseous waste system

    a. Compressor cooler
    b. Trim cooler
    c. Condenser

The compressor coolers are also equipped with local temperature indication.

During the life of BVPS-2, the NNS class portions of the PCCW system are either in continuous or intermittent operation. All components are accessible for periodic visual inspections.

Section 7.3 discusses the safety-related portion of the PCCW system.

7.7.2.8 Containment Leakage Monitoring System

The containment system leakage monitoring system is not an engineered safety features system. It is an NNS class system. The containment leakage monitoring system is described in Section 6.2.6.

7.7.2.9 Turbine Control System

A discussion of the turbine control system, including the redundant turbine overspeed protection system, is presented in Sections 10.2.2.4 and 10.2.4.

7.7.2.10 Plant Safety Monitoring System

The plant safety monitoring system (PSMS) is used to process and output the inadequate core cooling (ICC) variables in proper format to internal displays, and external indicators, displays, cabinets and other equipment. The PSMS consists of three types of modular components: the remote processing unit (RPU), the display processing unit (DPU), and the display. These components perform the data acquisition and processing, the data base consolidation and comparison, and the data selection and display, respectively.

The system is seismically and environmentally qualified, is configured to address single-failure criteria, and qualification details are available in Section 3.10 and 3.11. In addition, the PSMS has the capability for on-line testing without affecting reactor protection and control.

The display modules are redundant, qualified, graphic/alpha-numeric modules for displaying reactor vessel level core cooling margin ($T_{saturation}$), and the core exit thermocouples on demand. These displays will be used to detect the approach to inadequate core cooling.

Sections 3.10 and 3.11 provided details of the seismic and environmental qualification.

7.7.2.13 High-High Steam Generator Water Level Trip System

A two out of three high-high steam generator water level signal in any loop is called "the high-high steam generator water level trip" and the signal will cause feedwater isolation and trip the turbine. This trip is modeled in the safety analysis to mitigate the consequences of an Excessive Heat Removal Due to Feedwater System Malfunction events. This trip provides equipment protection since it limits moisture carryover that could damage the turbine blading.

When the water level in any steam generator reaches the high-high water level setpoint, the P-14 interlock is activated. Table 7.7-1 lists additional information pertaining to this function. Once activated, a P-14 signal will trip the turbine, trip all main feedwater pumps, close the main feedwater control valves, close the main feedwater control bypass valves, and close all main feedwater isolation valves. This function is displayed on the Functional Diagram for Main Feedwater Control and Isolation shown on Figure 7.3-18.

7.7.3 References for Section 7.7

FENOC Letter to U.S. Nuclear Regulatory Commission, License Amendment Request Nos. 289 and 161 (Attachment C, Items 6 and 8), Letter Number L-01-006, dated January 18, 2001.

Lipchak, J.B. and Stokes, R.A. 1974. Nuclear Instrumentation System. WCAP-8255 (for background information only).

Shopsky, W.E. 1977. Failure Modes and Effects Analysis of the Solid State Full Length Rod Control System. WCAP-8976.

U.S. Department of Defense 1982. Reliability Prediction of Electronic Equipment. MIL-HDBK-217D.

USNRC - Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment Nos. 243 and 122 to Facility Operating License Nos. DPR-66 and NPF-73, Page 5, dated September 24, 2001.

Westinghouse 1980. Westinghouse Reactor Vessel Level Instrumentation System for Monitoring Inadequate Core Cooling. December 1980.

Tables for Section 7.7

TABLE 7.7-1

BVPS-2 CONTROL SYSTEM INTERLOCKS

Designation	Derivation	Function
C-1	1/2 Neutron flux (intermediate range) above set point	Blocks control rod withdrawal
C-2	1/4 Neutron flux (power range) above set point	Blocks control rod withdrawal
C-3	2/3 Overtemperature ΔT above set point	Blocks control rod withdrawal Actuates turbine runback via load reference
C-4	2/3 Overpower ΔT above set point	Blocks control rod withdrawal Actuates turbine runback via load reference
C-7	1/1 Time derivative (absolute value) of turbine first stage pressure (decrease only) above set point	Makes steam dump valves available for either tripping or modulation
P-4[(1)]	Reactor trip breakers open	Blocks steam dump control via load rejection T_{avg} controller Makes half of the steam dump valves available for either tripping or modulation
	The following condition exists when P-4 is not active	Blocks steam dump control via reactor trip T_{avg} controller (this function is provided by absence of P-4)

TABLE 7.7-1 (Cont)

Designation	Derivation	Function
C-9	Any condenser pressure above set point, or all circulation water pump breakers open	Blocks steam dump to condenser
P-14	2/3 steam generator level above setpoint on any steam generator (presence of signal performs or permits functions shown)	Closes all feedwater isolation valves trip feedwater pumps actuates turbine trip[(2)]
C-20	2/2 Turbine first stage pressure ≥ 40% of nominal pressure at 100% power. Delayed off (Ref 4.3.1.7)	Enables AMSAC

(1) See Table 7.3-3 for engineered safety features actuation system functions.

(2) The motor driven AFW pumps start indirectly as a result of the Main Feedwater Pump trip caused by this signal.

