ATTACHMENT 4
Training Material on Diesel Generator Malfunctions

Contents

Exelon Generation.

Course/Program:	ILT/NLO/LORT	Module/LP ID:	LP85114
Title:	©CIRCUIT BREAKERS; 480 VOLT AND BELOW	Course Code:	N/A
Author:	B. D. Lewis	Revision/Date:	009 / 6/29/18
Prerequisites:	None	Revision By:	M. Beeler
Responsible Site	Clinton Power Station	Est. Teach Time:	3 hours

Qualified Nuclear Engineer Review (If applicable):	N/A	Date:	N/A
Training Supervision Review: (Print name / Signature)	R. J. Frederes /S/	Date:	07/03/18
Program Owner Approval: (Print name / Signature)	Richard Champley /S/	Date:	07/11/18

TABLE OF CONTENTS Pg. #

SRRS 3D.126/3D.111: Retain approved lessons for life of plant OR Life of Insurance Policy + 1 Yr for RP lesson plans. May be retained in department for two years, then forwarded to Records Management.

OBJECTIVES

The trainee shall:

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.1	Recall the purpose and design basis for Low Voltage Breakers while operating, or on an exam in accordance with the USAR and procedures/student text.	x	x	x	x	3
.1.2	Not Applicable.					
.1.3	Trace the control circuit for 480VAC Substation Breaker on the appropriate Electrical Schematic for opening & closing operation while operating the system, performing an out of service, or on an exam in accordance with the student text:	x	x	x	x	15
.1.4	Recall the function, theory of operation, interlocks, trips, power supplies and characteristics of the following Low Voltage System breakers and relate these items to local and remote operations while operating the system or on an exam in accordance with the student text.					
	.1 480v Substation K-Line Breakers	x	x	x	x	4, 16, 17
	.2 480v MCC Molded Case Breakers	x	x	x	x	10, 17
	.3 220/120v Distribution Panel Breakers	x	x	x	x	13

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.5	Recall the physical location to access and operate the following Low Voltage System breakers and the associated local/remote control devices during normal system operation, emergency plant conditions, or on a written exam in accordance with station procedures:					
	.1 480v Substation K-Line Breakers	x	x	x	x	6, 8, 9
	.2 480v MCC Molded Case Breakers	x	x	x	x	11, 12
	.3 220/120v Distribution Panel Breakers	x	x	x	x	13
.1.6	Given a status of the following Low Voltage System breakers, recall the physical location of local indicators and describe the expected indication for the status while operating the system, during abnormal conditions, or on an exam in accordance with the student text.					
	.1 480v Substation K-Line Breakers	x	x	x	x	6, 8, 9
	.2 480v MCC Molded Case Breakers	x	x	x	x	11, 12
	.3 220/120v Distribution Panel Breakers	x	x	x	x	13
.1.7	Not Applicable. N-CL-OPS-262001					
.1.8	Not Applicable. N-CL-OPS-262001					
.1.9	Not Applicable.					
.1.10	Not Applicable.					
.1.11	Recall the conditions/setpoints and associated automatic actions for the following significant annunciators while operating the Low Voltage Breaker System, or on an exam in accordance with annunciator response procedures.					
	.1 Loss of DC Control Power	x	x	x	x	17

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.12	Recall the systems that support the Low Voltage Breakers and the nature of the support provided while operating the system, or on an exam in accordance with student text.					
	.1 DC Electrical Distribution	x	x	x	x	18
.1.13	Recall the systems that are supported/influenced by the Low Voltage breakers and the nature of the support provided while operating the system, or on an exam in accordance with student text.					
	.1 AC Electrical Distribution	x	x	x	x	18
.1.14	Demonstrate an understanding of when precautions and limitations for Low Voltage Breaker operations 1) Are bypassed during unusual plant conditions when given an operating mode and plant parameters; or 2) Are applied during use of station procedures. Recall the reasons for the precautions and limitations while operating the system or on an exam in accordance with station procedures.	x	x	x	x	13, 21, 22, 23, 24, 25, 26, 27, 28
.1.15	Given various plant conditions, predict how the Low Voltage Breaker operation will respond to various system or component failures while operating the system or on an exam in accordance with student text.	x	x	x	x	11, 12, 13, 16, 17,24, 28, 28
.1.16	Given a copy of Technical Specifications, Operational Requirements Manual, ODCM, various Low Voltage Breaker and plant conditions, apply them to determine if LCOs have been met or exceeded, and identify the required actions in accordance with above references.	x	x		x	19, 20

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.17	Given key system parameters and various plant conditions, recall Limiting Safety System Settings, One Hour or less LCO actions statements while operating the Low Voltage breakers or on an exam in accordance with Technical Specifications.	x	x		x	19
.1.18	Given the following plant conditions recall the plant actions that are required while operating Low Voltage Breakers or on an exam in accordance with student text.					
	.1 Manually Trip a 480v Substation K-Line Breakers	x	x	x	x	22
	.2 Manually Close a 480v Substation K-Line Breakers	x	x	x	x	22
	.3 Manual Spring Charging 480v Substation K-Line Breakers	x	x	x	x	22
	.4 Rackout 480v Substation K-Line Breakers to disconnected position	x	x	x	x	22
	.5 Racking 480v Substation K-Line Breakers to the connected position.	x	x	x	x	23
	.6 Emergency operation of MCC 480V Molded Case breaker	x	x	x	x	25

Evaluation Method & Passing Criteria: WRITTEN EXAMINATION WITH SCORE ≥ 80%.

References

CPS No. 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program.

CPS No. 3502.01, 480 VAC Distribution

CPS No. 3507.01, Station Lighting and Low Voltage System

CPS No. 3515.01, Operation of 6900/4160/480V Circuit Breakers

CPS No. OP-CL-108-101-1001 General Equipment Operating Requirements

AC Electric Distribution System Description

CPS Schematic Diagram, E02-1AP99 Sheet 089
E02-1AP03-001

Instruction Manual, ITE MCC. K2976-0001

Instruction Manual, K2801-0158 (HPCS MCC, GE)

Instruction Manual, Brown Boveri ITE Switchgear, K2974-0004

CPS Condition Report CR-1-83-06-002

Instruction Manual IB-9.1.7-22, Powershield Solid State Trip Device (Gray Case) (In K2974-0004)

SA-AA-129, Electrical Safety

SOER 10-2, Engaged, Thinking Organizations

INPO 15-004, Operations Fundamentals

Commitments: None

LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
0	10/13/95	Initial Development
1	09/20/02	Update to new Exelon format per TQ-AA-210-3201 R00 Lesson Plan Template (Portrait). Revised and updated objectives. Resolved missing KA links to lesson plan. Reorganized overall lesson plan correcting and clarifying technical information. Added photos.
2	09/22/04	Incorporated TRACER # 2004-07-0058A. This added OE 18132 to OPEX.
2a	3/22/06	Change reference on page 19 B.1. From SSS 17 to SA-CL-129 Change 2.C on page 24 from SSS 17 to SA-CL-129 Add SA-CL-129, Electrical Safety, to the list of references on page viii Add figures for MCCB bucket stabs
3	10/14/06	Incorporated TRACER #2006-05-0129A.
4	02/23/07	Incorporated TRACER #2006-05-0063A (Minor Revision).
5	04/05/10	Incorporated TRACER # 2008-05-0122A and 2009-02-0063A. Changed all references from SA-CL-129 to SA-AA-129. Changed references from "ITE Model K Type Gould or ABB breakers" to "K-Line breakers". Added MCCB reference to include newer Siemens ED breakers. Updated LP references. Relabled Figure 6 due to confusing arrow placement. Removed Figure 6b, no value added.
6	11/27/12	Incorporated 011853410-69, correcting Objectives that are listed as N/A have designations for SRO/RO/NLO/STA. Corrected the objective numbering format in the Activities/Notes region. Corrected the page number to objective relationship. Added SOER 10-2, Engaged, Thinking Organizations. Added detail to several Interim Summary questions. Added HU tools enforcement actions.
7	10/11/17	Added discussion of additional force needed to rack high current breakers in and out, SOAR discussion, and editorial changes to correct grammatical/format errors.
8	4/16/18	Added Instructor notes on Robinson Event, SOER 10-2.
9	6/29/18	Clarified breaker reset conditions under Operational Characteristics.

Instructional Methods:

- lecture/discussion
- Lab (optional)

Media:

- White board
- Trainee text
- Additional copies of K-Line Breaker schematic
- Breaker Lab (optional)

I. Introduction

Low Voltage circuit breakers are the primary components of the 480V Unit Substations and Motor Control Centers of the Auxiliary Power (AP) Distribution system. The AP system includes twenty-six 480V Unit Substations which receive power from the 6900V and 4160V AC Distribution System through step down transformers. Eighteen Non Divisional Unit Subs are fed from 6900V distribution and six Non Divisional Unit Subs are fed from 4160V distribution. Division 1 and Division 2 both support one Unit Substation.

480 VAC Unit Substations typically supply motors between 250 and 50 horsepower either directly or through MCC. Unit Subs distribute power through 111 Motor Control Centers (MCC), 2 Hydrogen Igniter Panels, and risers located throughout the plant. Division 3 is supplied by three 480v MCC's, without the use of a Unit Sub, through one common 4.16kV to 480 volt transformer.

Low Voltage System, 208/120V and 240/120V AC, is supplied from Motor Control Center Distribution Panels and Station Lighting Circuits.

The 480V and below Circuit Breakers provide selective tripping protection for the Auxiliary Power and Low Voltage Distribution Systems. Substations use an ABB/Gould K-Line breaker for the main feed and load distribution. Some Unit Substation breakers can be controlled remotely; other Unit Substation breakers can only be operated manually.

Most 480V loads including pumps, motor driven valves, fans heaters and low voltage distribution panels are powered through a Motor Control Center (MCC) using ITE/GOULD HE series or newer Seimens ED series molded case circuit breakers.

Understanding the operation of the low voltage breakers is important to the reliable and safe operation of the plant. Failure to properly return a breaker to service has impacted the availability or operability of plant equipment as well as resulted in serious personal injury and fatalities.

Because of the operating experience involving failures of molded case circuit breakers while using them for personnel protection on tagouts, operators now verify the associated circuits de-energized using EMF or voltage instruments. The breaker operation and resulting position indication cannot be relied upon to ensure that the breaker was successfully opened.

A. Overview of training session

This subject will be presented in a 3-hour classroom session, which includes:

- Lecture
- Print reading exercise
- Visit the Maintenance lab to inspect the mockups of the low voltage breakers. (Optional)

The Objectives, to be discussed later in detail, basically includes the following:

- Breaker operations and precautions
- Interlocks and purpose
- Electrical protection features
- Methods for control breakers and power to loads.

Evaluation:

Knowledge of objectives will be evaluated with a weekly and a comprehensive written examination at the end of the systems training requiring a minimum score of 80%.

At the start of class, if appropriate, introduce yourself and establish rapport with the class.

II. System Purpose

A. System Purpose

[.1.1]

The 480V and below Circuit Breakers are special purpose switches used to control the flow of large currents during normal operations. Specific purposes are as follows:

- Interruption of fault currents and overload conditions
- Suppression of the main line contact arc when opening.
- Containment penetration protection
- Remote control of 480V loads through inline contactors
- Load shedding devices when shunt tripped by LOCA or other accident signal

B. Design Basis

1. Support power circuit operation by providing protective devices that will accomplish the following:
   a. Disconnect circuit faults from power sources,
   b. Disconnect the faulted component with minimum disturbance to the unfaulted portions of the system,
   c. Protect the system from false disconnecting operations for any anticipated normal event.
2. Devices fed from 480-V unit substations must have instantaneous and time overcurrent protection.
3. Motor control center buckets are to be equipped with thermal overloads to protect the equipment being supplied. Overload protection of Class 1E motor-operated valves will be continuously bypassed with the exception that it may be placed into service for short periods of time during valve maintenance, testing, and repositioning during normal plant operation.

III. SYSTEM FLOWPATH(S)

[.1.4.1] **Figure 1**

The flow paths associated with 480V Distribution and below are addressed in either the Auxiliary Power N-CL-OPS-262001 or Lighting and Low Voltage Electrical Power N-CL-OPS-262006. This lesson plan provides a generic discussion of the breakers used in these systems. Specific application of these components can also be found in N-CL-OPS-262001 or N-CL-OPS-262006.

IV. Components

A. 480VAC Substation Air Circuit Breakers (K-Line)

1. K-Line breakers are used in the 480V Substations for the main feed from the 6900 or 4160 to 480V transformers, supplying MCCs, supplying Risers, and cross ties to other Substations. Both manual and remotely operated electrically controlled breakers are used in the 480V Substations.

2. The circuit breaker continuous current rating is established by the breaker frame's physical size. The main feeds use a K-1600S breaker, which is rated for 1600 amp service. The "S" denotes that a Powershield solid-state overcurrent trip device is used. The other services use a K-600S, which is rated for 600-amp service. Exceeding breaker continuous current ratings raises circuit breaker temperature beyond design limits reducing breaker operating life.

3. The circuit breaker nameplate contains information regarding the manufacturer's name and address, type of circuit breaker design, serial number of circuit breaker, continuous current rating of frame size, short circuit current rating at rated voltages, frequency, short time current.

4. Most 480V loads are fed from a MCC; however, a few large loads such a major building cranes and elevators are supplied directly from the Substation through a K-Line breaker.

5. K-Line Breakers can be horizontally drawn in or out of an enclosed steel Substation cubical by levering the breaker on a cam operator using a threaded lead-screw. As the breaker is slid into the cubical, DC control power and then 480V power is connected to the breaker through "stabs" located in the back of the breaker. A pair of 480VAC stabs is provided for each phase. 480V stabs are referred to as the Primary Contactors and the DC control power stabs are the Secondary Contactors. Internal to the circuit breaker power flows from the supply side coupling stabs, through the breaker main and arcing contacts, and then back through the load side coupling stabs.

Figure 2

6. The TSC switchgear in the NTD building (OCA) utilizes Brown Boveri Electric circuit breakers. These breakers perform the same function as K-Line Breakers in the plant and as such will not be discussed in detail here. There are however differences in the physical operation of these breakers. Refer to CPS 3515.01, Operation of

6900/4160/480V Circuit Breakers for detailed operating instructions.

7. Arc Suppression

   a. When an electrical circuit is opened, the normal path for current flow is broken. Current will attempt to continue to flow through the circuit by arcing across the interrupting gap. The collapsing field of an inductive load will aid this current flow. Current flowing across the interrupting gap heats and ionizes the air within the gap. As current flows through the interrupting gap the air heats up and ionizes causing a reduction in resistance allowing a higher current flow. Circuit breakers are designed to rapidly and reliably interrupt current flow and extinguish arc formation before the current flow can become damaging.

   b. All of the 480V and below circuit breakers at CPS employ spring actuated interrupting contacts and diffused air gaps to dissipate the resulting arc when the circuit breaker opens.

8. Common Face Plate Controls: Electrical and Manually Operated K-Line Circuit Breakers

   [.1.5.1] [.1.6.1] Figure 3 & 4

   The K-Line K-1600S and K-600S type circuit breakers are provided with an extendible "escutcheon" face plate. The faceplate provides a central area for the controls, which are mounted directly on the circuit breaker. The common controls for manually operated breakers and those with capability for remote electrical operation are as follows:

   a. Manual Trip Button that when depressed will locally trip the breaker open.

   b. Circuit breaker "OPEN" or "CLOSED" direct indication of the circuit breaker contacts

   c. Automatic Trip Indicator which, indicates actuation of the electro-mechanical overcurrent trip device. The white plastic trip indicator protrudes approximately 1/2 inch from the faceplate indicates an overcurrent trip occurs.

      1) The automatic trip indicator has to be manually reset after a trip by pushing it back into the normal latch position.

2) Remote trip alarm indication is obtained from the Trip Indicator device.

3) A provision is provided in the Trip Indicator device for mechanically preventing re-closing of the breaker until it is reset. This feature is used in a few cases at CPS. If a lockout is desired it is typically accomplished within the breaker control circuit.

d. Racking Mechanism Shutter that must be raised to insert the racking tool, which is a crank used to move the breaker to the CONNECTED, TEST or DISCONNECTED (Racked out) position. The breaker can also be withdrawn from the cubical. The breaker is disconnected from the 480V stabs as it is backed into the TEST position. In the TEST position, the DC Control Power is connected. In the DISCONNECTED position both 480V and DC Control Power stabs are disconnected. Refer to Attachment C for definitions of breaker statuses.

e. Padlocking Device to lock the breaker in the trip-free position.

1) This is accomplished by depressing the Manual Trip Button and pulling out the vertical locking plate. A pad lock can be inserted in the slot that is now exposed which holds the plate in the extended position. In this position, the mechanism is maintained trip free condition and the contacter arm cannot be moved to the closed position.

2) With the padlock engaged the tripped breaker cannot be moved from the existing position (CONNECTED, TEST or DISCONNECTED).

f. Closing Electrically Operated breakers can be accomplished locally using the CLOSE Button on the escutcheon plate. Manual breakers are closed using the T-Handle on the front of the breaker. It is preferable to operate Electrically Operated breakers from the remote controller.

9. Electrically Operated K-Line Circuit Breakers

[.1.5.1] [.1.6.1] Figure 3

Electrically Operated K-Line circuit breakers are controlled by a device located in the low left section of the breaker cubical. The control device contains three electrical components, the limit switch (LS), the lockout relay (52Y) and the latch release relay (52X) (closing coil). The lockout relay ensures that the close contacts are opened before the breaker can be reclosed preventing a rapid succession of attempted closings (pumping).

a. Electrically Operated Substation breakers are controlled using 125 VDC control power. The control power is fused at the input to the Substation and routed to the individual breaker cubical.

b. When a local or remote control device provides a “close” command the spring release coil is energized to allow the two breaker Closing Springs to close the breaker. A “trip” command energizes the trip coils to release the two Opening Springs, to open the breaker.

1) The two Closing Springs are automatically charged whenever DC Control Power is available to the electric charging motor. During the closing operation the two closing springs supply the power that both closes the breaker and also charge the two Opening Springs as the breaker closes. This ensures that a closed breaker has two fully charged springs available for tripping/opening operations.

2) Indication of the status of the Closing Spring is visible through an aperture on the escutcheon plate of Electrically Controlled breakers. ("SPRINGS CHARGED" and "SPRINGS UNCHARGED").

3) The Closing Springs are automatically discharged when racking the circuit breaker from the DISCONNECTED (rackout) position. As soon as DC Control power is made up when racking the breaker in, the Closing Springs recharge (at the TEST position).

4) The Motor Disconnect Switch, mounted on the escutcheon plate, is normally used when racking out the breakers for maintenance or a tagout to prevent automatic recharging of the Closing Springs. It is a double pole, single-throw toggle switch connected in series in the charging motor circuit.

5) Non-routine operations that would typically be performed by electricians on Electrically operated breakers included manually charging the Closing Spring using a special tool. Also a lever on the escutcheon plate of electrically operated circuit breakers provides a means of closing the breaker without control power. Lifting the lever allows using a special tool to close the breaker by manually releasing the closing spring release mechanism.