REV. 15

NOTES:

1. TEMPERATURES ARE MEASURED AT STEAM GENERATOR'S INLET AND OUTLET
2. PRESSURE IS MEASURED AT THE PRESSURIZER
3. AUTOMATIC ROD WITHDRAWAL IS DISABLED

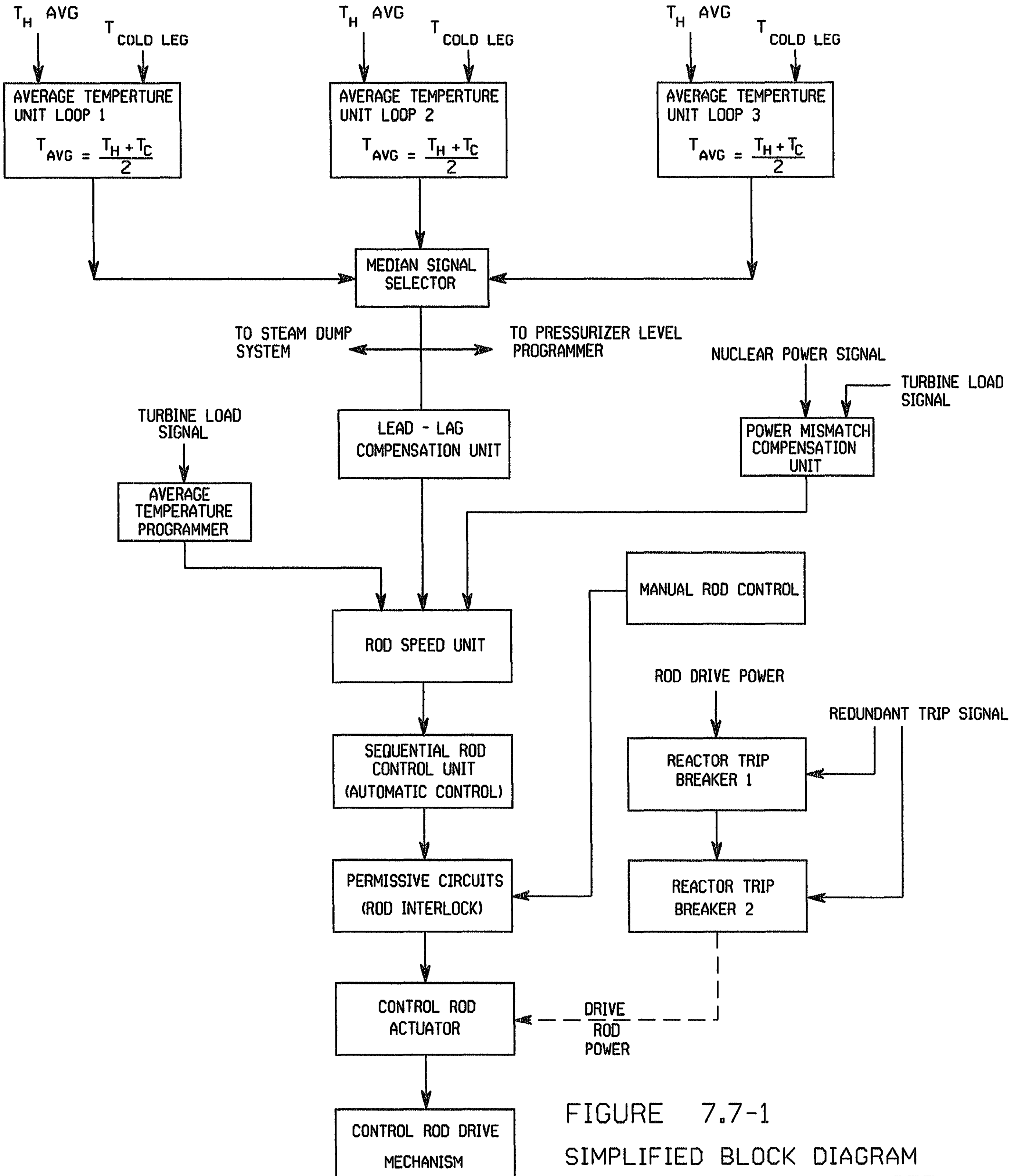


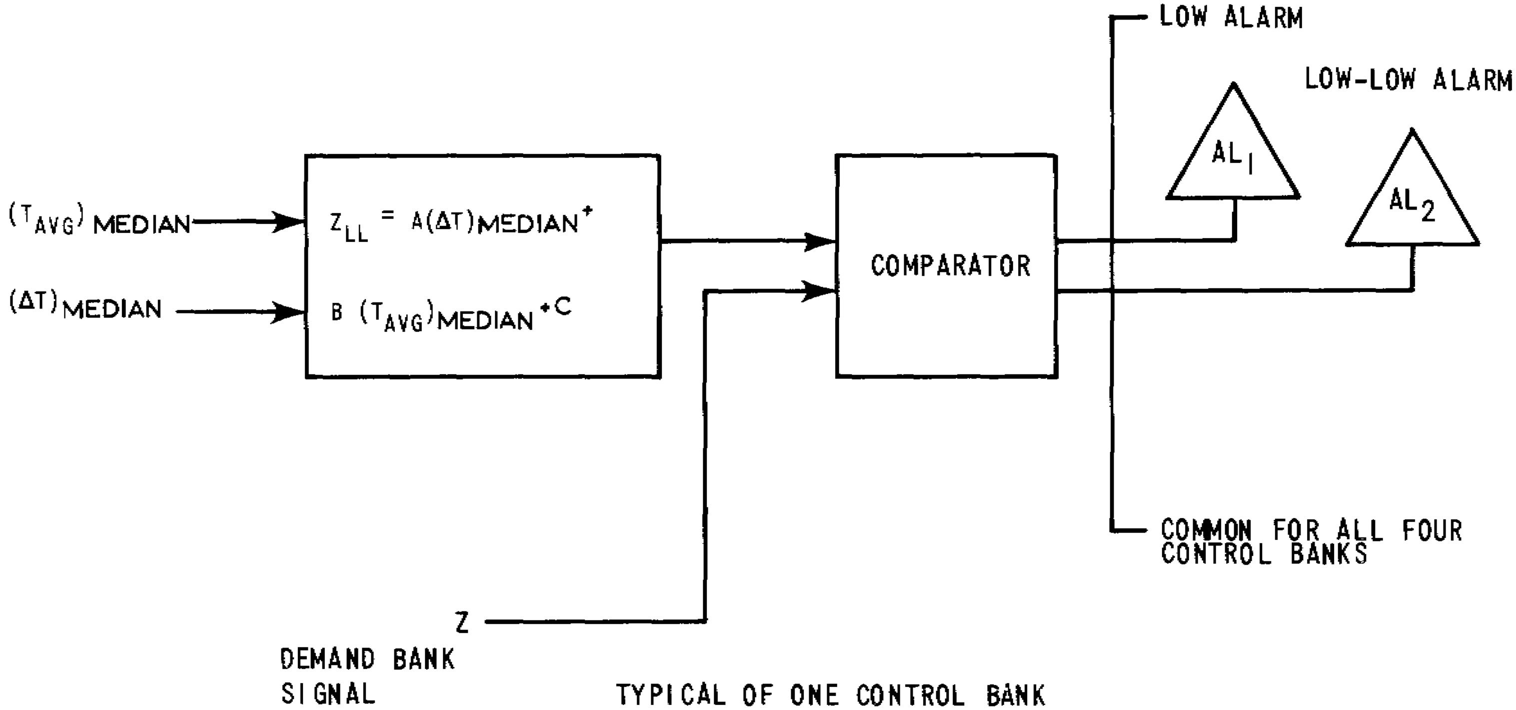
FIGURE 7.7-1

SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM

BEAVER VALLEY POWER STATION UNIT NO. 2

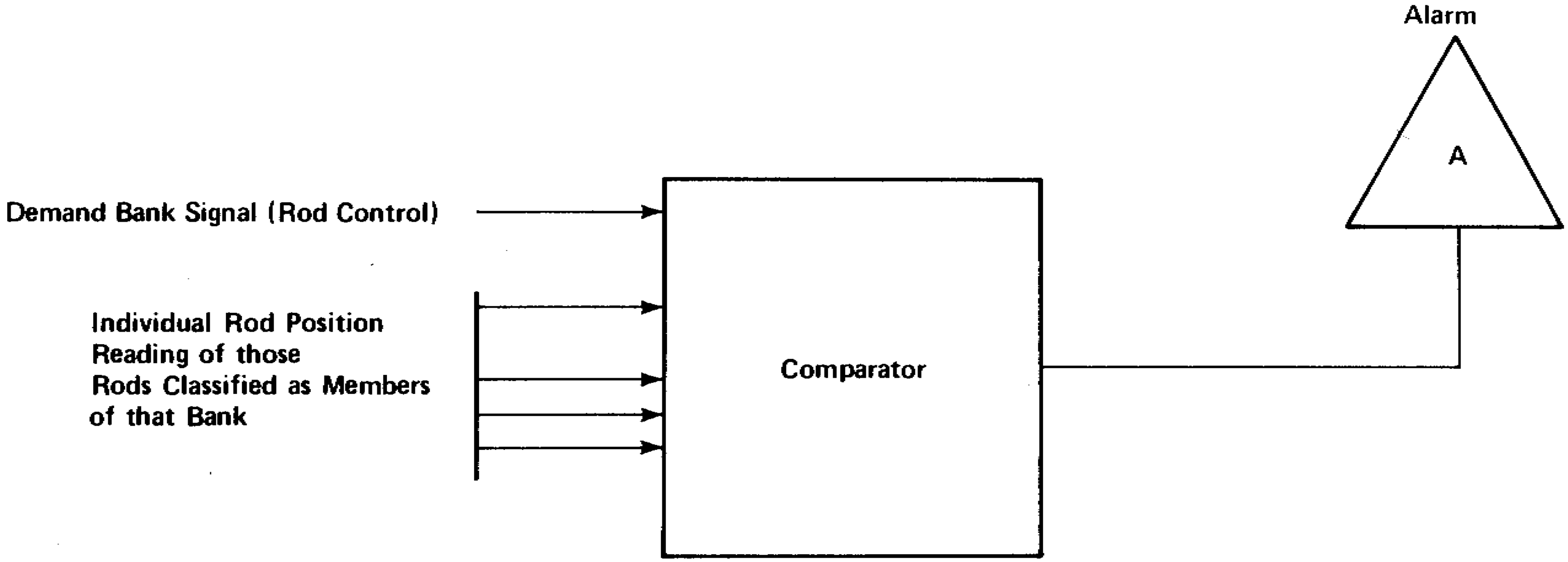
UPDATED FINAL SAFETY ANALYSIS REPORT

REV 3



NOTE: 1. ANALOG CIRCUITRY IS USED FOR THE COMPARATOR NETWORK.
2. COMPARISON IS DONE FOR ALL CONTROL BANKS

FIGURE 7.7-2
CONTROL BANK ROD INSERTION MONITOR
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



Note: 1. Digital of Analog Signals may be Used for the Comparator Computer Inputs.

2. The Comparator Will Energize the Alarm if There Exists a Position Difference Greater Than a Preset Limit Between Any Individual Rod and the Demand Bank Signal.

3. Comparison is Individually Done for All Control Banks.

FIGURE 7.7-3
ROD DEVIATION COMPARATOR
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

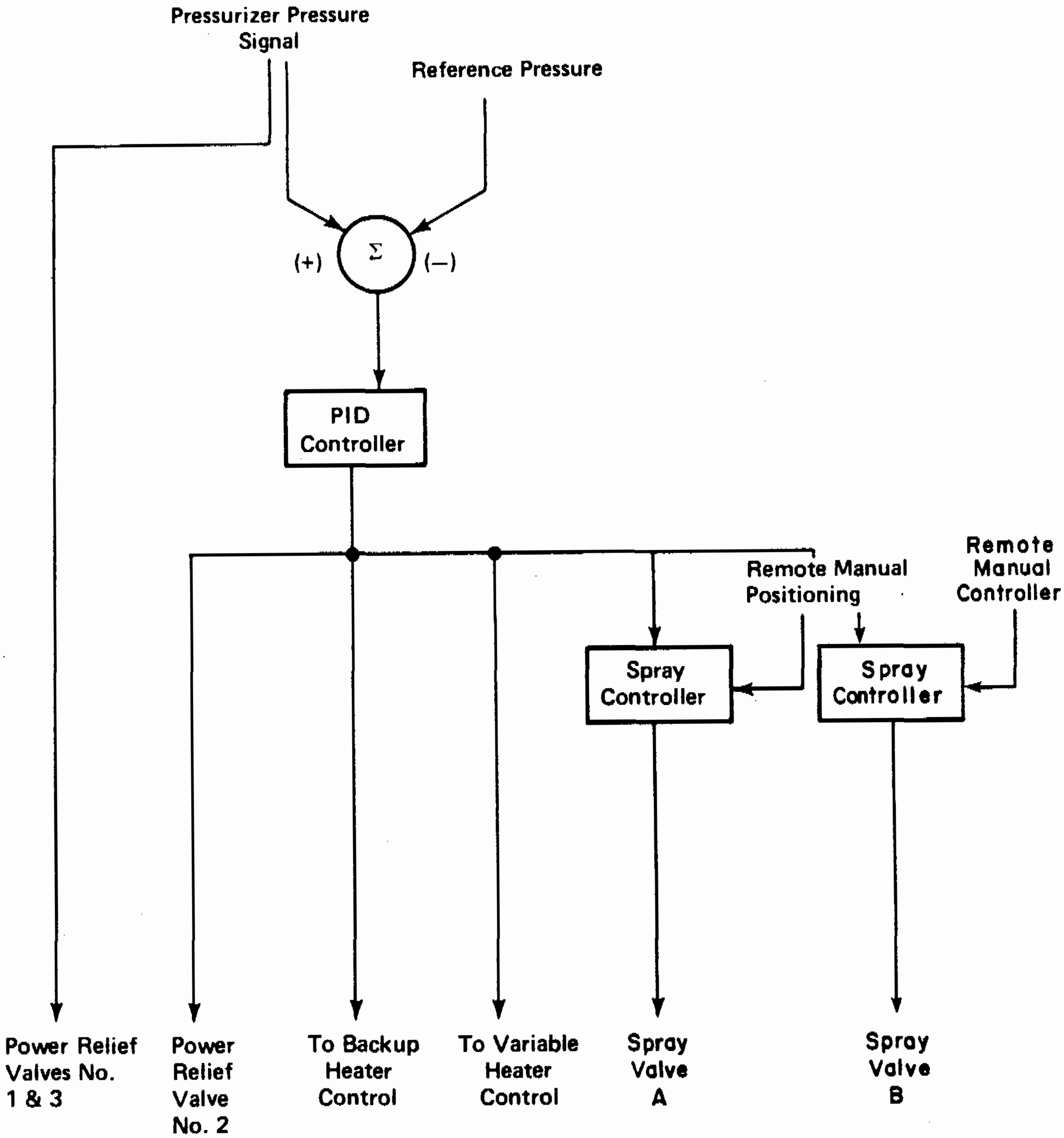


FIGURE 7.7-4

BLOCK DIAGRAM OF PRESSURIZER PRESSURE CONTROL SYSTEM