10. Manually Operated K-Line Circuit Breakers

[.1.5.1] [.1.6.1] Figure 4

a. Manually Operated K-Line circuit breakers have a Closing Spring "T-handle" to manually charge the breaker Closing Springs and close the breaker. In one continuous downward pull of the handle the two Closing Springs are charged, and near the end of the stroke are discharged to fast close the circuit breaker.

b. During the closing stroke, the two Opening Springs are charged. The breaker may be opened by manually actuating the opening spring release mechanism (manual TRIP Button) with the controls on the front of the breaker or by an automatic trip such as an electrical fault.

c. The Manually Operated K-Line breaker does <u>not</u> include the electrical CLOSE pushbutton switch, motor disconnect switch, manual close lever, spring charge indicator or maintenance handle (or manual spring charging handle).

11. Racking Mechanism for K-Line Circuit Breakers

[.1.5.1] Figure 1

a. The racking mechanism may be used to move the circuit breaker to any one of its three breaker positions ("CONNECTED", "TEST" or "DISCONNECTED"). All of these positions are attainable with the cubicle door closed. The racking shutter which must be lifted to gain access to the racking mechanism.

b. The breaker is interlocked with the shutter position as follows:

1) The circuit breaker contacts must be open before the shutter may be lifted.

2) The circuit breaker cannot be closed when the shutter is open.

3) The shutter is locked closed when the breaker locking hasp is being pulled out and padlocked in the TRIP position.

4) The racking shutter can be opened or closed in the TEST position. In the DISCONNECTED position, the racking shutter cannot be closed.

c. There are indicating lines to show when the breaker is in the either the "TEST" or "DISCONNECTED" positions.

B. 480VAC MCC Distribution Breakers

[.1.4.2]

1. 480VAC MCC Distribution uses ITE/Gould or Siemens molded case circuit breakers (MCCBs) and associated components housed in a “bucket” to supply individual loads. MCC distribution is used for small loads that are 50 horsepower and below.

2. Power enters the 480 VAC MCC through the top of the MCC. Each MCC has a 3 phase horizontal bus section capable of carrying between 600 and 3000 amps, and 3 phase vertical bus sections capable of carrying between 300 and 600 amps. The current carrying capability of individual busses depends on the specific size bus bars installed.

3. The MCC “buckets” have three stab connectors on the back, which clips onto the vertical MCC buswork providing power to the MCCB. When the MCCB is closed power is available to supply downstream loads such as the control circuit transformer and the motor starter or motor open/closed reversing contactor depending upon the application. Removal of a MCC Molded Case breaker and/or its associated components from the MCC usually entails removal of the “bucket”. They do not rack out like the K-Line circuit breakers.

4. The breakers are operated through a linkage by rotating a control switch on the front panel of the cubical with ON, TRIP, and OFF positions. The breaker is interlocked to only operate using this switch when to panel door is closed. The operation of the breaker through the linkage is not always reliable requiring independent verification that the breaker opened when the breaker is used as a tagout boundary. The verification is satisfied by performing a "zero voltage" or "live-dead-live check" downstream of the breaker.

[.1.5.2] [.1.6.2] [.1.15] Figure 5

5. MCC control power is generated inside each MCC breaker compartment or bucket by a 480-120 VAC resin encapsulated transformer in most cases. Power to this transformer taps off of the 480 VAC power leads on the source side of the starter/contactor. In some special cases MCC control power is DC. Examples are Turbine Building Closed Cooling Water (WT) and Stator Cooling Water (GC) Pumps.

   a. With the MCC Molded Case breaker closed, application of 480VAC to the load is controlled by the starter/contactor.

   b. Control power is used in conjunction with switches and interlocking contacts to energize the following:

      - Motor starter contactor (small pumps and fans),
      - Reversing contactor (motor operated valves),
      - Indicating lights, and
      - Overload, alarm and other auxiliary relays

6. Motor Starters & Reversing Contactors

   a. Motor starters and reversing contactors are electrically controlled relays used to control loads less than 50 horsepower. Contactors energize to allow line current to flow to the load. Motor starters are single, three phase, contactors used to control to power small pumps and fans.

b. Reversing contactors are dual (open/MO or closed/MC) contactors typically used to control motor operated valve (MOV) actuators. Only one contactor (open or close) is energized at a time. Reversing contactors are mechanically and electrically prevented from energizing both contactors simultaneously to prevent damaging the load.

7. Overload Protection

[.1.15]

a. Molded Case ITE/GOULD or Seimens circuit breakers are provided with thermal-magnetic trip mechanisms. Thermal-magnetic trip mechanisms are utilized to protect the power source from long term low level (thermal) or instantaneous (magnetic) fault conditions.

1) Circuit Breaker magnetic devices uses magnetic tripping coils which actuates the breaker opening spring, as EMF increases, to release the tripping mechanism.

[.1.5.2] [.1.6.2]

2) Circuit Breaker thermal devices use a bimetallic strip and the heating effect of current passing through the breaker to release the tripping mechanism.

3) A Magnetic or Thermal trip condition is indicated by the local control switch in the TRIPPED position, loose between the ON and OFF positions.

4) A tripped MCC breaker (magnetic or thermal) may be reset by turning the local control switch past OFF to the RESET position, and then back to ON.

b. Additionally, a thermal overload device is attached to the load side of the motor contactor(s). MCC bucket thermal overload devices typically utilize a "solder pot" type sensing device.

1) The current to the load passes through the overload heaters. Excess current increases the heat felt by the sensing element. When the heat generated by the excess current is sufficient, the solder in the "solder pot" melts, allowing the spring to force the overload contacts open. When the overload contacts open, this interrupts power to the starter/contactor(s) and the load deenergizes.

2) There is a thermal overload contact and heater for each phase on the load side of the starter/contactor.

Adjustable overload trip settings (85, 100, and 115%) are available on each individual overload phase.	
3) Depressing the RED overload reset pushbutton on the front of the cubical resets the Thermal Overloads.	**Figure 5 & 6**
4) The RED button on the door depresses the WHITE reset plungers on each phase, inside the bucket. Be careful that the plunger does not stick in the depressed condition.	**[.1.14]**
C. 120VAC Distribution	**[.1.4.3] [.1.5.3] [.1.6.3] [.1.15]**
The 120 VAC distribution panel beakers are thermally actuated molded case circuit breakers similar to but smaller than the 480 VAC MCC breakers. When a 208/120 VAC distribution panel breaker trips the local breaker control switch will be loose between the OFF and ON positions. To reset a tripped breaker take the local breaker control switch to the OFF and back to the ON position.	
Interim Summary	
1. Which applications are K-Line breakers used?	**1.**
2. What faceplate controls are on Manually Operated K-Line breakers?	
3. What faceplate controls are on Electrically Operated K-Line breakers?	
4. How do you pad lock K-Line breakers?	
5. What controls the charging spring and charging motor operation?	
6. Describe closing sequence on a Manually Operated K-line breaker.	

6.

Content/Skills	7Activities/Notes
7. What controls the operation of loads (pump, MOV) fed by a molded case breaker? 8. What type of protection is provided on molded case breakers?	8.

V. Controls/Instrumentation/Power Supplies

A. K-Line Circuit Breaker Control

[.1.3] Figure 7

1. The sample schematic of the control circuit of an ABB/Gould K-Line circuit breaker is used to illustrate the basic breaker operation. Open/closed control input is represented by a single set of contacts as CS/C (close) and CS/T (trip). Depending on the specific application the input control scheme will vary. The schematic shows the breaker in an open condition with the closing springs uncharged, the control power source energized, and the Motor Disconnect Switch (MDS) closed. The following items describe the breaker operation.

    a. Immediately upon availability of control power, the spring charging motor (M) is energized, which in turn charges the closing springs. When the closing springs are charged, limit switch contacts "LS/1" and "LS/3" are opened, and limit switch contact "LS/2" is closed.

    b. Operation of the close control switch energizes the latch release coil (X) through the circuit breaker auxiliary switch "L/d" contact. The normally closed lockout relay contact "Y/2", and the limit switch contact "LS/2". The latch release coil (X) releases the closing latch. The springs then discharge to close the circuit breaker.

    c. When the spring discharges, limit switch contacts "LS/1" and "LS/3" close and limit switch contact "LS/2" opens.

    d. When the circuit breaker closes, all auxiliary switch "b" contacts open and all auxiliary switch "a" contacts close. The closing springs recharge immediately after each discharge.

    e. When the limit switch contacts "LS/3" close, the lockout relay coil (Y) is energized and opens lockout relay "Y/2" which deenergizes the latch release coil (X). Lockout relay contact "Y/1" closes which seals in the lockout relay coil (Y) as long as the "CLSE" contact is maintained. The purpose of the lockout coil (Y) is to prevent pumping of the closing mechanism when closing against a faulted circuit. If control power across the close circuit is lost and restored, the "Y" coil will be reenergized through the "LS/3" contact.

2. The circuit breaker can be tripped by operation of the trip control switch, which energizes the circuit breaker Trip Coil (TC) through the auxiliary switch "L/a" contact. When the Trip Coil is energized the opening spring is released.

B. Power Shield Solid State Overcurrent Trip Devices

[.1.4.1] [.1.15] Figure 1

1. K-line breakers with a "S" suffix incorporate the Powershield solid state overcurrent trip devices. The device provides fault and overload protection within the selective tripping scheme for Auxiliary Power distribution.

2. This device includes the power supply sensors (CT's), overcurrent sensor, Power Shield solid state logic assembly, magnetic latch and the interconnecting wiring. Each phase of the circuit breaker has a power supply sensor and overcurrent sensor. Four trip elements are available: Ground fault, instantaneous, and short-time delay, long-time delay. At CPS the Ground Fault feature is not used.

3. The logic assembly is mounted near the front of the circuit breaker and with the cubicle door open the overcurrent control panel is readily accessible. This device must be set for individual circuit conditions to provide electrical system protection. Movable plugs (pegs) are placed in the appropriate slots on the control panel to establish the long-time, short-time, instantaneous and ground fault pickup and amount of time delay. The overcurrent device, will trip at the value of the AMPERE TAP setting times the plug setting of the various pickup elements.

4. SS-13 Type Powershield is for general purpose application. It provides long-time delay tripping during a moderate overcurrent condition, which is above the long-time pickup settings, and instantaneous tripping on fault currents above the instantaneous trip setting. This is typically used for motors/pumps/fans.

5. Type SS-14 is the Selective Overcurrent Trip Device. This trip device provides long-time delay and short-time delay tripping. This is typically used for MCC or riser feeds.

C. Shunt Trips

[.1.4.1] [.1.4.2]

1. Selected Unit Substation and MCC AC Breakers are equipped with separate shunt trip coils to trip the circuit breaker when activated by CRVICs logic to automatically shed loads powered from vital power which are desirable for plant control, but not required for safe shutdown.

2. Circuit breakers, which penetrate the containment generally, have two circuit breakers in series. If a containment load has a shunt trip only one of the circuit breakers will be tripped by the shunt trip coil.

D. Significant Annunciators

[.1.11.1]

1. Automatic operation of 480VAC to Unit Substation Main Feeder Breakers are monitored by alarms. Refer to Attachment B for a summary of alarms. Integrated operation of 480VAC breakers is addressed in N-CL-OPS-262001, Auxiliary Power.

2. Loss of DC Control Power to 480V AC Substation breakers are monitored by alarms. The alarm procedures provide direction or references for restoring DC Control Power by transferring the Main Supply fuse to the 125VDC Reserve Supply.

[.1.15]

a. Breakers that lose status light indication, also lose trip power and can only be tripped manually.

b. On a loss of control power to a Class 1E Bus, transferring control power fuses may not provide DC power to the bus for control power since the reserve supply is fed from the same 125V DC MCC as the main supply.

SOER 10-2: H. B. Robinson Steam Electric Plant – In March 2010, the unit sustained damage to two 4-kV buses and the unit auxiliary transformer when an arc flash occurred in a cable conduit and the **bus supply circuit breaker failed to open on overcurrent**. Subsequently, an automatic reactor scram occurred that was complicated by an electrical fire, loss of power to balance of- plant equipment, and a temporary loss of power to an emergency bus. A safety injection initiated. The event was complicated by degraded equipment and weaknesses in operator and crew performance, including attempts to reenergize a faulted bus and challenges to the integrity of reactor coolant pump seals.

VI. Interrelationships

A. Support Systems [.1.12.1]

DC Electrical Distribution

1. Divisional and non-divisional DC Electrical Distribution provides DC Control power to the 480V K-line breakers. In some cases, DC Distribution is supplied to the controllers for Molded Case 480VAC breakers (e.g. TBCCW Pumps).

2. Breaker control power fuses are located in the Unit Substation Auxiliary cubicle.

B. Systems Supported

1. Auxiliary Power [.1.13.1]

   a. The 480V and below Circuit Breakers provide selective tripping protection for the Auxiliary Power and Low Voltage Distribution Systems. Substations use ABB/Gould K-Line circuit breakers for the main feed and load distribution. Some Unit Substation breakers can be controlled remotely; others Unit Substation breakers can only be operated manually.

   b. Most 480V loads including pumps, motor driven valves, fans heaters and low voltage distribution panels are powered through a MCC using ITE/GOULD or Siemens molded case circuit breakers.

2. Low Voltage Distribution

   The 120 VAC distribution panel use thermally actuated molded case circuit breakers similar to but smaller than the 480 VAC MCC circuit breakers.

VII. Technical Specifications

A. Safety Limits

None

B. Limiting Conditions for Operation (LCOs)

[.1.16] [.1.17]

Technical Specifications do not directly address 480VAC Breakers; however, operability of safety related switchgear associated with the breaker may be impacted. The following criteria from CPS No. 1014.11, 6900/4160/480V Switchgear/ Circuit Breaker Operability Program is used to determine SWITCHGEAR SEISMIC OPERABILITY/ ANALYSIS during breaker activities performed on OPERABLE switchgear.

1. When a breaker is placed in a configuration that removes power from the associated loads, the ITS Conditions and Required Actions for either the electrical power distribution subsystem (i.e., ITS LCO 3.8.9 or 3.8.10), or for the de-energized equipment shall be entered as appropriate for the configuration.

   a. When a breaker is placed in a 'Seismically Unanalyzed Configuration' on an OPERABLE switchgear (e.g., during operation/on-line maintenance/PMT/surveillance, etc.), the switchgear need not be declared INOPERABLE, provided the time in this configuration is limited to forty-eight (48) hours per occurrence, and appropriate personnel remain at the breaker cubicle (when the cubicle door is open) in order to return the breaker cubicle to a 'Seismically Analyzed Configuration' when directed by the Shift Management.

   b. If redundant equipment is required to be OPERABLE, then the redundant equipment should be maintained OPERABLE during this time period.

   c. These limitations have been evaluated to limit plant operation such that a seismic occurrence during this time is of such a low probability that it is not required to be postulated during this time period.

   d. If the breaker cubicle is not restored to a 'Seismically Analyzed Configuration' within 48 hours, or no appropriate personnel are at the breaker cubicle (when the cubicle door is open), then the switchgear shall be declared INOPERABLE.

2. Non-safety related (Non 1E) Div. 1 & 2 switchgear located in Seismic Cat. 1 areas do not perform any safety functions.

    a. The breakers in these cubicles may be left in the cubicles in any position providing the latching mechanism for the breaker is engaged (except when racked in), and the cubicle door is closed with the door bolts torqued or latches fully engaged as applicable.

    b. This is required to prevent any interaction concerns with other safety-related equipment or components in the vicinity during a seismic event.

3. Breakers should only be "swapped" to different bus cubicles by specific MWO/AR job step, or in emergencies.

C. Operating Requirements Manual (ORM) **[.1.16]**

1. 2.5.1 Containment Penetration Conductor Overcurrent Protective Devices

    Review the Requirements and associated actions for 480VAC breakers.

2. 2.5.2 Motor Operated Valves Thermal Overload Protection Operational Requirements

    Review the Requirements, associated actions and basis for 480VAC breakers.

VIII. Operational Characteristics

A. Precautions and Limitations [.1.14]

1. All breaker activities performed on OPERABLE switchgear shall be evaluated for switchgear operability and seismic qualification per CPS No. 1014.11, 6900/4160/480V SWITCHGEAR/CIRCUIT BREAKER OPERABILITY PROGRAM.

   a. This includes, but is not limited to, opening the cubicle door and racking operations.

   b. When verifying breakers racked in, verify that the charging spring motor circuit is energized (on breakers that are so equipped).

2. Thermal overloads may be reset once. Reclosure of a breaker that has tripped on other than thermal overload may be performed once, providing the following conditions are met:

   a. Shift Manager has given permission.

   b. Reclosure can be done remotely to prevent hazard to personnel should a breaker fault occur.

   c. Loss of component availability will cause a significant disruption of operational activities.

3. If a breaker has been determined to have tripped on a fault, or sticks in mid position between OPEN and CLOSED, or is unusually difficult to RACK IN or OUT, it should not be reset or closed without prior notification of Shift Management and Electrical Maintenance to allow for preliminary investigation.

B. Personnel Safety [.1.14]

1. SA-AA-129, Electrical Safety equipment and precautions shall be observed when working on or near energized equipment.

2. To avoid personnel injury, stay clear of moving or pre-charged parts.

Content/Skills	Activities/Notes
C. Manual Operation 480V Substation Breakers	
1. The preferred method for local operation of 480V Substation Feeder Breakers is to use the remotely mounted handswitches.	
2. Manually Trip a 480V Substation Breaker	**[.1.18.1]**
a. It is not advisable to manually trip a breaker suspected of being in an overcurrent situation; this action may result in personnel injury. Appropriate safety equipment must be worn when performing manual breaker manipulation.	**[.1.14]**
b. 480V Substation breakers can be manually tripped by depressing the red-trip push button on breaker face, then verify breaker opens by local mechanical indication.	
3. Manually Close a 480V Substation Breaker	**[.1.18.2]**
a. Prior to closing electrically operated breaker verify that the charging springs indicate CHARGED.	
b. Depress the CLOSE pushbutton on breaker face, and verify breaker closes by local mechanical indication.	
4. Manual Spring Charging 480V Substation Breaker	**[.1.18.3] Figure 8**
a. Rack breaker to the TEST position to allow access to charging tool receptacle. Refer to CPS No. 1014.11 for operability impact.	
b. Insert 480V charging tool into receptacle located on underside of breaker.	
c. Ratchet the charging tool until breaker springs are charged, as indicated by ratchet tripping free and the charging spring indication reads "CHARGED".	
d. Rack breaker back to its operating position.	
D. Racking 480V Substation Breaker	**[.1.18.4] Figure 1 & 9**
1. NOTE: Unit sub feeder breakers handle much more current than a typical unit sub breaker that feeds equipment. As such, a unit sub feeder breaker has more robust internals, and will require more force to rack in and out than a smaller breaker.	
2. Racking a 480V Substation Breaker to Disconnected Position	

a. The breaker must be verified opened prior to changing the breaker racking status. With the breaker open the Closing Spring is normally charged.

b. The Charging Motor Disconnect Switch is placed in the OFF position for Electrically Operated Breakers to prevent automatic charging of the Closing Spring.

c. Depress the Manual Trip Pushbutton on the escutcheon assembly to ensure that the Trip Spring is discharged.

d. The Racking Shutter is lifted and the Racking Crank tool is inserted. Turn the tool 'counter-clockwise' to withdrawal the breaker from the cubical. The Closing Springs automatically discharges when the breaker is racked-out to DISCONNECT.

NOTE: Gentle insertion of the racking tool is all that is required. Firm insertion of racking tool may cause gear/pall mechanism to become disengaged.