BEAVER VALLEY POWER STATION-UNIT 2

FINAL SAFETY ANALYSIS REPORT

REV 3

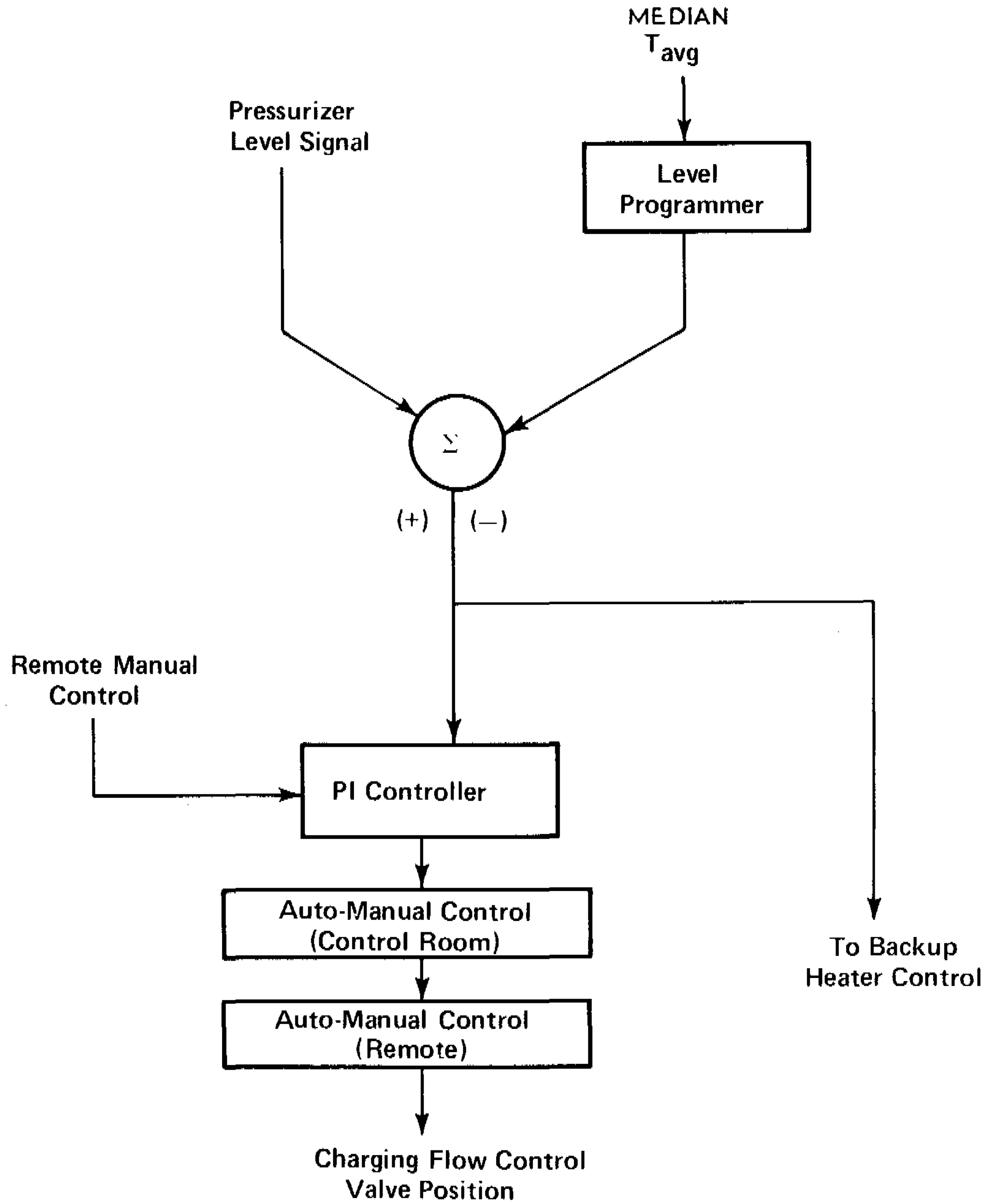


FIGURE 7.7-5
BLOCK DIAGRAM OF PRESSURIZER LEVEL CONTROL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 17