Applying excessive force with the RACKING CRANK tool when racking a breaker to the DISCONNECT position can cause distortion of the spring discharging mechanism. This could prevent the closing spring from discharging properly thus, hindering breaker operation.

e. The DISCONNECT position can be visibly verified on the racking position indicator STICKER/DECAL on the right hand side of the escutcheon assembly. Remove the racking crank tool.

f. The breaker racking linkage may need to be relaxed ~ 1/2 to 2 1/2 turns in the clockwise direction, to allow Racking Shutter to drop/close and withdraw the Padlock Plate.

g. Push in the Manual Trip Pushbutton on the escutcheon assembly, and pull out the Padlock Plate, if attachment of a Safety Tags if required.

3. Racking 480V Substation Breaker to the CONNECTED Position

[.1.18.5]

a. 480V breakers must be opened before the breaker can be racked out. Racking Shutter is interlocked closed until the breaker is opened. Failure to verify the breaker is OPEN can result in equipment damage, personnel injury, or DEATH if the interlock were to fail.

[.1.14]

b. Remove Safety Tags (if applied), and push the PADLOCK PLATE in. The Charging Spring Motor Disconnect Switch is placed in OFF for Electrically Operated Breakers to prevent the automatic charging of the Closing Spring when Control Power is applied with the makeup of the Secondary Contacts.

c. Lift the Racking Shutter, insert Racking Crank tool and turn it 'clockwise' until the racking position indicator on the cradle shows the TEST position or until the stops prevent further motion.

d. Remove the Racking Crank tool, and ensure the Racking Shutter drops. The breaker racking linkage may need to be relaxed ~ 1/2 to 2 1/2 turns in the counterclockwise direction, to allow the Racking Shutter to drop/close.

e. For Electrically controlled breakers, turn the Charging Spring Motor Disconnect Switch On to charge the Closing Spring. This can be verified using the SPRING CHARGED indicator on the escutcheon plate. A breaker with this switch left in OFF will be rendered INOPERABLE because the Charging Springs will not charge.

f. Reset/check reset automatic trip indicator (white button).

g. If excessive force is applied while racking a breaker in to the CONNECTED or out to the DISCONNECTED, position either the breaker racking mechanism, bus power stabs, or racking tracks may be damaged. This could necessitate deenergizing the entire 480V Substation to remove the breaker and repair the damage. **[.1.14]**

h. Attempting to rack in a breaker while it is still closed has resulted in damage to affected equipment and serious injuries to operators including fatalities. In these events the interlocks failed to trip the breaker when the racking activity was initiated. **[.1.15]**

E. Emergency Operation of 480V Molded Case Breaker

[.1.18.6] Figure 6

Manually operating the contacts of a 480V MCC valve breaker is done when required for Emergency Operating Procedures. Shift Management may also direct emergency operation of certain malfunctioning valves in order to prevent personnel injury, severe property damage, or to protect the public health and safety. Reference CPS No. 3515.01 section 8.4.

1. General Precautions/Important Information

[.1.14]

   a. If a circuit breaker for a MOV has previously tripped on thermal overload, additional means are to be used to prevent personnel injury or damage to the motor and or valve stem. A clamp-on ammeter should be used to determine locked rotor current or a volt-ammeter used to monitor closed limit switches on valve. EM assistance should be requested.

   b. If possible, E03 prints for the individual breaker should be consulted before operating the breaker contacts to insure the proper contactor is used. The overload heaters and motor terminations are usually mounted on the OPEN contactor.

      1) 480V breaker contactors are arranged either horizontally or vertically. On horizontal arrangements, the CLOSE contactors are on the right and the OPEN contactors are on the left.

      2) On vertical arrangements, the CLOSE contactors are on the bottom and the OPEN contactors are on the top.

   c. Manual operation of breaker contacts requires the use of a non-conducting device to depress the appropriate contactor to stroke the valve. A short hotstick, plastic flashlight, dry wooden dowel rod, plastic fuse pullers, or other suitable device may be used.

   d. ITS components that have been locally operated at the breaker contactor shall be considered INOPERABLE. An AR shall be written on any valve that has been operated locally from the breaker contactor.

2. Equipment Requirements [.1.14]

   a. An insulated device (e.g. screwdriver) should be used to depress reversing contactor.

   b. September 2002, an electrician at Dresden received an electrical flash to the face when he utilized a non-insulated screwdriver while determinating an energized breaker lead in a MCC cubical. The screwdriver shorted one phase to ground when it contacted the mechanical operating mechanism for the breaker.

      1) This could have resulted in a very serious injury. Fortunately, the individual suffered only a minor burn to his face.

      2) A similar event at CPS involving working with a screwdriver in an energized MCC cubical by a senior electrician resulted in the formation of a large plasma ball of flame. The electrician was seriously burned requiring extended hospitalization.

   c. Obtain electrical safety equipment per SA-AA-129. Lineman's Class II gloves with leather protectors, faceshield, safety glasses, hard-hat, and Nomex suit should be used.

3. Operating the Breaker

   a. Defeat the breaker door 'ON interlock' using an insulated device, and open the cubicle door.

   b. The contactor should not be held longer than required for the valve to complete its stroke, otherwise, the breaker will trip on the thermal overloads. Reliance upon the overload protection is not desirable because it places the operator's safety at risk if the overload feature would fail. [.1.14]

   c. Seal-in Valves

      1) Seal-in valves will begin to stroke as soon as the breaker contactor is depressed. Once the seal-in picks up, the contactor should be released.

      2) The valve will travel to the desired position and the contactor will drop out.

d. Throttle Valves

1) Throttleable valves will require that the contactor be depressed for the entire time that the valve is stroking to the desired position. Additional means shall be used to prevent personnel injury or damage to the motor and/or valve stem. A clamp-on ammeter shall be used to determine locked rotor current or a volt-ammeter used to monitor closed limit switches on valve. Electrical Maintenance assistance should be requested. **[.1.14]**

2) The contactor shall be released immediately upon indication that the valve has reached full stroke as indicated by position indication or locked rotor current.

Content/Skills	Activities/Notes
IX. Operating Experience (OPEX)	
A. General Beaker Failures	**[.1.15]**
1. Read the five operating experiences on Attachment A. Identify the causes for these events.	• • • •
2. What types of action should you take to prevent these problems?	•
B. Near Miss: Breaker Not Racked Out	**[.1.14]**
1. Review the event described in Attachment A.	
2. Identify the sequence of events	
3. Be prepared to discuss the fundamental human factor principles were violated.	
C. Breaker Racking Operations	**[.1.15]**
1. Review the event described in Attachment A.	
2. Identify the sequence of events	

3. Be prepared to discuss the fundamental human factor principles were violated.

X. Conclusion/Lesson Summary

Evaluate understanding of objectives by asking individuals to identify key points in the following areas.

1. What are the three types of low voltage breakers used at CPS?

2. What some of characteristics of Unit Substation Breakers?

3. Review Racking Operations and interlocks

4. What are some of the characteristics of MCC Breakers?

5. Tripping devices for each type of breaker
6. What are some of the characteristic for 208/120V Distribution Panel molded case breakers?

7. Emergency operation of molded case breakers

Attachments

Figures

OE14476 – Energized Phase on Breaker in the Full Open Position
On July 24, 2002, with Oconee 3 at 100 percent power, technicians found one phase of a MOV breaker with full voltage on the load side while the breaker in the full open position. The apparent cause is grease hardening in the molded case breaker. The operating mechanism of a breaker is lubricated for a normal life span at the factory, but like any mechanical device, it must be exercised periodically. If the ambient environment exposes molded case circuit breakers to hot or cold weather extremes, the lubrication can deteriorate or harden. This breaker was installed in the Turbine Building and has been exposed to temperatures in the neighborhood of 100 to 110 degrees Fahrenheit.

272-020524-1 Binding of Close Latches in ABB Type K-Line Low Voltage Circuit Breakers
On May 24, 2002, with Salem Units 1 and 2 at 100 percent power, a refurbished upgraded spare circuit breaker inadvertently closed during post maintenance testing. Investigators subsequently determined that binding between the primary and secondary close latches prevented the primary close latch from resetting after a previous close operation and caused the breaker to close inadvertently. ABB has made several upgrades to the original K-Line operating mechanism.

OE13457 Catastrophic MCC Breaker Failure During Trouble Shooting
On September 13, 2001, with Catawba 1 at full power, during troubleshooting of a spurious tripped nonsafety related 600v breaker on MCC, the breaker underwent catastrophic failure. The breaker produced electrical flash, fire, smoke, molten metal, metal fumes, metal fragments, and plastic fragments. No personnel injuries occurred. The breaker serves steam generator blowdown pump 1A which can be out of service for an extended period of time before steam generator water chemistry goes out of specification. Catastrophic breaker failure was due to electrical arcing from the development of an electrical tracking pathway over time. This defect was not discovered due to programmatic inadequacy, i.e. inadequate requirements for testing after the initial breaker trip. Catawba procedures/process for investigating non-safety breaker trips do not prescribe resistance or megger tests. The breaker was returned to electrical service without performance of special diagnostic tests (insulation resistance tests, over current trip test, etc.

395-010725-1 K-Line Breaker Failed to Trip on Overcurrent
On July 25, 2001, a K-1600S electrical breaker at Summer failed to trip during overcurrent testing on the workbench. Investigation by the electric shop found that the failure to trip resulted from a large wire bundle interfering with the magnetic latch trip device. The wire bundle is disconnected and rerouted only during breaker overhaul. This breaker was overhauled by a vendor in 1996, and it successfully passed post-overhaul trip testing. Subsequent successful trip tests were performed during receipt at Summer, by a vendor service shop in March 2000 after they repaired the racking mechanism, and prior to installation in the plant. These successful tests would indicate that the wire bundle was not interfering with the magnetic latch at these times.

The wire bundle is susceptible to being moved when the breaker is handled for installation and bench testing. These breakers are heavy, and there are no convenient handholds. Inadvertent movement of the wire bundle is considered to be the most likely cause of the interference that resulted in failure to trip.

OE-18132 Catastrophic Failure of MCC Bucket During Normal Operations

March 21, 2004, at Nine Mile Point a Rad Waste Operator identified a need to pump down a condenser bay pit using condenser pit pump. Because of a preexisting condition with the pump's automatic level control switches the cubicle's molded case circuit breaker was yellow caution tagged. The on-shift Rad Waste Chief requested and received permission from the Control Room to close the breaker to start the pump. The RadWaste Chief then directed the Rad Waste Operator to close the breaker to start the pump.

The Rad Waste Operator proceeded to the Motor Control Center (MCC) where he donned PPE including Class O gloves with leather over, Nomex lab coat safety glasses and hardhat. At the MCC the Rad Waste Operator opened the outer panel door and located the correct MCC cubicle. He found breaker's operating switch was not pointing directly to the off position. He moved the switch to the off position using his left hand, and noted the breaker seemed to be off. According to the operator the breaker operation appeared to be "sloppy."

The operator turned breaker to on and heard small click. Not hearing the expected thump of the contactors closing, he tapped the cubicle door using his right hand (A habit he had developed because he knew that the cubicle door had to be closed in order to position the breaker from off to on). Approximately six seconds after he tapped the breaker cubicle door the operator heard an explosion, and saw a fireball emit from the top of door. The fireball did not hit him as he was standing off to one side of the breaker cubicle. The breaker cubicle contained most of the explosion however; bottom of the door was bent out about 2".

The Radwaste Operator immediately notified the Control Room of the incident. The Fire Brigade was dispatched to investigate. No fire suppressant measures were needed. The fire was self-extinguishing.
The Rad Waste Operator was examined and confirmed to be uninjured. Operations personnel responded by quarantining the area and conducting a walk down of the bus and other potentially affected equipment. While Operations personnel were preparing to de-energize the MCC the feeder breaker tripped, de-energizing the "A" and "C" sections of the MCC bus.

The failed MCC bucket was examined to determine the cause for its failure. Based on the examination, the most probable cause for the failure was insulation failure of the "A" phase line side lead, resulting in a phase to ground fault to the breaker's mounting bracket.

As of 9/22/04 at CPS, the Diesel Generator sumps pump breakers are cycled on/off to control the pumps per 3217.02 and the Site Safety Committee is investigating the correct fix for this.

Two things to note:

1. Breaker felt "sloppy" during manipulations.
2. Individual was standing off to the side during breaker manipulation.

On May 16, 2000, while at 100 percent power, Oyster Creek identified that the 'A' CRD pump tripped during a start attempt to support post maintenance testing. The breaker was checked and the cause of the trip was determined to be the thermal overload.

The operations supervisor directed electricians to perform a bridge and megger of the pump motor prior to making a second attempt to start the pump. The bridge and megger was performed and positive results were reported. The electricians were then directed to rack in the breaker at which time they informed the operations supervisor that the breaker was not racked out.

The electricians did not rack the breaker out because they assumed that the breaker could not close with the trip alarm present. They believed that the local bell alarm would have to be reset before the breaker could close. It was subsequently determined that the breaker could have closed on either a manual or automatic start signal, even with the local alarm in.

The root cause was determined to be miscommunication between the operations supervisor and the shift electricians. A pre-job briefing was not conducted and the control room was not notified prior to the start of work. Corrective actions to this event include; reviewing the incident with all plant electricians, on back shifts, a briefing will be held with the operations supervisor to establish the method to control equipment for the activity planned. Also, the operations and maintenance departments established aligned expectations for the assignment and performance of maintenance activities when providing direction to maintenance crews during back-shifts and weekends.

On March 3, 2000, with Hatch Unit 2 shut down for a planned outage, clearance activities were being conducted. A Reactor Feed Pump Turbine (RFPT) 'A' suction valve supply breaker was being racked out by a system operator (SO) to support maintenance.

The SO placed the disconnect operating handle to the "off" position. He then placed the handle to the "door open" position so he could open the door, unlatch the pan assembly, and rack-out the breaker. The metal cam on the disconnect operating handle failed to clear the operating shaft shoulder. Therefore, the left side of the pan assembly was pulled partially from its frame when he opened the frame door because it was still connected through the operating shaft to the operating handle. The right side of the pan assembly remained in place because, it was latched by the still-engaged pan assembly latching mechanism located on the right side of the frame. Opening the frame door with the cam still engaging the shaft shoulder twisted the pan assembly within its frame (the left side of the pan assembly was pulled from the frame while the right side of the assembly remained in place). The twisted pan assembly twisted the stabs causing one or two of them to bend. This type of misalignment was a common occurrence.

When the SO attempted to push the pan assembly fully into its frame, two of the stabs touched, causing a phase-to-phase short, a loud pop was heard and a flash and smoke from the breaker were observed. A phase-to-phase short caused the 600 VAC MCC's supply breaker to trip open on fault current. The stabs and insulating block were damaged, and the frame was discolored.

The cause of this event was the metal cam in the disconnect operating handle failing to clear the operating shaft shoulder. The design allows the pan assembly to be twisted or rotated about on an axis located on the right side of the frame when the door is opened while the metal cam remains engaged to the operating shaft. The stab contact fingers are spaced such that bent contact fingers of one phase can touch bent fingers of another phase. Wear, misalignment, and lack of lubrication may be contributing factors.

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5011-3D	AUTO TRIP 480V BUS FEEDER BKR	BREAKER ALARM RELAY 452 r		Indication of the trip of any 480V Manual Feeder Breaker on any unit substation supplied from the 6900V 1A(1B) Busses
5011-3E	DC FAILURE 480V BUS	ALARM RELAY 74		Breakers that lose status light indication, also lose trip power and can only be tripped manually.
5011-3F	AC UNDERVOLTAGE 480V BUS	UV RELAY 427X1		STATUS ALARM ONLY
5011-4D	AUTO CLOSE 480V BUS TIE BKR	Bkr Closed & HS in Auto After Open	Bkr Closed & HS in Auto After Open	STATUS ALARM ONLY Non-Fault Trip of the associated 480V Bus Main Breaker
5011-4E	AUTO CLS BLOCKED 480V BUS TIE BKR	TRIP AND LOCKOUT RELAY		STATUS ALARM ONLY Overcurrent trip of the associated 480V Transformer Breaker
5012-3B	AUTO TRIP 480V BUS FEEDER BKR	Alarm Switch 452-400		STATUS ALARM ONLY
5012-3C	DC FAILURE 480V BUS	DC Failure Alarm Relay 74-4		STATUS ALARM ONLY Breakers which lose status light indication also lose trip power and can only be tripped manually

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5012-3D	AC UNDER VOLTAGE 480V BUS	AC Undervoltage Relay 427X1-4		STATUS ALARM ONLY
5060-5C	AUTO TRIP 480V BUS FEEDER BKR	Auto Trip Any Feeder Breaker on 480V BUS A or 1A		STATUS ALARM ONLY
5060-5D	NOT AVAILABLE 480V BUS MAIN FEED BKR	Bus A or 1A Main Feed Breakers	Racked-Out	STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.
		Bus A or 1A Control Power Monitor	Deenergized	
5060-6B	DC FAILURE 480V BUS	DC Control Power Failure 480V Bus A or 1A		STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.
5061-5C	AUTO TRIP 480V BUS FEEDER BKR	Auto Trip Any Feeder Breaker on 480V BUS B or 1B		STATUS ALARM ONLY
5061-5D	NOT AVAILABLE 480V BUS MAIN FEED BKR	Bus B or 1B Main Feed Breakers	Racked-Out	STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.
		Bus B or 1B Control Power Monitor	Deenergized	
5061-6B	DC FAILURE 480V BUS	DC Control Power Failure 480V Bus B or 1B		STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.

Racked-In/Connected:

- Breaker fully inserted into cubicle.
- Primary (line) and secondary (control power) contacts made-up.
- Rollers on racking cam assembly are engaged in the cradle, with the positioning pins on breaker racking cam assembly lever engaged in the guide rails.

Racked-Out/Disconnected:

- Breaker inserted into cubicle.
- Primary and secondary contacts not made-up.
- Rollers on racking cam assembly are engaged in the cradle, with the positioning pins on breaker racking cam assembly lever engaged in the guide rails.

Test:

- Breaker inserted into cubicle.
- Primary contacts not made-up.
- Secondary contacts made-up.
- Rollers on racking cam assembly are engaged in the cradle, with the positioning pins on breaker racking cam assembly lever engaged in the guide rails.