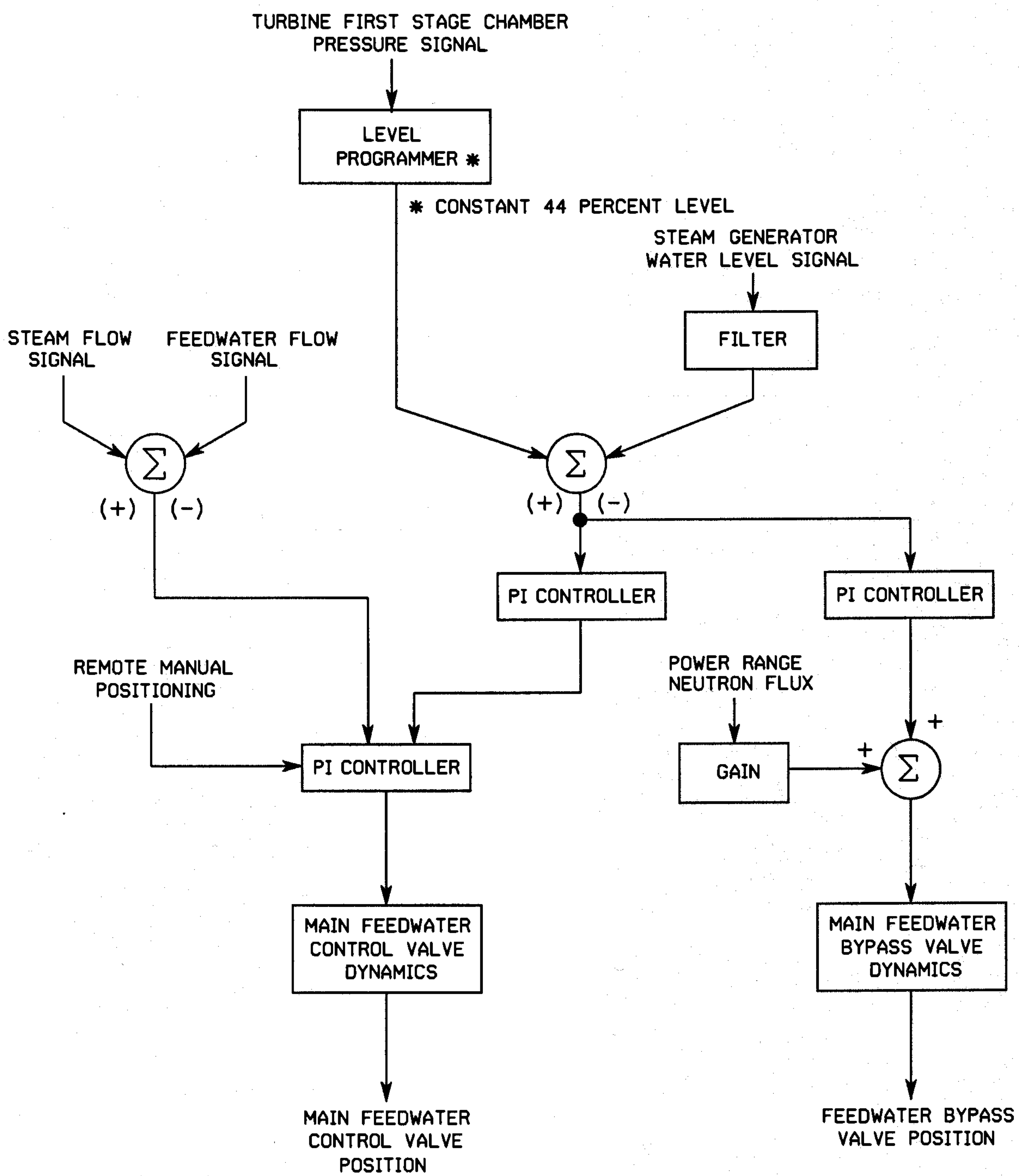
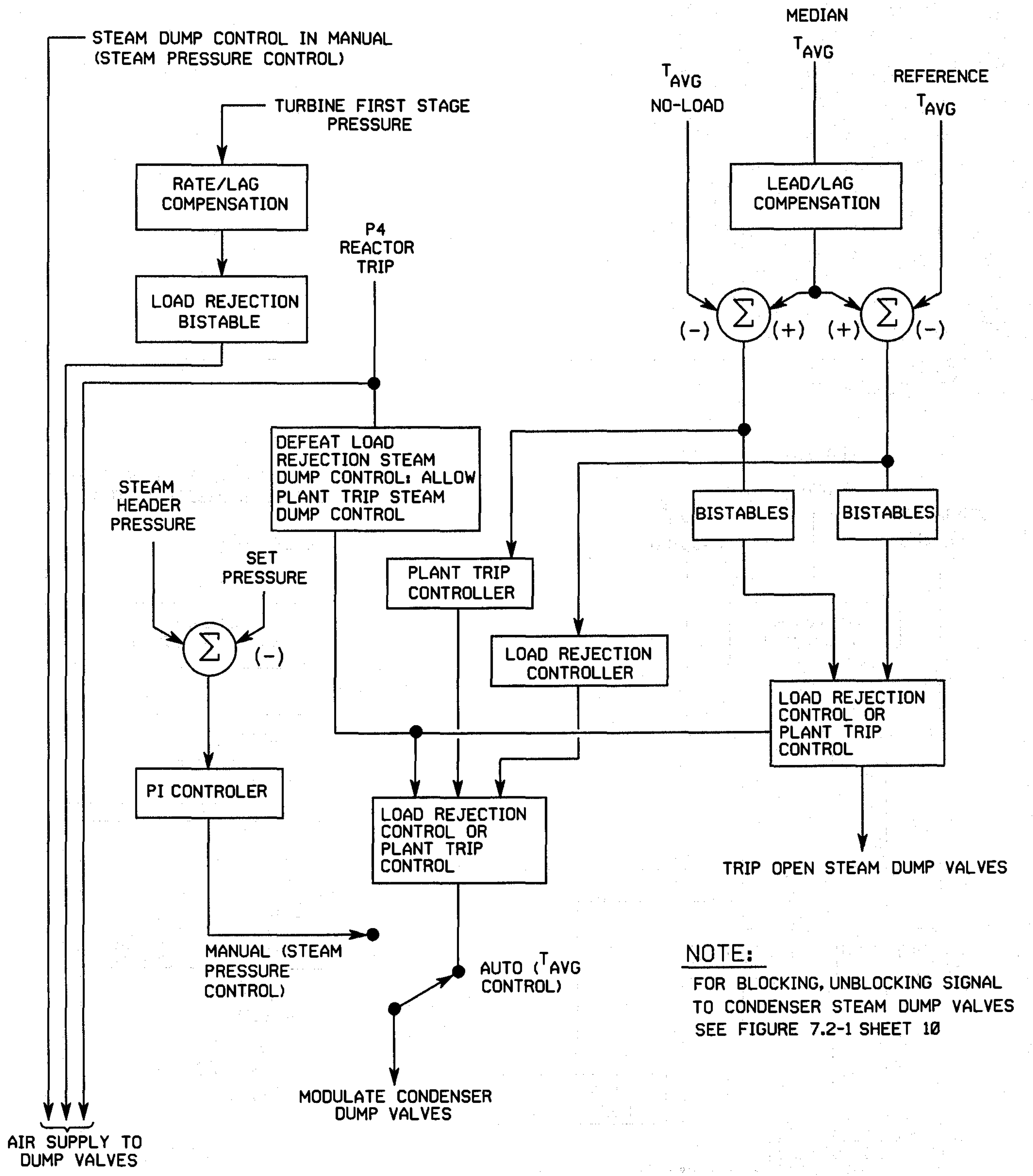


FIGURE 7.7-6

BLOCK DIAGRAM OF STEAM GENERATOR WATER LEVEL CONTROL SYSTEM

BEAVER VALLEY POWER STATION - UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT



NOTE:
FOR BLOCKING, UNBLOCKING SIGNAL TO CONDENSER STEAM DUMP VALVES SEE FIGURE 7.2-1 SHEET 10

FIGURE 7.7-7

BLOCK DIAGRAM OF STEAM DUMP CONTROL SYSTEM

BEAVER VALLEY POWER STATION - UNIT No.2
UPDATED FINAL SAFETY ANALYSIS REPORT

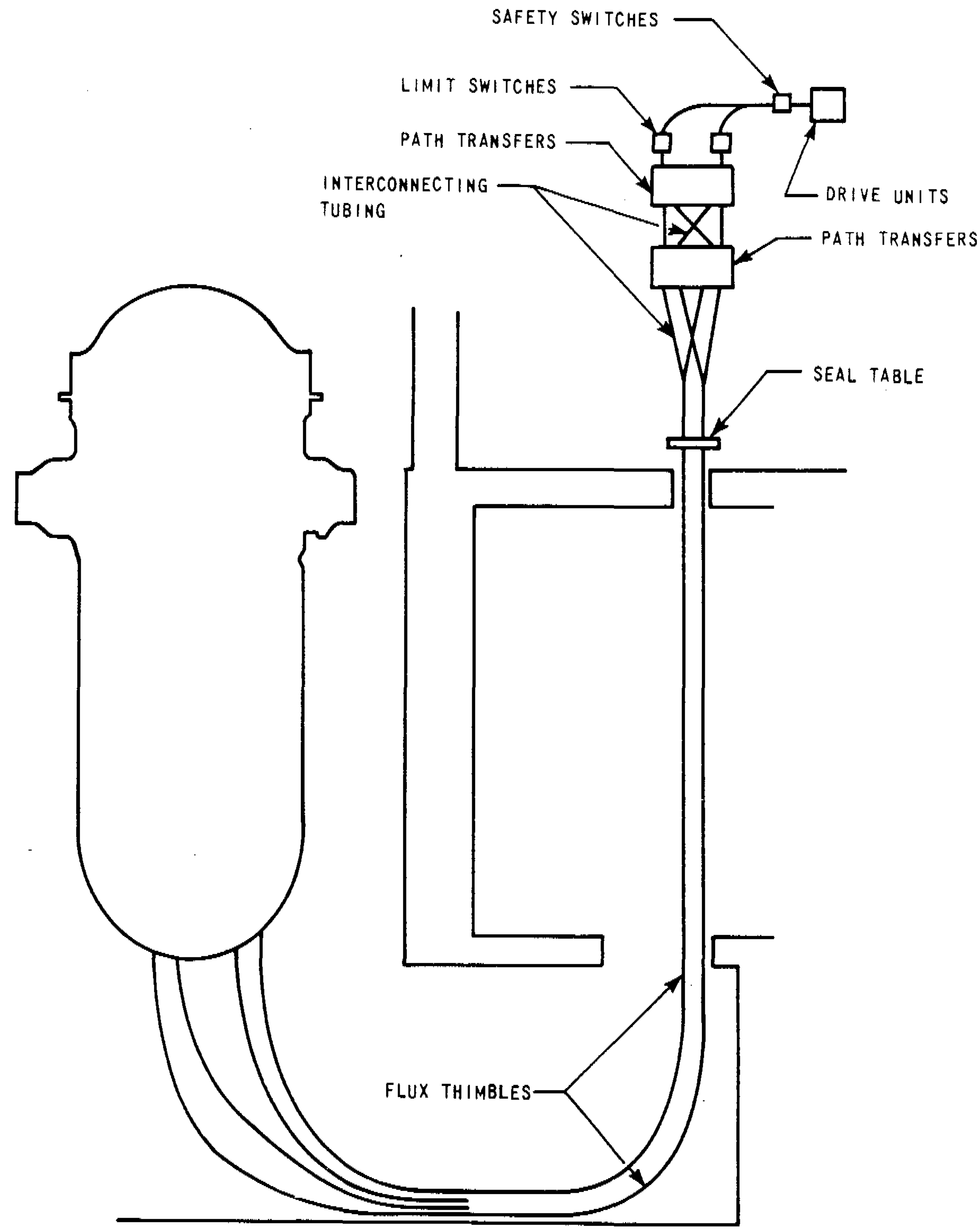


FIGURE 7.7-8
BASIC FLUX-MAPPING SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