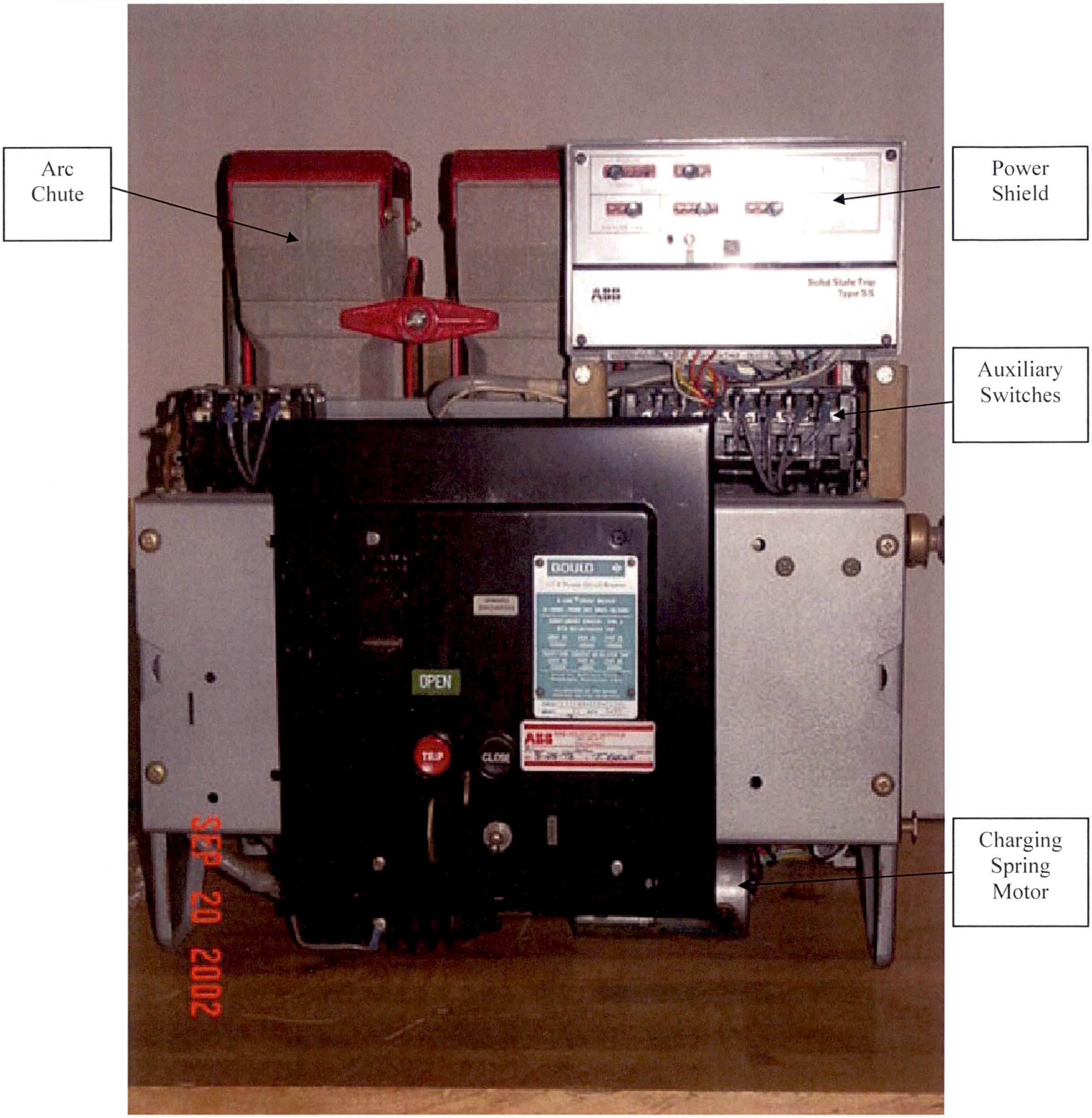
Drawn-Out:

- Breaker removed from cubicle.
- Breaker on rails.
- Primary and secondary contacts not made-up.

Removed:

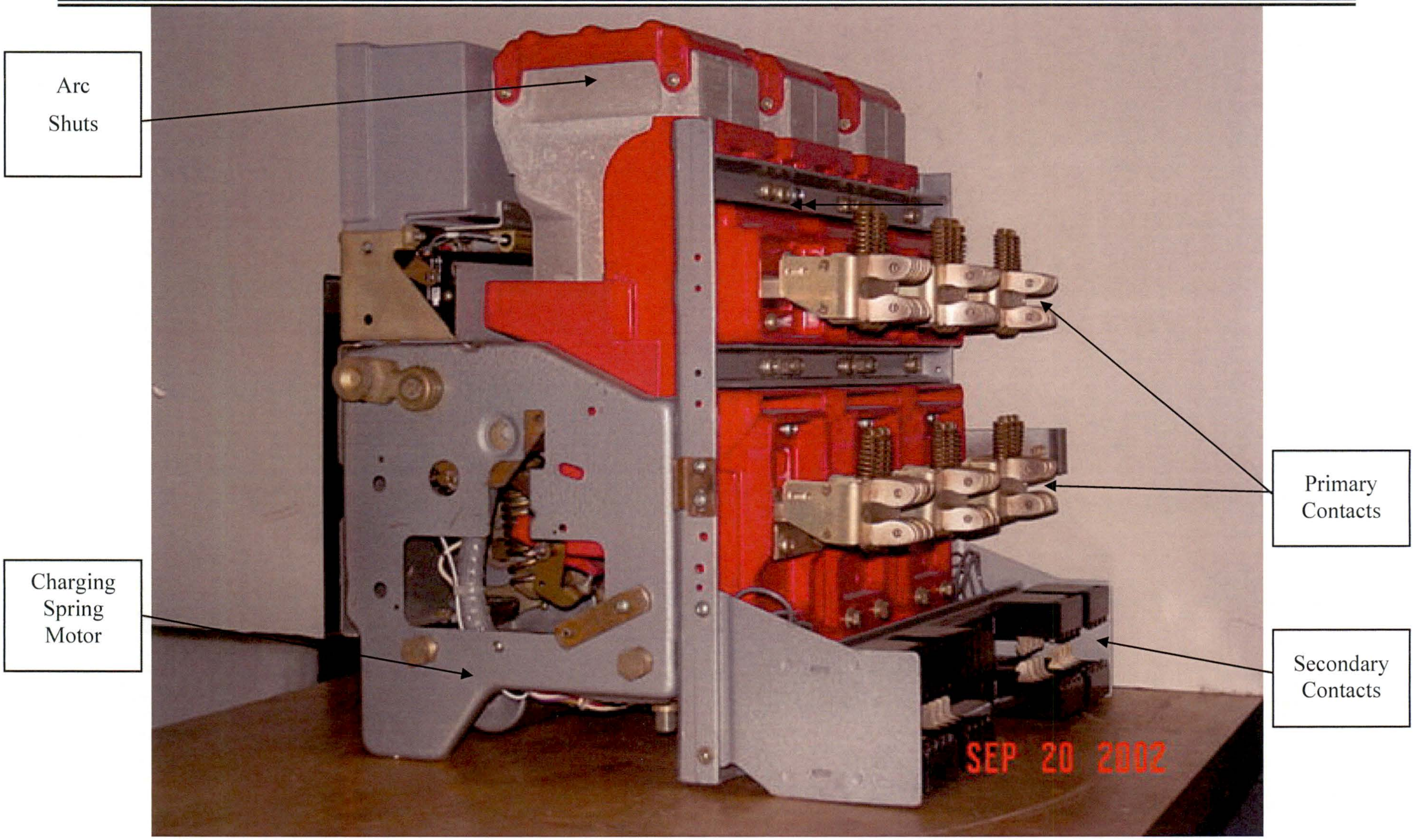
- Breaker removed from cubicle.
- Rail inserted in cubicle.

Figure 1



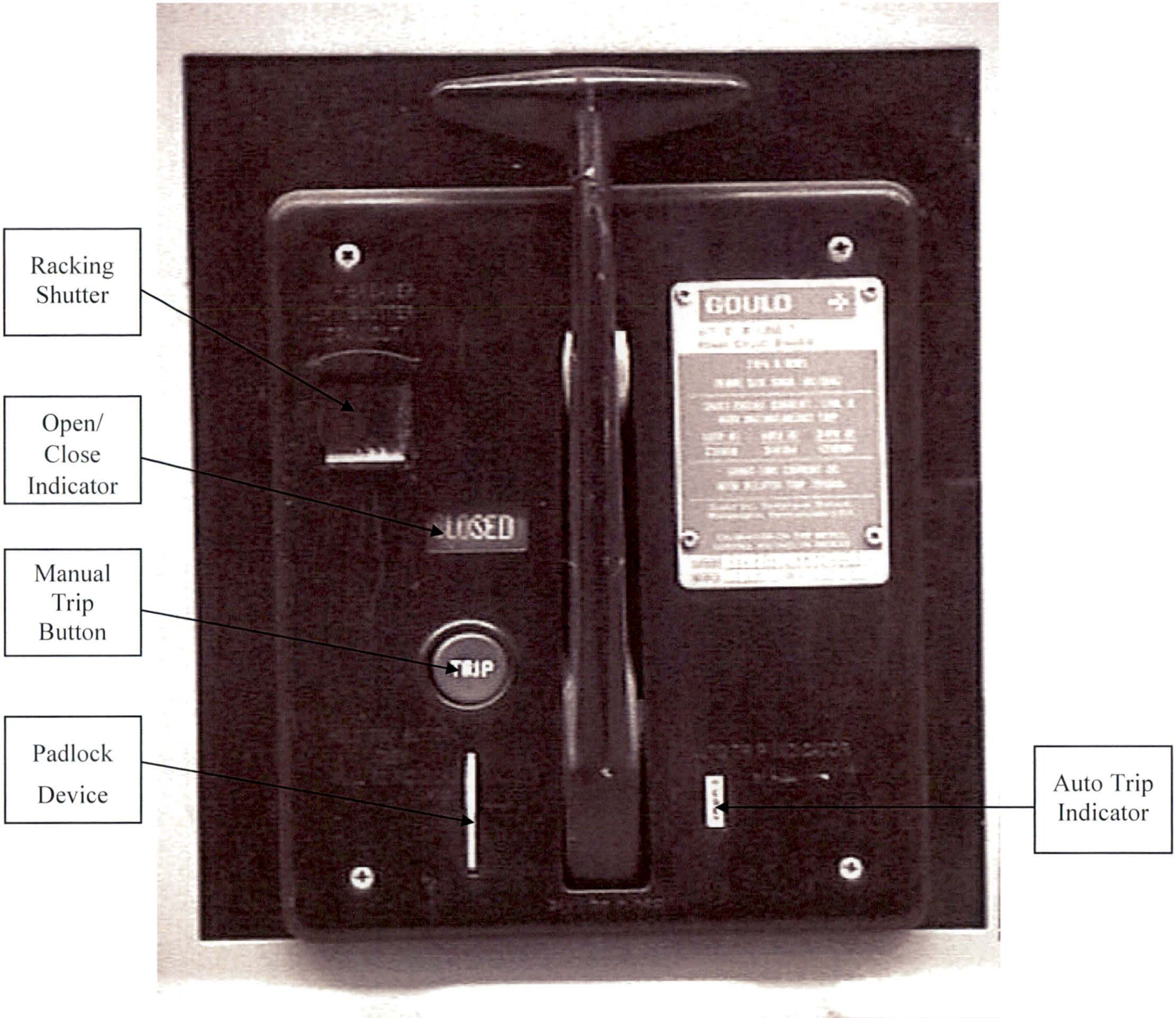
480V SUBSTATION K-LINE CIRCUIT BREAKER
(K-1600S FRONT VIEW)

Figure 2

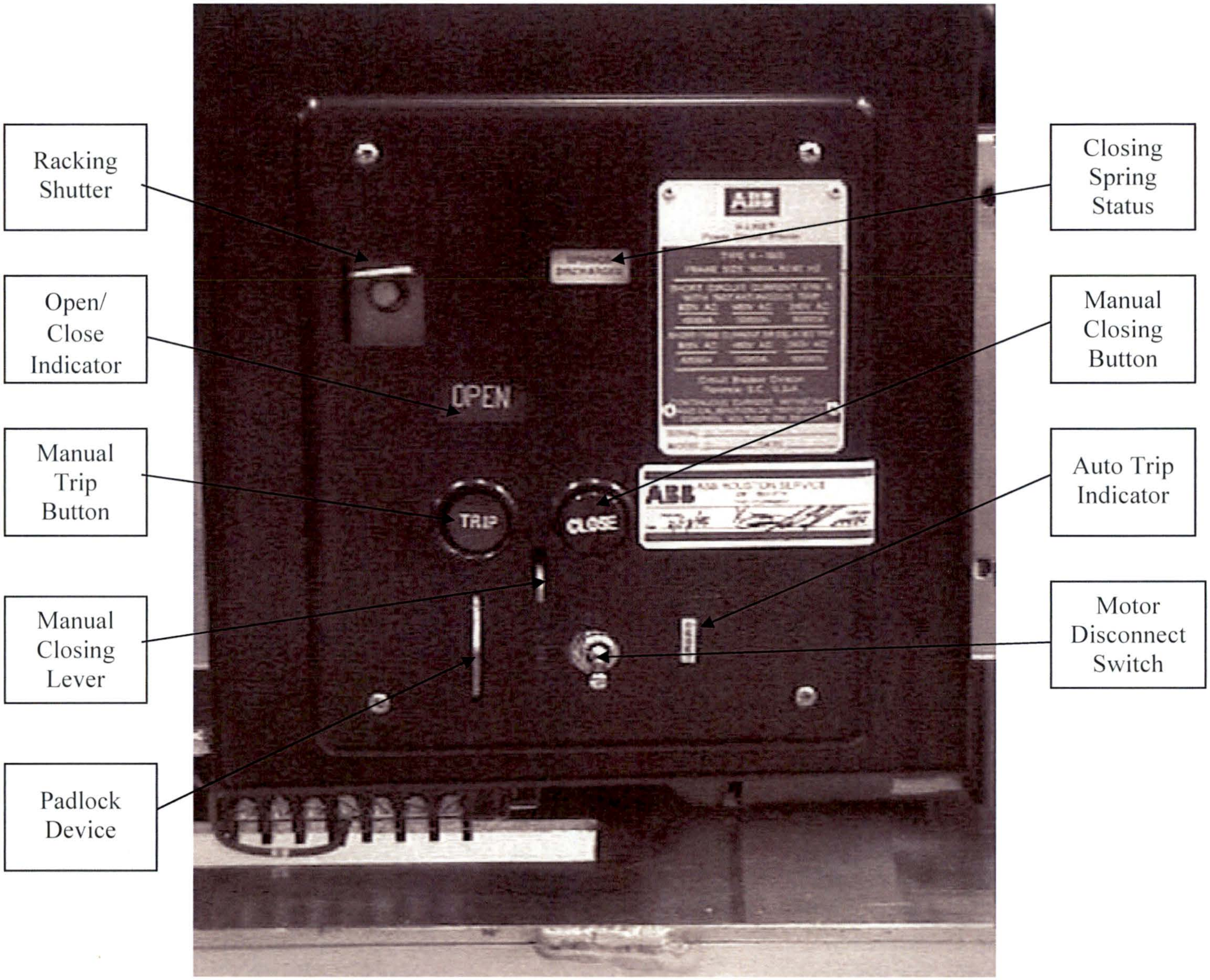


480V SUBSTATION K-LINE CIRCUIT BREAKER
(K-1600S SIDE VIEW)

Figure 3

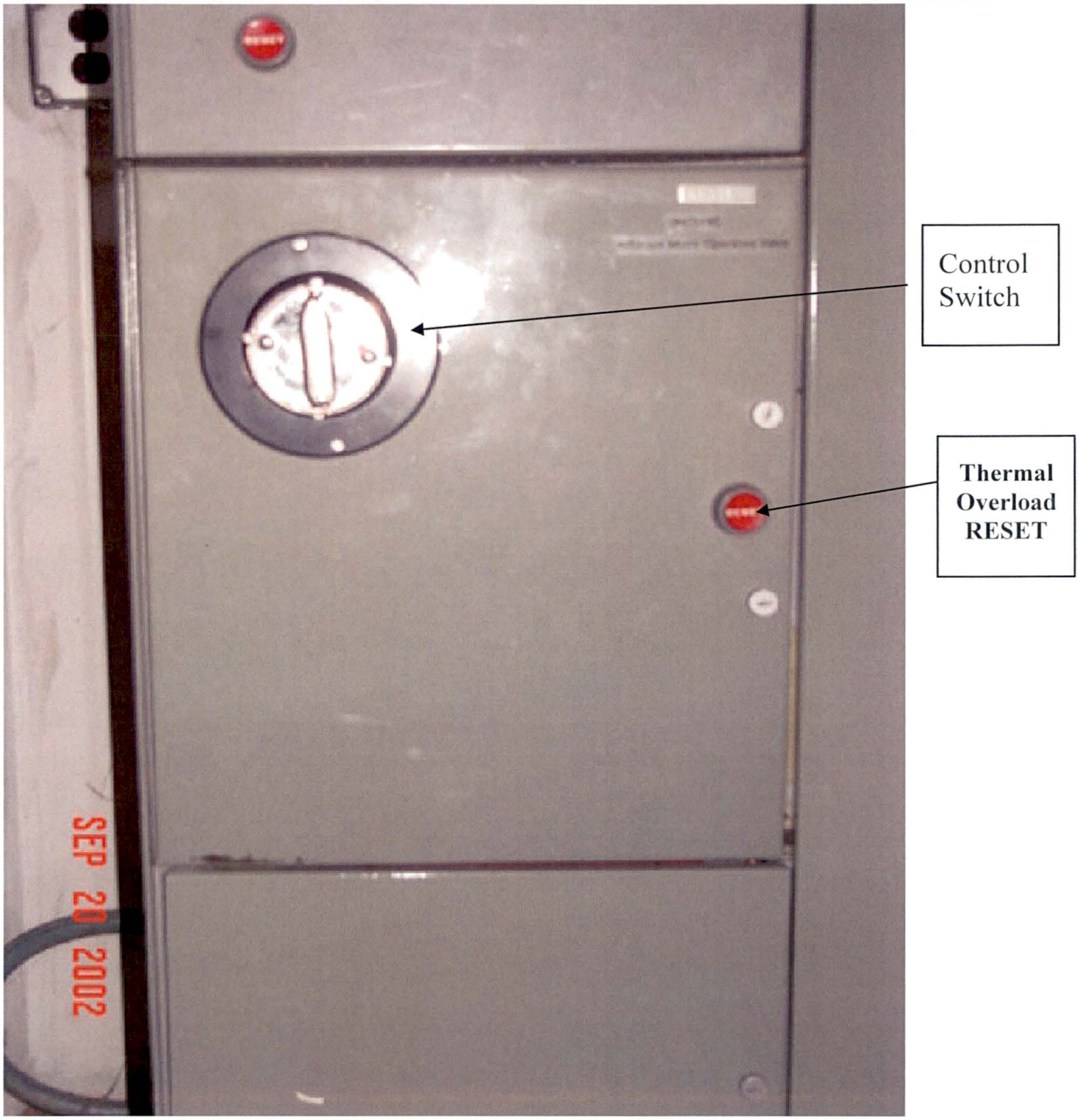


480V SUBSTATION K-LINE CIRCUIT BREAKER MANUAL - ESCUTCHEON FACE PLATE (K-600S FRONT VIEW)



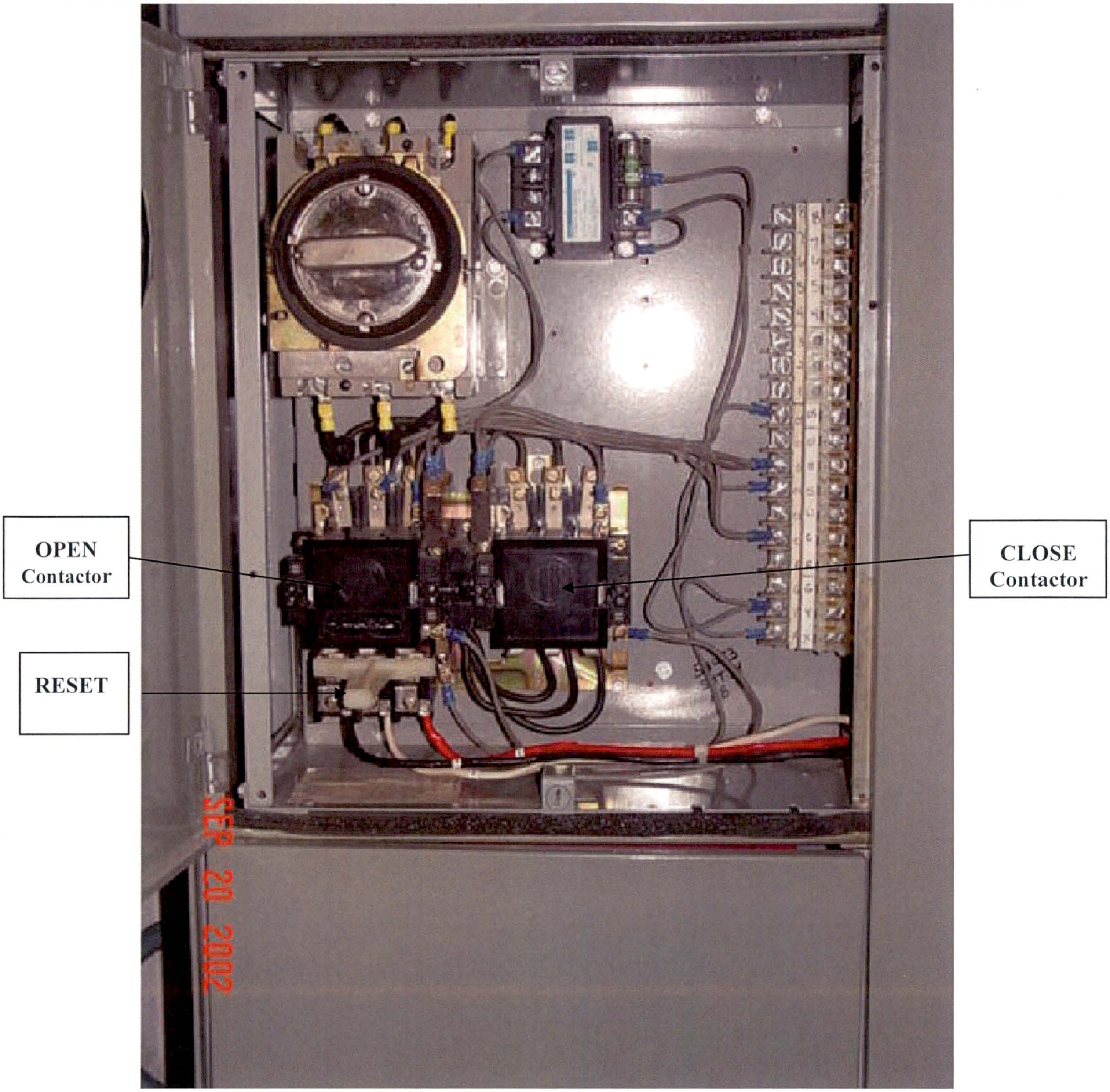
480V SUBSTATION K-LINE CIRCUIT BREAKER ELECTRICAL - ESCUTCHEON FACE PLATE (K-1600S FRONT VIEW)

Figure 5



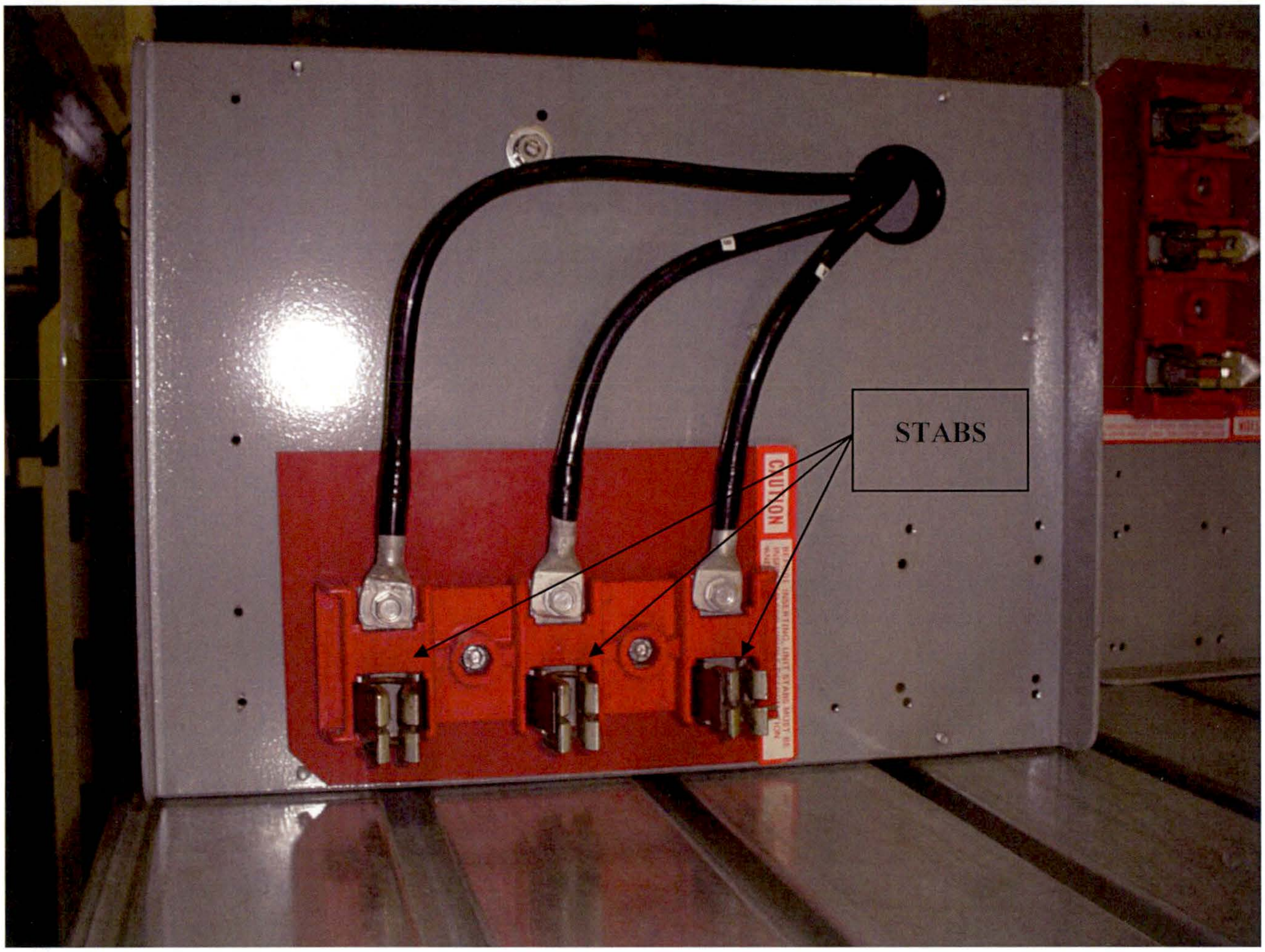
480V MCC MOLDED CASE CIRCUIT BREAKER BUCKET COMPARTMENT

Figure 6



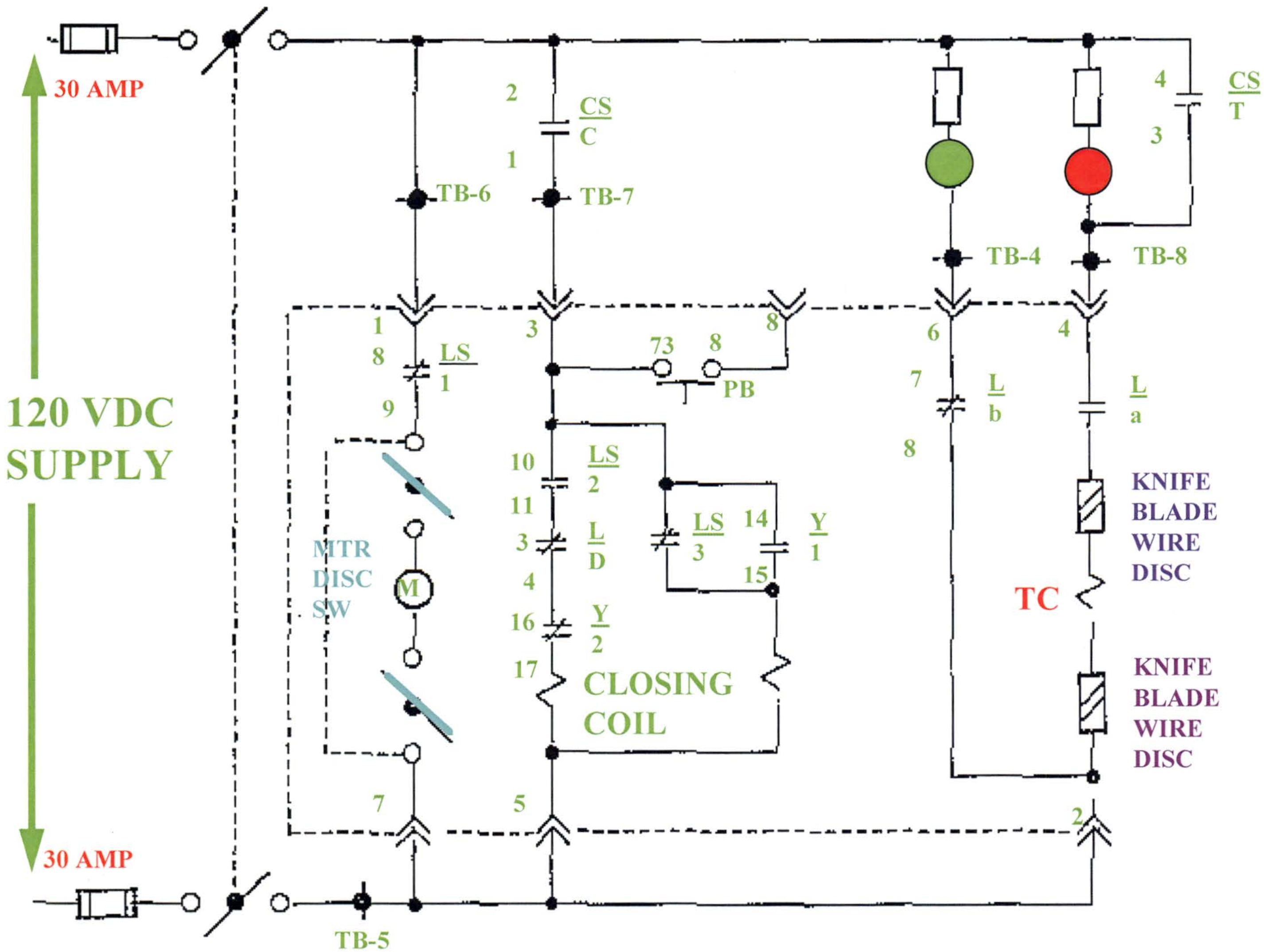
480V MCC MOLDED CASE CIRCUIT BREAKER BUCKET
(FRONT VIEW)

Figure 6a

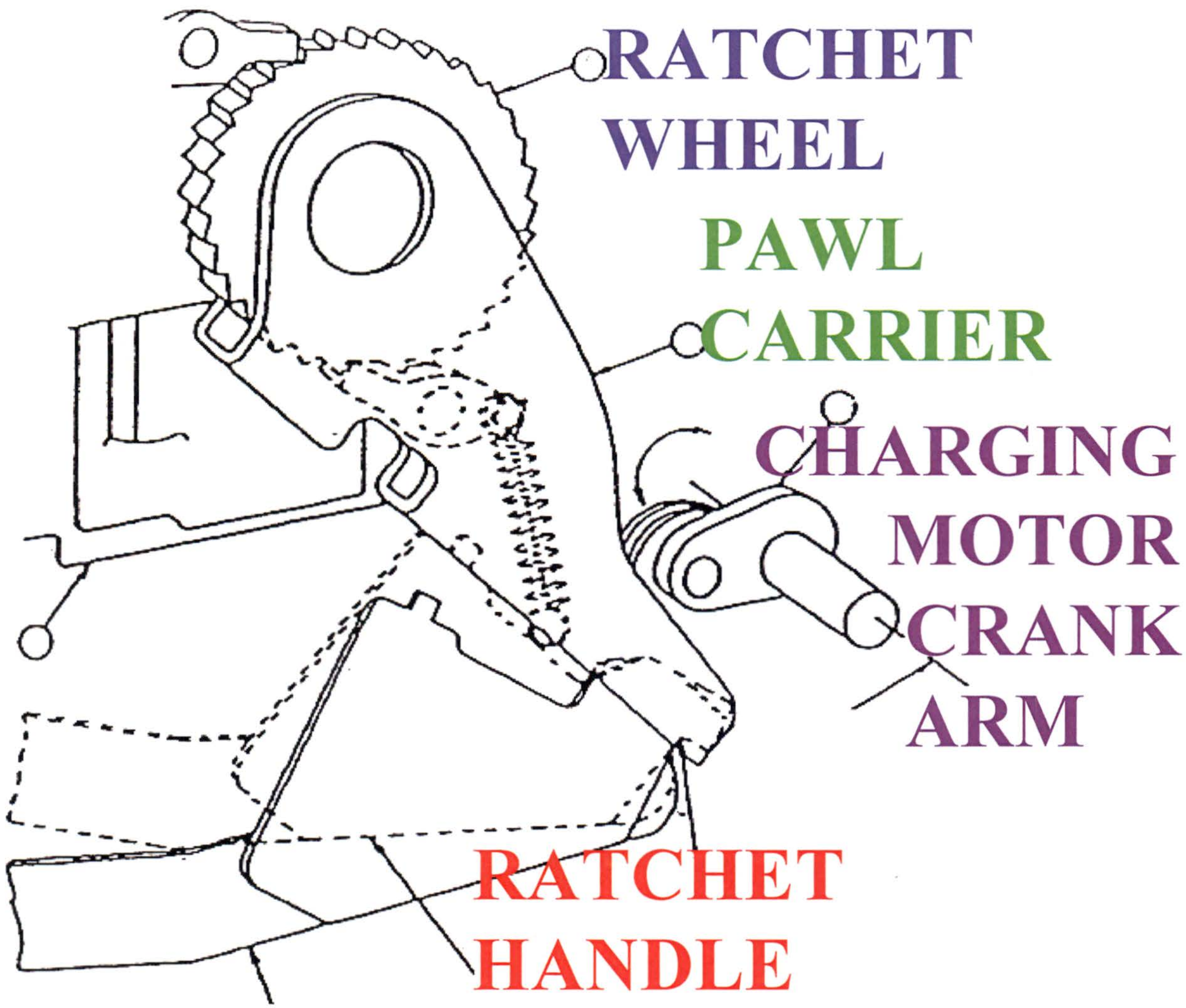


480V MCC MOLDED CASE CIRCUIT BREAKER BUCKET (REAR VIEW)

Figure 7

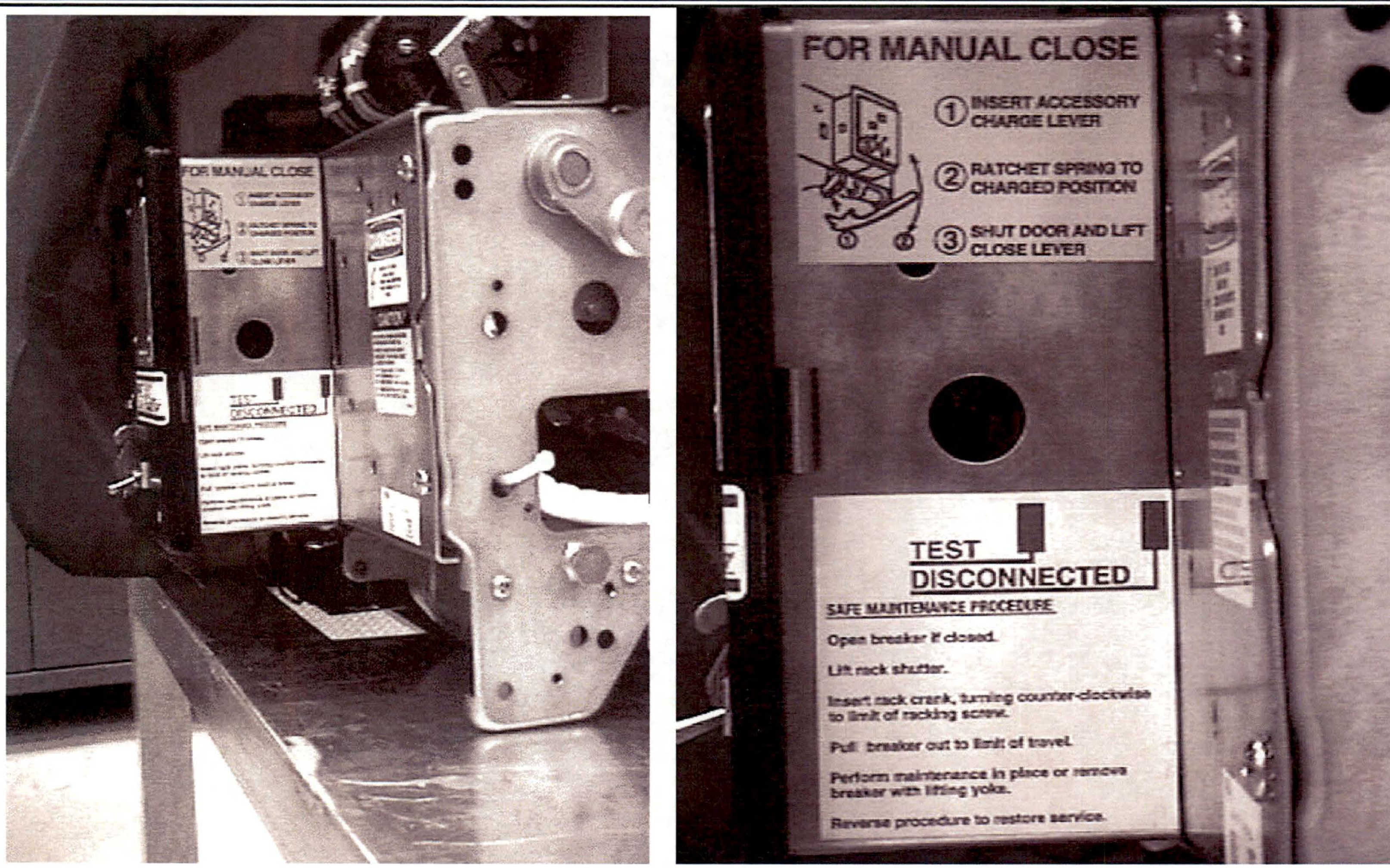


480V SUBSTATION K-LINE CIRCUIT BREAKER CONTROL CIRCUIT SCHEMATIC



480V SUBSTATION K-LINE CIRCUIT BREAKER
CHARGING SPRING MECHANISM

Figure 9



480V SUBSTATION K-LINECIRCUIT BREAKER
RACKING POSITION INDICATION

Exelon Generation.

Course/Program:	ILT/NLO/LORT	Module/LP ID:	LP85115
Title:	© CIRCUIT BREAKERS (6.9 AND 4.16 KV)	Course Code:	N/A
Author:	Jim Bunning	Revision/Date:	005 / 06/29/2018
Prerequisites:		Revision By:	M. Beeler
Responsible Site	Clinton	Est. Teach Time:	5.0 hours

Qualified Nuclear Engineer Review (If applicable):	N/A	Date:	N/A
Training Supervision Review: (Print name / Signature)	R. J. Frederes /S/	Date:	07/02/18
Program Owner Approval: (Print name / Signature)	Richard Champley /S/	Date:	07/11/18

TABLE OF CONTENTS Pg. #

OBJECTIVES

Form memory, unless otherwise stated, and with 100% accuracy, in accordance with the course reference materials and procedures, the trainee shall be able to:

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.1	Recall the design and purpose of High Voltage Circuit Breakers.	x	x	x	x	4
.1.2	Recall the following modes of operation while operating the system:					
	.1 Racked In	x	x	x	x	16
	.2 Racked Out	x	x	x	x	16
	.3 Racked to Test	x	x	x	x	16
.1.3	Trace the control power flowpaths on the appropriate Electrical Schematic for the following modes of operation:					
	.1 Automatic Start	x	x	x	x	17
	.2 Automatic Trip	x	x	x	x	17
.1.4	Recall the function, theory of operation, interlocks, and characteristics of High Voltage Circuit Breakers.	x	x	x	x	8, 10, 12, 13, 28
.1.5	Recall the physical location to access and operate the High Voltage Circuit Breakers.	x	x	x	x	5
.1.6	Locate or describe the location of indicating lights for breaker indication in the plant.	x	x	x	x	33
.1.7	Recall the systems that support the High Voltage Circuit Breakers and the nature of the support provided.					
	DC Electrical Distribution	x	x	x	x	35
.1.8	Determine if LCOs have been met or exceeded, and identify the required actions in accordance with above references, when given a copy of Technical Specifications, CPS 1014.11, and various plant conditions.	x	x		x	36

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.9	State the function of the following Westinghouse and Cutler-Hammer 4.16/6.9 KV Switchgear components:					
.1	Floor Trippers	x	x	x	x	9
.2	Mechanism-Operated Cell (MOC) Switch	x	x	x	x	9
.3	Truck-Operated Cell (TOC) Switch	x	x	x	x	9
.4	Secondary Disconnecting Contacts	x	x	x	x	10, 14
.5	Manual Charging Lever (maintenance handle)	x	x	x	x	12
.6	Levering-in Device	x	x	x	x	12
.7	Rail Latch	x	x	x	x	13
.8	Secondary Contact Operating Rod	x	x	x	x	14
.1.10	Identify the following, when given a diagram of a Westinghouse or Cutler-Hammer Breaker mechanism, or at a training breaker:					
.1	Manual Open Plunger	x	x	x	x	12
.2	Manual Close Plunger	x	x	x	x	12
.3	Breaker Position Indication	x	x	x	x	14
.4	MOC Switch Operating Pin	x	x	x	x	14
.1.11	Identify the following, when given a diagram of a Westinghouse or Cutler-Hammer breaker cubicle with the breaker removed, or at a training breaker:					
.1	Floor Trippers	x	x	x	x	8
.2	TOC Switch	x	x	x	x	9
.3	MOC Switch	x	x	x	x	14
.1.12	Describe the following for a Westinghouse Breaker or Cutler-Hammer breaker in Test:					
.1	Operation of the MOC Switch	x	x	x	x	15
.2	Function of the Local Control Switch	x	x	x	x	16
.1.13	Describe the differences between the Westinghouse Breakers and Cutler-Hammer used at CPS and state where each type is used.	x	x	x	x	16

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.14	Describe the operation of the Westinghouse Breaker or Cutler-Hammer Floor Tripping and Closing Spring Release Interlocks.	x	x	x	x	16
.1.15	Describe the purpose of the following Westinghouse Breaker interlocks:					
.1	Floor Tripping and Closing Spring Release	x	x	x	x	9
.2	Anti-Close	x	x	x	x	9
.3	Breaker Cell Coding Plates	x	x	x	x	10
.4	Levering-in	x	x	x	x	13
.1.16	Describe the following operations when given a diagram of a Westinghouse Cutler-Hammer Breaker mechanism panel, or at a training breaker:					
.1	How to manually charge a Westinghouse or Cutler-Hammer Breaker	x	x	x	x	12
.2	How to manually close/trip a Westinghouse or Cutler-Hammer Breaker	x	x	x	x	19, 20
.1.17	Describe how the MOC Switch determines actual breaker position, given a diagram of a Westinghouse or Cutler-Hammer breaker cubicle and mechanism panel, or at a training breaker.	x	x	x	x	9
.1.18	Predict the impact/consequences of the following events:					
.1	Not pushing the Levering-in Device back into the Breaker compartment prior to shutting the door on a Westinghouse or Cutler-Hammer Breaker	x	x	x	x	30
.2	Failure to turn the Motor Disconnect Toggle Switch to on after racking in a GE Breaker	x	x	x	x	30
.3	Improperly racking in a breaker (both GE and Westinghouse or Cutler-Hammer Breakers)	x	x	x	x	30

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.4	Not fully inserting the Auxiliary/Secondary Contacts on a General Electric Breaker	x	x	x	x	30
.1.19	State the function of the following General Electric (GE) Breaker components:					
.1	Elevating Mechanism	x	x	x	x	21
.2	Elevating Motor and Clutch (SARRACS Unit)	x	x	x	x	22
.3	Positive Interlock	x	x	x	x	23, 27
.4	Spring Discharge Cam	x	x	x	x	23
.5	Auxiliary Contacts	x	x	x	x	25
.6	Spring Release Interlock	x	x	x	x	27
.1.20	Identify the following, given a diagram of a GE Breaker/Cubicle, or at a training breaker:					
.1	Positive Interlock	x	x	x	x	23
.2	Spring Discharge Cam	x	x	x	x	23
.3	Auxiliary Switch	x	x	x	x	25
.4	Auxiliary Contacts	x	x	x	x	25
.5	Open/Closed Indicator	x	x	x	x	25
.6	Charge/Discharged Indicator	x	x	x	x	25
.1.21	Describe, given a diagram of a GE Breaker/ Cubicle, or at a training breaker:					
.1	How to manually charge the breaker	x	x	x	x	26
.2	How to manually rack in or out the breaker	x	x	x	x	29

Exelon Generation

Evaluation Method & Passing Criteria: WRITTEN EXAMINATION WITH SCORE ≥ 80%.

References

- K2801-0164, Metal Clad Switchgear for Magne-Blast Air Circuit Breakers
- K2968-0002, 4160V Buses 1A and 1B Metal Clad Switchgear
- K2968-0011, Instructions for Porcel-line Type DHP-VR Circuit Breakers
- K2968-0004, Instructions for Porcel-line Type DHP Magnetic Air Circuit Breakers
- CPS 3501.01, HIGH VOLTAGE AUXILIARY POWER SYSTEM
- OP-AA-108-106, EQUIPMENT RETURN TO SERVICE
- MA-AA-716-012, POST MAINTENANCE TESTING
- SA-AA-129, Electrical Safety
- CPS 1014.11, 6900/4160/480V SWITCHGEAR/CIRCUIT BREAKER OPERABILITY PROGRAM
- CPS 3515.01, OPERATION OF 6900/4160/480V CIRCUIT BREAKERS
- CPS DB351501.01 4160V Div 3 Breaker Racking
- Condition Report #1-98-10-031
- Condition Report #1-97-08-223
- INPO Significant Operations Experience Report (SOER) 98-2
- E02-1SA99 sheet 001
- E02-1SA99 sheet 004
- SOER 10-2, Engaged, Thinking Organizations
- INPO 15-004, Operator Fundamentals
- IER 17-005, Line of Sight to the Reactor Core

Commitments: None

LESSON PLAN HISTORY PAGE

REV.	DATE	DESCRIPTION
0	6/24/94	Original
1	05/30/02	Update to new Exelon format per TQ-AA-210-3201 R00 Lesson Plan Template (Portrait). Incorporated comments from System Engineer. Revised and updated objectives. Resolved missing KA links to lesson plan.
2	11/16/06	Incorporated TRACER#2005-05-0031A. This required clarifications and clerical changes. Incorporated TRACERS #2006-05-0025A and 0115A to update use of SARRACS remote racking tool on Div 3 medium voltage breakers, correct lesson plan formatting, and added pictures to PPT presentation.
3	11/27/12	01185341-70, Correct the objective page numbering. Added SER 3-05 and SOER 10-2 to References and Lesson plan. Brought out the trip coil integrity is monitored by the Red light indication. Corrected the CW pump has a backup DC trip power source. WC-AA-105, no longer exists replaced with OP-AA-108-106, EQUIPMENT RETURN TO SERVICE and MA-AA-716-012, POST MAINTENANCE TESTING
4	1/29/18	Revised objectives for clarity. Added references to IER 11-3 and IER 17-005.
5	6/29/18	Removed erroneous information with respect to GE breaker control power fuses. Added OPEX on LER 2016-012-00.

Instructional Methods:

- Lecture/discussion
- Case studies
- Activities
- Breaker racking at the Maintenance Learning Center
  - Mandatory for initial NLO or others that will be doing breaker racking in the plant.
  - Optional, but preferred for all others during initial training
  - Optional, but preferred for continuing training

Media:

- PowerPoint
- White board
- Handouts
- Trainee text
- Prints

I. Introduction

A. Topic Introduction

Clinton Power Station is designed with many automatic features associated with safety systems. Many of these safety functions are carried out by either opening or closing high voltage circuit breakers. As the following event shows, improper operator action associated with these breakers can result in equipment inoperability or unavailability.

Event Title: 2A Safety Injection Pump Rendered Technically Inoperable Because of Misaligned Circuit Breaker

Event Summary: On September 27, 2001, the breaker for the 2A safety injection (SI) pump at Byron Unit 2 was found with the mechanically-operated contact (MOC) operating pin misaligned with the MOC operating channel in the breaker cubicle. The problem was discovered when one of the 2A SI pump cubicle cooler fans failed to start after the pump breaker closed. The MOC operating pin connection occurs when the breaker is racked into the cubicle. The misalignment resulted in damage to the breaker. The cubicle cooler fans not receiving a start signal when breaker closed rendered the 2A SI pump inoperable. When non-licensed operators racked in the breaker for the 2A SI pump, it was not correctly aligned with the MOC operating channel.

This lesson will address breaker design, how to rack breakers in and out, how to place breakers in test, and what to look for to ensure that non-safety and safety related components will respond when called for during normal and transient conditions.

B. Overview of training session

This subject will be presented in a 5-hour classroom session, which includes:

1. Lecture
2. Exercises involving the tracing of the major flow paths on a figure that will be provided.
3. Objectives
4. Racking and inspection of a high voltage breaker in the plant or in a training facility.
5. Exam

C. Objectives

1. The objectives provide the foundation for learning this topic and include the following:

    a. Recalling the system purpose and major system flowpaths, and major component functions.

    b. Recalling the function, theory of operation, controls, automatic functions and/or interlocks associated with major system components.

    c. Recalling functional interrelationships between this system and other plant systems.

    d. Recalling the impact/consequences of system problems.

2. Review the objectives to familiarize yourself with the knowledge necessary to attain mastery of this topic.

D. Evaluation

1. A check for understanding of objectives will be evaluated by one or more of the following:

    a. The instructor periodically asking questions throughout the presentation in the form of an interim summary.

    b. A written examination with a minimum score of 80%.

    c. For those who will actually be performing breaker racking evolutions in the plant, further on the job training and evaluation will be required.

E. Management Expectations

1. Safe nuclear power plant operation is based upon the principle that each individual accepts the unique and grave responsibility inherent in using nuclear technology.

2. Evolutions involving high voltage circuit breakers present electrical safety concerns. It is expected that all persons will follow the applicable safety precautions and use the appropriate safety equipment at all times.

II. System Purpose

A. System Purpose

[.1.1]

This class of circuit breaker serves three functions:

1. Control power distribution or equipment operation.
2. Act as a protective device to interrupt fault current in order to prevent equipment damage or personnel injury.
3. Provide for equipment or circuit isolation.

B. Design Basis

High voltage circuit breakers support the ability of the associated systems to perform many design functions, safety and non-safety related.

OPTIONAL ACTIVITY

Have the students individually create a list of systems that are served by high voltage circuit breakers (example: CCW, CW, CD) on a piece of paper.

Then break the class into small groups and have them compare lists, then create one list with all of the breakers/systems that they came up with.

Then list on the board all of the systems that the students thought of.

Lastly, ensure that someone thought to include the feeder breakers to the busses. Point out that improper racking of these breakers has the potential to create severe plant transients and affect the ability of the plant to respond to transients.

III. SYSTEM DESCRIPTION

A. System Overview

Westinghouse type DHP De-ion Draw-out circuit breakers are used on:

- 6900V Bus 1A (762' Aux Building East)
- 6900V Bus 1B (762' Aux Building West)
- 4160V Bus 1A (762' Aux Building East)
- 4160V Bus 1B (762' Aux Building West)
- 4160V Buses 1A1 (781'Aux Building East)
- 4160V Buses 1B1 (781'Aux Building West)
- 6900V Bus RR1A, 1RR01E (781' East Fuel Building, the "2A" and "5A" breakers)
- 6900V Bus RR1B, 1RR02E (781' West Fuel Building, the "2B" and "5B" breakers)

(All breakers on the above busses are the Westinghouse DHP type EXCEPT the breakers listed below, which serve the Reactor Recirculation Pumps).

Cutler-Hammer type DHP-VR circuit breakers are used on:

- 6900V Bus 1A: Recirc Pump 1A feeder breaker (the "3A" breaker)
- 6900V Bus 1B: Recirc Pump 1B feeder breaker (the "3B" breaker)
- 6900V Bus RR1A: 1RR01E Recirc Pump Local feeder breaker (the "4A" breaker)
- 6900V Bus RR1B: 1RR02E Recirc Pump Local feeder breaker (the "4B" breaker)

General Electric Magne Blast Vertical Lift type air circuit breakers are used on: 4160V Bus 1C1

[

IV. Components

A. Westinghouse Metal-Clad Switchgear

The Porcel-line metal-clad switchgear is an assembly of circuit breaker housings and auxiliary housings.

The circuit breaker housing has provisions for a removable circuit breaker. It is composed of bolted together cubicles; the breaker bus cubicle, the line cubicle, the control cubicle, and sometimes the upper rear cubicle. It also includes high voltage equipment, primary connections, low voltage equipment and control devices. A hinged instrument panel, located on the front of the circuit breaker housing, provides access to the breaker, fuses and auxiliary control devices. Internal compartments provide metal isolation between the secondary control devices, the circuit breaker, the main bus and the primary line terminators. Access to the primary equipment is provided by bolted on covers, which should not be removed unless exposed circuits are de-energized.

Figure 1

The auxiliary housing contains miscellaneous equipment, which cannot be contained in the circuit breaker housing. It is similar in construction and assembly to those cubicles in the breaker housing. A hinged instrument panel is also located on the front of the auxiliary housing.

The rear sheets have grill work at the top and bottom to allow ventilating air to pass through the line cubicle. A chimney and grill work over the breaker allows for expansion of gases due to breaker interruption and ventilation of the breaker compartment.

Figure 2

Rotating, disconnecting potential transformers and fuses are trunnion mounted. The rotating assembly is mechanically connected to the front door of the compartment. Opening the door rotates the assembly, breaking the primary and secondary contacts and grounding the high voltage fuses. A shutter swings down to block access to the high voltage contacts in the disconnected position. Closing the door rotates the assembly into the connected position. NOTE: Opening PT cubicles can cause simulated loss of voltage or ESF actuations.

Figure 3, 10/98 at CPS, while in Cold Shutdown Bus 1A1 was momentarily de-energized causing the loss of Shutdown Cooling. An operator opened the wrong PT compartment while attempting to replace fuses from a Tagout. DG 1 started.

Control Cubicle

The control cubicle is bolted to the top of the breaker/bus cubicle. It provides for control function items such as fuses, control relays, terminal blocks, mechanism operated cell switches (MOC), etc.

Figure 4

The control power fuse blocks are designed such that they can be inserted upside down as a "storage" position when it is desired to have the control power deenergized. This practice is NOT allowed at CPS. This does provide an opportunity for human error, however.

IER 11-3 - Controlling plant evolutions precisely.

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-

STUDENT ACTIVITY
What human error reduction techniques can help to prevent putting a control power fuse block in upside down?

Breaker/Bus Cubicle

The breaker/bus cubicle is a welded assembly which contains the major functioning equipment such as the breaker, disconnect contacts, main bus and current transformers. It also contains the levering screw, shutter, interlocks and additional auxiliary switches.

Figure 5

Shutter and Barrier

Insulating barriers and an insulating shutter are mounted in front of the main contact supports. An operating arm is pivoted to the side of the breaker/bus cubicle and is linked to the shutter. The shutter is automatically raised by the action of a roller on the breaker against the cam surface of the shutter arm when the breaker is racked into to the connected position. When the breaker is racked out of the connected position, the shutter drops by gravity. The barriers and shutter, when closed, act as a physical barrier to the main contacts which may be energized. Opening the shutter exposes the main contacts. The shutter should not be removed or raised unless the main contacts are de-energized.

Figure 5

Main Bus, Main Bus Taps, and Ground Bus Contact

The conductors are made of copper. The main bus (bus bars), main bus joints and taps are insulated. The bus joints are silver plated and bolted. The main bus supports are porcelain. The main bus is accessible from either the front or the rear by removing bolt on covers only after the equipment has been de-energized. The breaker is connected to an extension of the ground bus as soon as it is put into the disconnected or the test position. It is continuously grounded as it is moved from the test to the operated position.

Levering-In Screw

The levering-in screw is a round threaded bar which is firmly attached to the rear of the breaker cubicle. It is positioned so that the thread is "aimed" toward the levering-in nut, which is part of the breaker. When the levering-screw and nut are engaged and the nut is rotated, the breaker is pulled into the connected position as the nut's rotation pulls the breaker along the length of the threaded levering-in screw.

Figure 5

[.1.4]

Guide Rail

The guide rail is a steel bar that is welded to the floor of the breaker cubicle. The guide channel on the bottom right hand side of the breaker engages the guide rail as the breaker is levered into the housing. The guide rail and channel position the breaker laterally in the housing.

Figures 5 and 7

The guide rail is notched at the front. The notch, in conjunction with the rail latch on the breaker, provides for a positive stop with the breaker in the test position. They also act together to prevent damage to the levering-screw when the breaker is pushed into the breaker cubicle.

Floor Trippers

There are two floor trippers on the floor of the breaker cubicle that serve three functions. Refer to Figure 5 during the following explanations.

[.1.11.1] Figure 5

The front floor tripper is a machined channel. The right leg operates the floor-tripping lever (interlock) on the bottom of the breaker to automatically trip the breaker when it is inserted or removed from the breaker cubicle.

[.1.4, .1.11.1]

The left leg of the front floor tripper operates the closing spring release lever (interlock) on the bottom of the breaker. If the closing spring is charged, it is discharged as the breaker is inserted into or withdrawn from the breaker cubicle.	[.1.9.1] [.1.15.1]
The rear floor tripper operates the floor tripping lever (interlock) to hold the breaker trip-free while it is traveling between the test and connected positions. This is to prevent accidental closing of the breaker while it is in the intermediate position. This is also known as the "anti-close" interlock.	[.1.9.1] [.1.15.2]
Auxiliary Switches	
Usually two "a" contacts and two "b" contacts are provided for breaker equipped with DC control power. The "a" contacts are normally closed when the breaker is closed and the "b" contacts are normally closed when the breaker is open.	
Mechanism-Operated Cell Switch (MOC)	
The MOC switch is an assembly of switches that is operated by a pin on the breaker mechanism. It is mounted on the right hand side of the control cubicle. It is operated by a lever which is connected to a vertical rod. The rod extends down into the breaker cubicle and connects to a pantograph on the side of the breaker cubicle. The pantograph is an assembly of a channel and levers. The pantograph is operated by a pin on the breaker mechanism. As a result, the MOC switch operates with the breaker contacts and can be used to electrically indicate whether the breaker is open or closed.	**Figure 4** [.1.9.2] [.1.17]
The MOC switch is operated when the breaker pin moves down as the breaker closes. The pin moving down pulls the MOC switch rod operating the contacts. In the test position the MOC switch can be operated with the breaker by pulling out the pantograph slide engaging the breakers operating pin.	
Truck-Operated Cell Switch (TOC)	
The TOC switch is an assembly of switches. It is mounted on the rear of the breaker cubicle. It is operated by a lever on the levering-in screw assembly. The lever is actuated by the breaker frame when the breaker is levered into the connected position. As a result, the TOC switch can be used to electrically indicate whether or not the breaker is in the connected position.	**Figure 5** [.1.9.3] [.1.11.2]

Breaker Position Interlock

The breaker position interlock is a device to prevent putting the breaker into the racked-in position. It stops the breaker before the levering-in nut can engage the levering-in screw. It is a mechanically operated assembly mounted on the lower right hand side of the breaker cubicle. The main part of the assembly is a formed round bar that is held in the unlocked position by a spring. The bar can be rotated into a notch in the guide rail and held in place by a padlock.

Figure 7 [.1.4]

Secondary Disconnecting Contacts

The secondary disconnecting contacts are the connections for the control leads between the removable breaker and the stationary breaker cubicle. The control wiring is arranged for drawout disconnecting by means of a 15-point female receptacle in the cell. The receptacle is arranged to connect to a male plug on the rear of the breaker. The female receptacle has a floating mounting and is located on the left rear of the breaker cubicle.

[.1.9.4] Figure 5

The plug on the breaker has two different size guide pins, and the receptacle in the breaker cubicle has two holes that match the guide pins. This arrangement of pins and holes polarizes the secondary contacts and aids in aligning them.

Breaker Coding Interlock

The breaker coding interlock prevents the insertion of a breaker into a breaker cubicle with a different rating. The coding system consists of an interference bar on the left side of the breaker frame and a notched coding plate bolted to the lower left of the breaker cubicle.

[.1.4] Figure 6
[.1.15.3]

B. Westinghouse Type DHP Magnetic Air Circuit Breaker

These breakers are removable interrupting elements for use in a horizontal drawout metal-clad switchgear.

They operate on the magnetic De-ion principle of interruption where the arc is elongated, cooled, restricted and de-ionized by the interaction of the arc and the transverse magnetic field produced by the arc current.

They are equipped with spring-stored energy closing mechanisms. Each circuit breaker consists of a breaker assembly, three interrupter assemblies (arc chutes), and a barrier assembly.

Breaker Assembly

The breaker assembly includes a chassis, a mechanism panel, a stored energy mechanism, a levering device, and various interlocks.

Mechanism Panel

The mechanism panel, located on the front of the breaker, contains the control items needed for circuit breaker operation. These control items include:

Figure 7

Breaker position indicator

MOC switch operating pin

Rail latch

Local Close and Trip plungers

Manual ratchet lever

Closing spring charged-discharged indicator

Secondary contact hand operating rod

Secondary contact handle

Levering-in device operating shaft

Content/Skills	Activities/Notes
Stored Energy Mechanism	
The spring stored energy mechanism performs two functions:	
a. It stores closing energy by compressing, or charging the closing spring.	
b. It applies the released energy to close the breaker and simultaneously charge the opening springs.	
Charging the Spring	
The spring is normally charged by the charging spring motor. The spring may also be manually charged using a maintenance handle which fits into a slot in the manual ratchet lever	**Figure 7** **[.1.9.5]** **[.1.16.1]**
Close and Trip Plungers	
Close and trip plungers allow the breaker to be operated locally. This would be done in only in unusual circumstances during which remote operation of the breaker is not available.	
A loss of DC Control Power to a breaker will result in both the loss of the automatic fault trips and as well as the ability to manually operate the breakers. It is not advisable to manually trip a breaker suspected of being in an overcurrent situation, this could result in personnel injury.	
When a breaker fails to respond to remote operation, local operation using the plunger is not normally used unless the associated bus if first deenergized.	
Levering -in Device	
The purpose of the levering-in device is to move the circuit breaker between the disconnected or test position and the connected or engaged position in the cell. The main parts of the levering-in device are:	**[.1.4][.1.9.6]**
• Levering nut	**Figure 7**
• Guide tube	
• Levering-in shaft	
• Levering-in interlock	

The levering nut is fastened to the guide tube and is loosely retained in a housing that is fastened to the rear of the breaker cubicle.

The operation consists of engaging the rotatable levering nut on the circuit breaker with the levering screw that is mounted on the rear wall of the breaker cubicle. By using the levering-in crank to rotate the levering screw, the breaker is moved between the connected, test and disconnected positions.

When the levering-in shaft is turned counter-clockwise the breaker will be withdrawn. When the levering-in shaft is turned clockwise the breaker will be inserted. When racked fully in, or when fully withdrawn, the crank will spin freely.

Levering-in Interlock

[.1.4] [.1.15.4]

The levering-in interlock is designed to prevent moving the breaker into or out of the connected position if the breaker contacts are closed. It consists of a movable key which can enter an elongated keyway in the front part of the levering-in shaft. The key is spring operated by the closing and opening movement of the breaker main shaft via the pole unit operating shaft.

When the breaker is closed, a force is applied to the key causing it to enter the keyway on the levering-in shaft. Since the key is pressing against the shaft, it will snap into the keyway on the first rotation of the shaft as the keyway comes into line with the key. This prevents further rotation of the levering-in shaft blocking the levering of the breaker.

If excessive force is applied to the levering-in shaft while the interlock key is engaged, the levering-in shaft pin, located where the levering-in crank is attached, will break allowing the crank to turn freely.

Guide Channel and Rail Latch

Figure 7
[.1.9.7]

The guide channel is an inverted U-shaped channel that is welded along the bottom right hand edge of the breaker chassis. The guide channel cooperates with the guide rail, which is welded to the floor of the breaker cubicle. The two pieces acting together position the breaker laterally in the cubicle.

The rail latch is located directly in front of the guide channel. It stops the breaker in the cubicle just before the levering screw and nut engage. It also holds the breaker in the disconnected or test position. This latch prevents damage to the levering-in screw and nut.

To lever the breaker into the connected position from the test position, the rail latch is pressed down and the breaker is pushed into the cubicle approximately one quarter inch so the levering-in nut and screw can be engaged.

When the breaker is levered out of the cell and the levering-in nut and screw have disengaged, the breaker should be pulled out approximately one quarter inch more to engage the rail latch, locking the breaker in the test position. With the switchgear door closed and torqued, this breaker storage location provides reasonable assurance that configuration control and the seismic qualification integrity of the switchgear is maintained.

The rail latch must be released to withdraw the breaker from the test position in the cubicle.

Secondary Contacts

The secondary disconnecting contacts are the connections for the control leads between the removable breaker and the stationary breaker cubicle. The secondary contact plug is mounted on a moveable bracket on the left side of the breaker chassis. This permits the contact plug to be extended to the rear with the breaker in the test position in order to make contact with the stationary receptacle in the breaker cubicle.

[.1.9.4] Figure 5

To engage the secondary contacts while the breaker is in the test position, lift the secondary contact hand operating rod enough to release it from the mechanism panel and push to the rear until the cross pin in the hand operating rod goes into the slots in the secondary contact engaging handle. The handle is then pressed down to make final engagement of the secondary contacts.

[.1.9.8]
Figure 8

Breaker Position Indicator and MOC Switch Operating Pin

The breaker position indicator is a lever assembly secured to the main shaft of the breaker operating mechanism where it projects through the right hand side of the breaker chassis. Movement of this lever is directly related to movement of the breaker mechanism and contacts. Open and Closed nameplates on the right side of the mechanism panel are located to indicate respective position of the breaker contacts.

Figures 4 and 7
[.1.10.3] [.1.10.4] [.1.11.3]

A heavy pin welded to the breaker position indicator lever projects to the right of the breaker chassis. As the breaker is levered into the cubicle this pin engages a channel member of the MOC switch mechanism. The MOC switch is operated by the pin each time the breaker is operated. At Clinton, MOC Switch engagement is optional in the test position, by way of a sliding channel in the pantagraph assembly.	**[.1.12.1]**
Floor Tripping and Closing Spring Release Interlocks	
The floor tripping and closing spring release interlocks operate to trip the breaker and discharge the closing spring when the breaker is inserted into or removed from the breaker cubicle.	**[.1.14] [.1.15.1] Figure 5**
Cam plates (channels) on the cell floor lift trip levers on the underside of the breaker. The floor tripping and closing spring release levers on the underside of the breaker are coupled to cams located on the breaker mechanism panel which operate to engage the breaker tripping and close spring release triggers.	
C. Cutler-Hammer DHP-VR Vacuum Circuit Breakers	
These breakers are removable interrupting elements for use in a horizontal drawout metal-clad switchgear.	
They are equipped with spring-stored energy closing mechanisms. Each circuit breaker consists of a breaker assembly, three vacuum interrupter assemblies and a barrier assembly.	
The major difference between the DHP and the DVP breakers are the vacuum interrupters used on the DVP breakers. The DVP breakers also have a second trip solenoid which is actuated by Recirculation Pump Trip (RPT) / Reactor Protection System (RPS) circuitry. These breaker are used for the RPT function to achieve a shorter period of time from actuation signal to arc suppression.	**[.1.13]**
The breaker cubicles on 781' Fuel Building are slightly different from the other 6.9KV and 4KV switchgear cubicles. Functionally the cubicles are the same.	**Figure 9**
The Local Close and Trip Plungers and the local breaker position indication are different on the Cutler-Hammer breakers but are functionally the same as the Westinghouse breakers.	**Figure 10**

Placing these breakers in test is slightly different due to the arrangement of the Secondary Contact Operating Rod. Whereas the Westinghouse rod is hinged to hang vertically, the Cutler-Hammer is hinged to swing horizontally. Also, the Secondary Contact Handle, which is pushed DOWN in the Westinghouse breakers to ensure solid contact, is instead pulled TOWARD the operator on the Cutler-Hammer.

Figures 8 and 11
[.1.13]

D. Westinghouse and Cutler-Hammer Breaker Control Schemes

If the control power fuses are installed, as soon as the secondary contacts make up, the spring charging motor will start to charge the closing spring. When the spring is completely charged the motor cut-off switch (LS/b) will open to turn the motor off and the LS/a switch will close. The LS/a switch is a permissive in the breaker close circuit. This switch prevents a closing attempt while the spring is charging.

Figure 12
[.1.2.1] [.1.14]

The breaker is closed by energizing the spring release (SR) coil on the breaker mechanism panel. This releases the closing spring to close the breaker. The SR coil is interlocked with the latch check switch (LC. SW). This switch ensures the closing spring is charged and latched prior to closing.

The breaker can be tripped by energizing the trip coil (TC) via the control switch or by action of protective relays. This releases the trip latch allowing the opening springs to open the breaker.

With the breaker in the test position, TOC switch contacts 3-4 and 7-8 are closed and contacts 1-2 and 5-6 are open. With the remote/local switch in local, contacts A6-B6 and C6-D6 are closed. Breaker control is now at the cubicle and the control room has no breaker control. Local breaker control via the local control switch requires the breaker to be in the test position as sensed by the TOC switch contacts and the remote/local switch in local. If desired, the remote/local switch can be placed in "remote" and the MCR has control via contacts A5-B5 C5-D5.

[.1.12.2] [.1.2.3] [1.3.1] [1.3.2]

With the breaker in the connected position, the control room has control of the breaker no matter what position the local/remote switch is in. TOC switch contacts 3-4 and 7-8 are open with the breaker racked in.

When the SR coil is energized, the breaker closes. When the breaker closes, auxiliary contacts 52/a close and 52/b open. The spring release coil de-energizes and the motor charges the closing spring again. The trip circuit is also set up when the breaker is closed.

dIf the control switch is held in the close position, the Y coil will energize. If the control switch is turned to close and released the Y coil will probably not energize. When the breaker is closed, the Y contacts set up what is called "anti-pumping." If the breaker trips while the control switch is held in the close position, the Y coil prevents a reclosure attempt.

In the racked out (disconnected) position, all control power is removed from the breaker.

[.1.2.2]

The red (breaker closed) indicating light is powered in series with the breaker Trip Coil (TC). Illumination of the red light is an indication that tripping power fuses are installed and power is available to the Trip Coil. This is a design feature that demonstrates tripping circuit integrity. The same case cannot be made for closing power through the observation of the green light.

STUDENT ACTIVITY

Using E02-1SA99-sheets 001 and 004, have all students analyze the drawing to determine how:

1. The automatic start of 0SA01C, the "0" Service Air Compressor is achieved. (On low pressure, SA11CR is energized, making up contacts that energized the closing circuit. This can only occur if the MCR switch is in the correct position)

2. The automatic trip of 0SA01C is achieved. (The compressor safety circuits energize 7CR, which energizes the Trip Coil for 0SA01C).

E. Westinghouse and Cutler-Hammer Breaker Local Operation

Control Power Fuses

Control power fuses shall be pulled prior to racking a breaker in, out or to test. A problem can be created when certain 6900 and 4160 volt breakers are racked out to the test position with the control power fuses installed and the auxiliary (secondary) contacts not made up. If the breaker is cycled remotely for testing or troubleshooting, the anti-pump (Y) coil remains energized after the breaker has been opened. Had the auxiliary contacts been make up the Y coil would have de-energized when the control switch is released. If the breaker is then racked in with the Y coil still energized, and an attempt is made to close the breaker, it will close but will immediately trip.

Breaker Racking Operations

CPS procedure 3515.01 contains operator actions for all 6900V and 4160V breaker operations and SHALL be used whenever performing these evolutions. Some figures in this lesson plan are also incorporated in 3515.01. Westinghouse and Cutler Hammer Breakers have the following racking evolutions performed on them:

- Placing a Westinghouse DHP or Cutler-Hammer DHP-VR Switchgear Breaker In The Racked-Out/Disconnected Position
- Placing a Westinghouse DHP or Cutler-Hammer DHP-VR Switchgear Breaker In The Test Position
- Placing a Westinghouse DHP or Cutler-Hammer DHP-VR Switchgear Breaker In The Drawn-Out/Removed Position
- Placing a Westinghouse DHP or Cutler-Hammer DHP-VR Switchgear Breaker From Drawn-Out/Removed To Test/Disconnected Position
- Placing a Westinghouse DHP or Cutler-Hammer DHP-VR Switchgear Breaker In The Racked-In/Connected Position

Figure 4-11

Using a copy of 3515.01 and the figures provided, review the interlocks and features while reviewing the various breaker operations covered. (If available, perform the racking operations at the Maintenance Learning Center, where a Westinghouse and a GE breaker are installed in cubicles with control power.)

Charging the Closing Spring Manually	**[.1.9.5, .1.16.1] Figures 7 and 10**
1. Place the end of the manual charging lever in the slot in the manual ratchet lever.	
2. Charge the spring with several downward movements of the lever until the lever suddenly turns freely and a positive metallic click is heard	
3. Remove maintenance closing lever	
Closing the Breaker Manually	
Note:	
There is an inherent safety concern when operating these breakers locally. This evolution is only performed as a last resort when a breaker MUST be operated to prevent damage to equipment or injury to personnel. Control logic functions associated with the control switch position and control power relays may be inoperative when manually operating breakers due to a loss of DC.	
Westinghouse Breakers:	
Place finger under the close-release magnet plunger marked "Lift to Close" and lift.	**[.1.16.2] Figure 6**
Cutler-Hammer Breakers:	
Press the "Push to Close" pushbutton	**Figure 10**
Note:	
When control power is not available for closing, it may also not be available for tripping. An evaluation of the hazards related to lack of tripping power must be made before closing the breaker under these conditions. (protective relays may operate to energize the trip circuit, but the breaker will not trip due to a lack of tripping power)	

Tripping the Breaker Manually

Westinghouse Breakers:

Place finger under the close-release magnet plunger marked "Lift to Open" and lift.

[.1.16.2] **Figure 6**

Cutler-Hammer Breakers:

Press the “Press to Open” pushbutton.

Figure 10

Interim Summary

Most of the high voltage breakers in the plant are the Westinghouse type. CPS has a history of problems concerning breakers not functioning properly; sometimes due to being improperly racked. Any difficulty encountered during breaker positioning must be reported immediately to avoid equipment damage or personnel injury. Having an understanding of the interlocks and control schemes will allow the operator to more quickly recognize when something is not working normally.

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General Electric Metal Clad Switchgear

Each unit is made up of a secondary and primary enclosure. The secondary enclosure is located at the breaker withdrawal side of the unit.

Secondary Enclosure

The secondary enclosure consists of a compartment with a hinged door upon which are mounted the necessary instruments, control and protective devices. The terminal blocks, fuse blocks, and some control devices are mounted inside the compartment.

Primary Enclosure

The primary enclosure contains the high voltage equipment and connections arranged in compartments to limit the effects of faults in order to minimize damage.

Potential Transformers

The potential transformers are located in a compartment above the current transformers. The transformers are mounted in a moveable carriage equipped with primary and secondary disconnecting devices.

Figure 13

When the potential transformers are disconnected, they are at a safe distance from all live parts of the switchgear. A grounding device is also provided which contacts the fuses when the potential transformers are disconnected. This effectively discharges the transformers. In this position the transformers may be safely removed.

Note the warning on the Div 3 Reserve Feed PT cubicle door:

CAUTION
OPENING DOOR COULD
CAUSE ESF ACTUATION

Breaker Elevating Mechanism

The elevating mechanism, for elevating or lowering the removable element to or from it's connected position, supports the removable breaker element in the connected position.

[.1.19.1]
Figure 14

In the test position the breaker is lowered to the guide rails and withdrawn from the fully inserted position approximately 2 1/4 inches.

The mechanism consists of heavy duty jack screws on which are carried nuts to support the elevating carriage. The carriage is designed so the removable element can be inserted or withdrawn after the carriage has been lowered to the disconnected position without removing any bolts or screws.

Guide rails are built into the metal-clad frame to guide the removable breaker element into the correct position before the breaker is raised to the connected position.

The breaker cannot be lowered or raised until it has been opened.

The breaker cannot be closed except with the breaker either in the connected or the test position.

There is no TOC switch associated with the GE breaker. Instead there are 2 limit switches that sense elevating mechanism position. The upper limit switch is made up when the elevation mechanism is fully raised and the lower limit switch is made up when the elevating mechanism is fully lowered.

4160V Div 3 Racking Device

[.1.19.2]

The Division 3 General Electric Magna-Blast breakers utilize an elevating motor to raise or lower the elevating mechanism. Due to the very high arc flash potential of the Division 3 breakers, CPS uses a SARRACS unit to perform this function.

The SARRACS unit consists of a gear motor mounted onto a mobile metal frame. The gear motor is vertically adjustable via actuator control on the SARRACS frame. The gear motor is laterally movable with linear spring loading. The gear motor incorporates a digital encoder for position control and sensing. The gear motor controls are located in a control box also mounted on the SARRACS frame. The SARRACS is controlled from a portable "operators station" connected to the SARRACS control box by a 75 ft communications/control cable.

When connected to the breaker/cell racking mechanism via the "Racking Adaptor" the gear motor is run CW or CCW as required to affect the "Racking" in or out of the breaker. The gear motor direction, speed, over current limits, ramp up and down times, etc. are controlled via the PLC program and the Variable Frequency Drive. Most of these values can be set via the Operators Touch Screen.

The operator defines the breaker starting position via the Operators Touch Screen. The Gear Motor Encoder and the PLC generate a linear counter to monitor and control the location and movement of the breaker as it moves from one position to the other. This linear counter is utilized to monitor the breaker position and initiate stopping of the motor at the proper final breaker position. The linear counter monitors and controls the breaker position to an accuracy of .001 inches. Travel counts and stop point counts are set via the Operators Touch Screen.

Gear motor over current protection and current limit are controlled by the PLC and the Variable Frequency Drive. These values are set via the Operators Touch Screen.

As the racking torque required for a breaker varies widely depending on its location (free travel, shutter operation, finger cluster engagement, etc), it is difficult to establish one over torque level that will adequately protect the breaker and cell during the racking process. The SARRACS solves this problem with its Profile Torque Protection. Utilizing the Gear Motor Encoder and the Variable Frequency Drive, the PLC generates a torque vs. position record for each individual breaker. This torque vs. position record (Torque Profile) is stored in the PLC Memory. Anytime a breaker is racked in or out, the PLC compares the active torque with the stored torque (Torque Profile) for that breaker. If the active torque is sufficiently greater than the stored torque, a " Profile Trip " is initiated and the breaker is automatically racked to the disconnect position. The "Torque Profile" can be updated via Operator Touch Screen commands. The level at which the " Profile Trip" is initiated can be set via the Operators Touch Screen.

Positive Interlocks

The positive interlock is located on the right hand side of the breaker cubicle. It has two functions:

[.1.20.1] Figure 16
[.1.19.3]

a. It prevents raising or lowering a breaker except when the primary contacts are open.

b. It prevents closing the primary contacts when the breaker is being raised or lowered by blocking the operating mechanism both mechanically and electrically.

There is a "V" in the upper and the lower ends of the positive interlock cam.

When the breaker is in the connected position the positive interlock roller should be centered in the upper "V". This releases the positive interlock allowing the breaker to be closed.

When the breaker is fully lowered the positive interlock, roller should be centered in the lower "V". This also releases the positive interlock allowing the breaker to be closed.

Spring Discharge Cam

[.1.19.4] Figure 16

The spring discharge cam is mounted on the left hand side of the breaker cubicle and operates in conjunction with a spring discharge interlock on the breaker.

When entering a breaker into it's cubicle, the spring discharge cam will hold the breaker trip free and the closing springs

[.1.20.2]

discharged until the breaker is approximately one-quarter inch off the floor. At this point the positive interlock is blocking charging of the closing spring and holding the closing circuit open.

While the breaker is being lowered the closing springs are still charged but the positive interlock blocks the breaker from closing. When the breaker is approximately one-quarter inch from the cubicle floor the spring discharge interlock holds the breaker trip free. This discharges the closing springs and holds them discharged as long as the breaker is in the unit.

To operate the breaker in the test position, it is pulled forward (out of the cubicle) approximately 2 1/4 inches until a notch in the spring discharge cam releases the breaker interlock. The breaker can then be operated manually or by assembling the test coupler, electrically.

Breaker Interference Stops

Stops are provided in the breaker cubicle to prevent the insertion of a breaker with a different rating. The stop plate is bolted to the left side of the cubicle frame near the floor. A projection on the breaker frame will interfere with the cubicle stop plate if an attempt is made to insert a breaker with a different rating.

Auxiliary Switch

The auxiliary switch (52 STA on the prints) is located above the breaker. In the connected position, an operating plunger on the breaker will extend when the breaker is closed. The breaker operating plunger will make contact with and operate the auxiliary switch operating rod in the cell. The auxiliary switch serves the same purposes as the MOC switch for Westinghouse and Cutler Hammer breakers.

[.1.20.3] Figures 14 & 18

A mechanical jumper can be assembled between the two rods for auxiliary switch operation while the breaker is in the test position.

Auxiliary (Secondary) Contacts

The auxiliary contacts are the connections for the control leads between the removable breaker and the breaker cubicle.

[.1.19.5]

An auxiliary contact jumper cable is provided. With the breaker in the test position, this jumper cable connects the contact block on top of the breaker to the contact block in the cubicle.

[.1.20.4]

F. General Electric Magna-Blast Circuit Breaker

The magne-blast circuit breaker has two principle components; the breaker element and the operating mechanism.

The breaker operating panel, located on the front of the operating mechanism contains the following:

Figure 17

1. Breaker Open/Closed indication

[.1.20.5]

2. Breaker closing springs Charged/Discharged indication

[.1.20.6]

3. Breaker Trip Pushbutton
4. Breaker Close Pushbutton

Breaker Element

The breaker element consists of three similar pole units, each of which includes the current carrying parts, main and arcing contacts, interrupter, and an enclosed barrier system that provides insulation between poles, or phases and to ground.

The primary connections to the switchgear are made through ball contacts at the top of the breaker bushings.

Operating Mechanism	
The operating mechanism is a stored energy type designed for high speed opening and closing. The mechanism operates on d-c voltage.	
Closing and opening operations are controlled either electrically from the switchgear with the breaker racked down or remotely from the control room, or mechanically by the manual close and trip levers on the breaker.	
Spring Charging	
The mechanism has a high speed gear motor that compresses a set of closing springs through the action of an eccentric, ratchet and pawl assembly.	**Figure 15**
During the time the closing springs are being compressed a relay is energized to hold the closing circuit open. This relay remains energized until the springs are fully compressed and the control switch contacts are reset.	
The closing springs may be compressed manually if control power is lost. A 5/8" ratchet wrench can be used to rotate the eccentric in a counter-clockwise rotation until the indicator reads charged and the driving pawl is raised from the ratchet wheel. The use of a ratchet wrench provides for personnel safety in the event control power is restored without warning.	**[.1.21.1] Figure 17**
Closing Operation	
The breaker can be closed electrically by energizing the spring release solenoid or manually by pushing the close pushbutton.	
When the closing operation is complete and the closing latch is reset, the contact of the latch monitoring circuit closes. This permits the spring charging motor to energize and recharge the closing springs.	
During the closing operation the opening springs are compressed and held ready for an opening operation.	
Opening Operation	
The breaker can be opened either electrically by energizing the trip coil or manually by pushing the trip lever.	**Figure 17**

Trip Free Operation	
If the trip coil is energized while the breaker is closing, the breaker will re-open and the closing springs will recharge as soon as the breaker is closed.	
Spring Release Interlock	
The spring release interlock discharges the closing spring and opens the breaker when the breaker is withdrawn from or inserted into the breaker cubicle.	**[.1.19.6] Figure 16**
Positive Interlock	
A positive interlock and interlock switch are provided between the breaker and the switchgear to prevent raising or lowering the breaker in the cubicle while the breaker is in the closed position and to prevent closing operation when the breaker is not fully lowered or fully raised.	**Figure 16**
With the breaker open, as soon as it is raised off the floor of the cubicle or lowered from the connected position (roller not in VEE) the positive interlock roller is pushed forward by the shape of the positive interlock cam located on the right hand side of the cubicle. When the roller is pushed forward the breaker is mechanically blocked from closing and a limit switch is opened which electrically disconnects the closing circuitry.	**[.1.19.3]**
With the breaker closed, the positive interlock roller is mechanically prevented from moving. This prevents the breaker from being raised or lowered with the breaker closed.	

G. General Electric Breaker Control Schemes

Spring Charging

The spring charging motor circuit is interlocked with the 52/IS, 52/SM-LS and the 52/CL-MS switch contacts. The 52/IS contacts prevent raising/lowering of the breaker while in the closed position and to prevent closing of the breaker and operation of the charging motor except in the full raise or lower positions. The 52/SM-LS contacts are for the motor cut-off switch. The first set of contacts permit charging when the spring is discharged and the second set of contacts energize the 52Y (Anti-Pump Relay) to prevent breaker pumping if the breaker trips while a close signal is being maintained. The 52/CL-MS contacts monitor the status of the closing latch. If the closing latch does not reset, the CL-MS will prevent the charging motor from operating and continually discharging the springs. In the lowered position the latch is prevented from holding the springs by the spring discharge cam, except in the test position. With the breaker in the full raise or test positions the springs will charge as soon as the motor disconnect switch (TD) is turned on.

Figure 20
[.1.4]

Breaker Controls

The control room control switch is in the circuit at all times. The test switch at the breaker cubicle is interlocked with the 52LS/LOWER contacts. The test switch functions only when the breaker is in the fully lowered position.

Figure 21
[.1.4]

The closing circuit is interlocked for fully raised or lowered operation by the 52/IS contacts.

On a closing operation, the closing coil (52X) is energized to release the closing springs via the control switch, 52/IS, 52Y and 52/LC contacts. As soon as the springs discharge, 52/SM-LS contacts 1-2 and 3-4 close. When contacts 1-2 close, the closing springs recharge. When contacts 3-4 close, the 52Y relay is energized for anti-pump protection.

Upon closing, the 52/a contacts close and place the trip coil in the tripping circuit.

Unlike the Westinghouse and Cutler-Hammer breakers, the green indicating light for a GE breaker remains ON when the control switch is placed in Pull-to-Lock (PTL).

H. General Electric Breaker Local Operation

Breaker Racking Operations

CPS procedure 3515.01 contains operator actions for all 6900V and 4160V breaker operations and SHALL be used whenever performing these evolutions. Some figures in this lesson plan are also incorporated in 3515.01. GE Magnablast Breakers have the following racking evolutions performed on them:

- Placing a Div 3 4160V Switchgear 1C1 Breaker In The Racked-Out/Racked-Down/Disconnected Position — **Figures 14-19**
- Placing a Div 3 4160V Switchgear 1C1 Breaker In The Test Position
- Restoring a Div 3 4160V Switchgear 1C1 Breaker From The Test Position
- Placing a Div 3 4160V Switchgear 1C1 Breaker In The Drawn-Out/Removed Position
- Placing a Div 3 4160V Switchgear 1C1 Breaker From Drawn-Out/Removed To Racked-Out/Racked-Down/Disconnected Position
- Placing A Div 3 4160V Switchgear 1C1 Breaker In The Racked-In/Racked-Up/Connected Position
- Manually Connecting A Div 3 4160V Switchgear 1C1 Breaker (Loss of Control Power) — **[.1.21.2]**
- Manually Connecting A Div 3 4160V Switchgear 1C1 Breaker (Loss of Control Power)

Using a copy of 3515.01 and the figures provided, review the interlocks and features while reviewing the various breaker operations covered. (If available, perform the racking operations at the Maintenance Learning Center, where a Westinghouse and a GE breaker are installed in cubicles with control power.)

Interim Summary

The Div 3 bus and the Div 3 breakers are different from the Westinghouse/Cutler-Hammer equipment in form, but not in function. The operator will do significantly fewer racking evolutions for the GE equipment versus the Westinghouse/Cutler-Hammer. The operating procedure gives excellent guidance on all of the components and must be referred to during every racking evolution.

SYSTEM IMPACT/CONSEQUENCES

Failure to push the levering-in device back into the breaker cubicle prior to shutting the door on a Westinghouse breaker could cause wiring and relay damage. The device could come in contact with wiring and/or relays located on the compartment door.

[.1.18.1]

Failure to turn the motor disconnect toggle switch to on after racking in a GE breaker would make the breaker inoperable. The closing springs would not charge and the breaker would not close when required.

[.1.18.2]

There are interlocks on both the Westinghouse and GE breakers to prevent racking them into the connected position with the breaker closed; the levering-in interlock on the Westinghouse breaker and the positive interlock on the GE breaker. Improperly racking a breaker to the connected position by using excessive force could cause breaker damage. If a breaker were not correctly restored to service it would not function automatically or remotely.

[.1.18.3]

When racking any breaker to the connected position if the auxiliary/secondary contacts are not fully made up the breaker would be operable. The closing springs would not charge and the breaker would not close when required.

[.1.18.4]

OP-AA-108-106, EQUIPMENT RETURN TO SERVICE:

a. If a safety related 4160-volt breaker has been racked out then upon being racked in the breaker shall be functionally tested in the connected position.

b. If a safety related 4160-volt breaker has had its control power fuses removed, following reinstallation of the control power fuses the fuses shall be verified not blown. This may be done by verifying voltage on the load side of the breaker.

MA-AA-716-012, POST MAINTENANCE TESTING:

Any size/voltage breaker maintenance upon being racked in the breaker shall be functionally tested in the test or the connected position.

Per CPS 3501.01, HIGH VOLTAGE AUXILIARY POWER SYSTEM:

a. When verifying breakers racked in, verify that the charging spring motor circuit is energized.

b. Prior to racking out or in a 4160 or 6900-volt breaker remove the control power fuses.

c. The safety related Westinghouse spare circuit breakers in the safety related switchgear (Div I and Div II), or idle circuit breakers in any division, that are disconnected and left in the cubicle, shall be stored in the disconnect position with the rail latch engaged, the door closed and torqued when maintenance is not being performed on the breaker.

Refer to the following procedures prior to racking breakers in/out.

- SA-AA-129, Electrical Safety
- CPS 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program
- CPS 3515.01, Operation of 6900/4160/480V Circuit Breakers
- CPS 3515.01M001, 6900/4160/480V Circuit Breaker Diagrams

V. Interlocks

Breaker and Bus Interlocks

Interlocks associated with the high voltage busses and breakers are described in the "Components" section of this lesson plan. Other interlocks for individual applications are covered in the system lesson plans.

VI. Controls/Instrumentation/Power Supplies

A. Power supplies

All high voltage breakers use 125VDC from either a divisional or non-divisional source.

- 6.9 KV and 4KV Bus 1A are supplied by DC MCC 1E
- 6.9 KV and 4KV Bus 1B are supplied by DC MCC 1F
- 4KV Bus 1A1 is supplied from DC MCC 1A
- 4KV Bus 1B1 is supplied from DC MCC 1B
- 4 KV Bus 1C1 is supplied from DC MCC 1C

Additionally, each non-safety bus can be supplied with DC control power by removing the fuses from the "NORMAL" supply and inserting them into the "RESERVE" supply at the bus. The reserve supply is fed from the opposite non-safety DC source (the 1A busses alternate feed is from DC MCC 1F).

DC control power provides power for breaker position indicating lights. All high voltage breakers have indicating lights on their cubicle door and in the Main Control Room. Breakers with control switches on the Remote Shutdown Panel will also have indicating lights on that panel that are active only when control is from the Remote Shutdown Panel.

B. Controls and Instrumentation

Individual breakers will have their respective controls and associated indications covered in the system lesson plans for those loads.

C. Significant Annunciators

High voltage breakers have various alarms associated with them. All have an "AUTO TRIP" alarm. The following activity will familiarize the student with the control logic and allow him/her to determine what alarms a particular breaker has.

STUDENT ACTIVITY

Break the students into three groups. Provide each group with a copy of E02-1SA99 sheets 001 and 004).

Using the E02's for0SA01C, Service Air Compressor 0, have the students trace the control power and describe how the following annunciators function (each group gets one alarm).

AUTO TRIP SERVICE AIR COMPRESSOR (part of the common trip annunciator for window 5040-1A.

AUTO START SERVICE AIR COMPRESSOR 5041-6B

VII. Interrelationships

A. Support Systems

DC Control Power

[.1.7]

B. Systems Supported

High voltage circuit breakers support various systems by delivering or interrupting AC power to loads.

- Aux Power
  - Feeder Breakers to the 6.9KV and 4KV busses
  - Feeder Breakers to 480VAC Unit Subs
- Condenser Vacuum
- Condensate
- Condensate Booster
- Plant Air
- Feedwater
- Plant Service Water
- Circulating Water
- Drywell Cooling
- Plant Chilled Water
- Reactor Recirculation
- Residual Heat Removal
- Low Pressure Core Spray
- High Pressure Core Spray
- Control Rod Drive
- Fuel Pool Cooling

VIII. Technical Specifications

A. Safety Limits

There are no safety limits associated with these components.

B. Limiting Conditions for Operation (LCOs)

ITS 3.8.9 Distribution Systems-Operating

ITS 3.8.10 Distribution Systems-Shutdown

If a bus becomes INOPERABLE for seismic or other concerns, the appropriate Spec (3.8.9 or 3.8.10) is entered. Exact actions will depend on plant conditions and which bus is involved.

In addition, if a breaker is rendered INOPERABLE the component supplied via that breaker becomes INOPERABLE, and the associated Tech Spec(s) is/are entered. Exact actions will depend on plant conditions and which breaker is involved.

CPS 1014.11, 6900/4160/480V SWITCHGEAR/CIRCUIT BREAKER OPERABILITY PROGRAM contains requirements to track time that a switchgear is seismically unqualified. Exceeding the time limits results in the bus being declared INOPERABLE.

IX. Operational Characteristics

A. Precautions and Limitations

The following precautions are found in CPS 3515.01, OPERATION OF 6900/4160/480V CIRCUIT BREAKERS:

> PREFERRED LEARNING ENVIRONMENT
>
> At the training annex, have students point out the possible hazards associated with the breakers, which portions are normally energized, and which parts will physically move during operation.

- SA-AA-129, Electrical Safety shall be referred to when working on or near energized equipment.
- Stay clear of moving or pre-charged parts to avoid personnel injury.
- If a breaker has been determined to have tripped on a fault, or sticks in mid position between OPEN and CLOSED, or is unusually difficult to RACK IN or OUT, it should not be reset or closed without prior notification of SMngt and Electrical Maintenance to allow for preliminary investigation.
- Breakers should only be "swapped" to different bus cubicles by specific MWO/AR job step, or in emergencies.

  Notify Planning and NSED to update appropriate documentation to track circuit breakers if an emergency arises and breakers must be swapped between cubicles.
  When "swapping" breakers or installing a spare DHP-VR, the 'snubber bolt' and 'sure close' mechanisms must be adjusted to match the settings for the new cubicle.
- The 1E22-C001 is a GE 4160V Magna-Blast breaker, which when in the TEST position is prone to movement due to is resting on its wheels.

  If the breaker is moved even slightly, the spring discharge cam ('V' notch) actuates a mechanical breaker trip interlock, tripping the breaker and holding it in a trip-free condition.
  Metal non-skid wheel chocks, wedges placed against the front wheels, are required whenever the breaker is in the TEST position to prevent breaker movement from the mechanical shock of operating.

X. Operating Experience (OPEX)

Given applicable operating experience, describe the lessons learned to prevent similar occurrences in accordance with the training materials and applicable procedures.

CIRCUIT BREAKER RELIABILITY

(Based on CR 1-98-10-031 and portions from INPO SOER 98-2