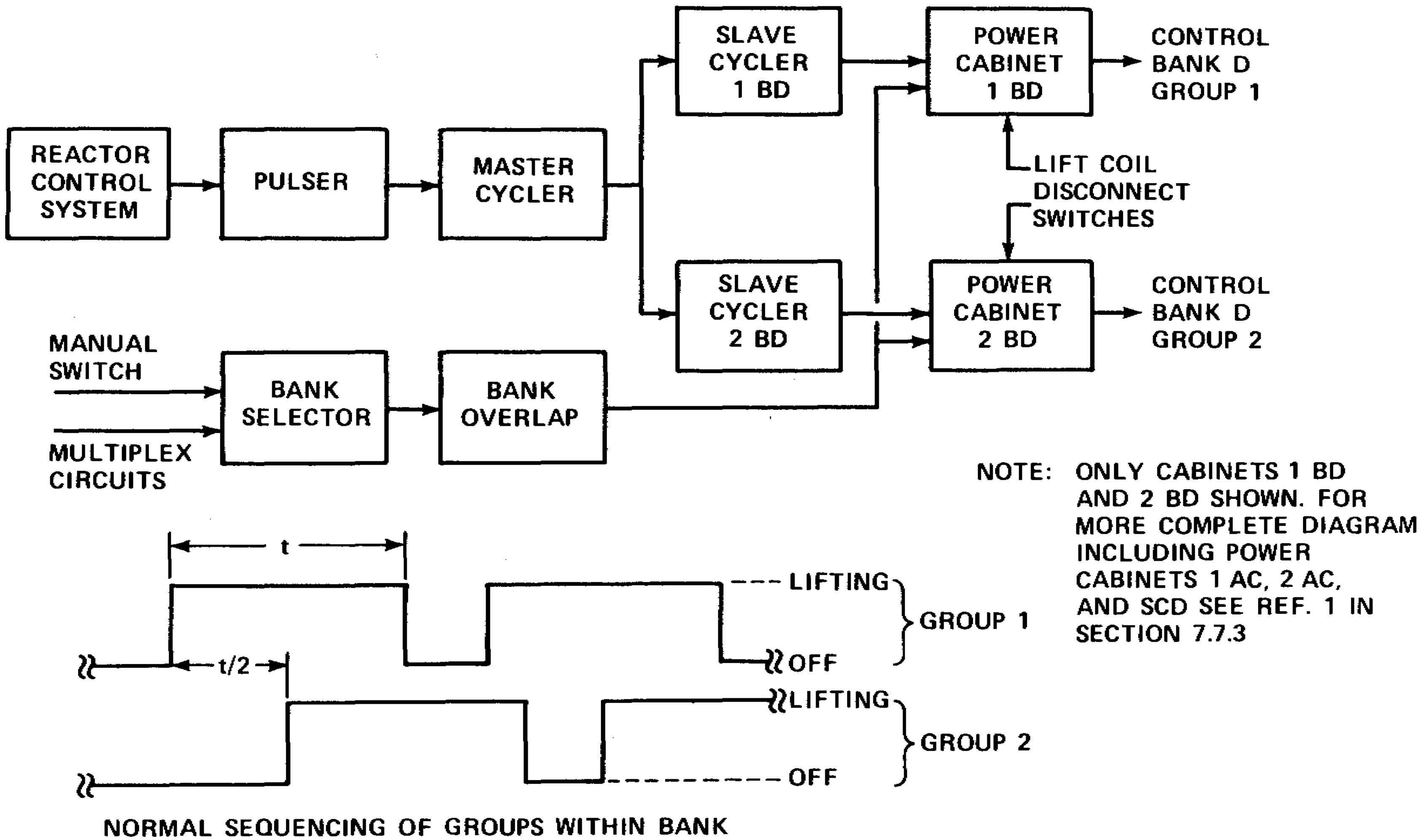


FIGURE 7.7-9
SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

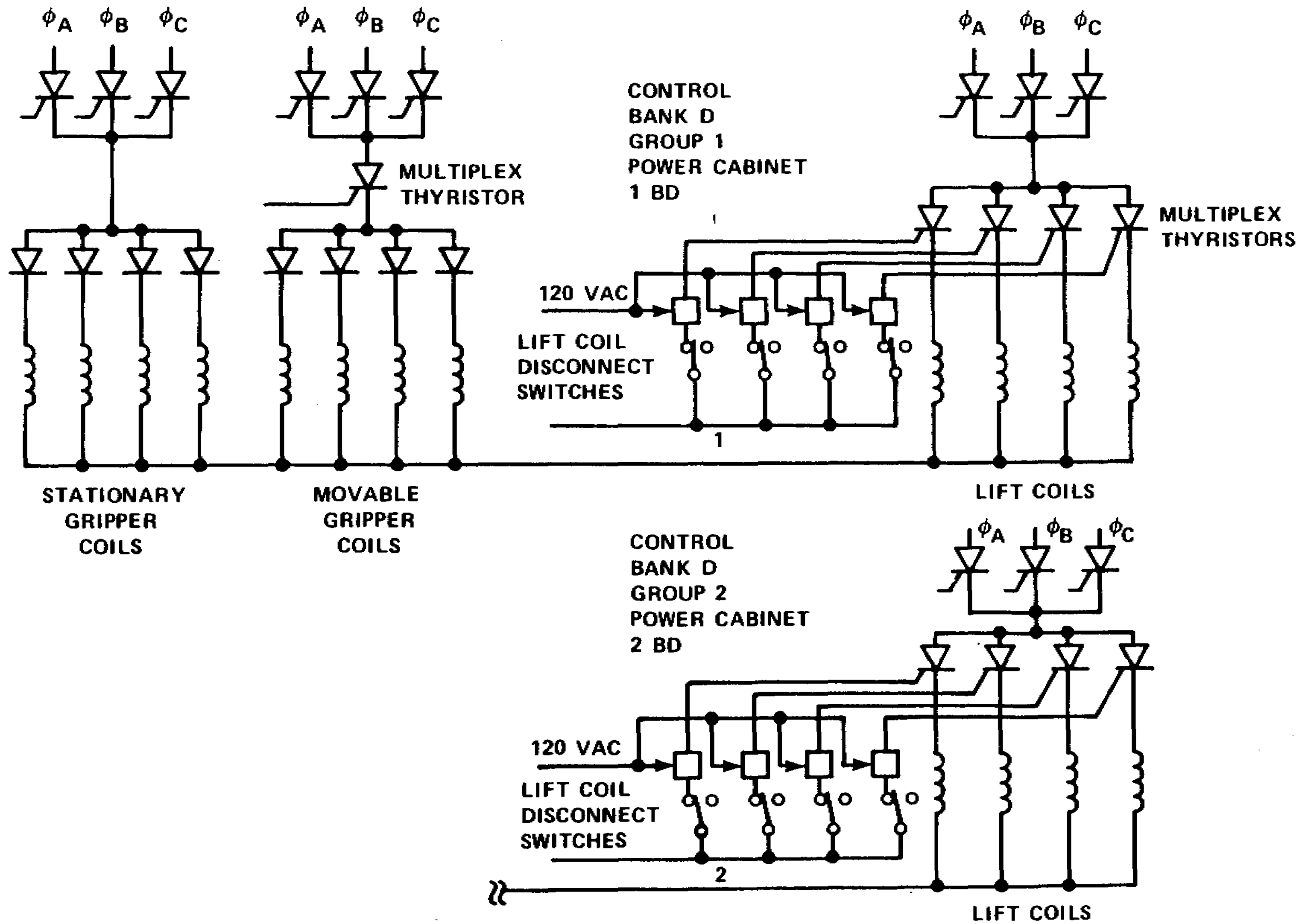


FIGURE 7.7-10
CONTROL BANK D PARTIAL SIMPLIFIED SCHEMATIC DIAGRAM POWER CABINETS 1BD & 2BD
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT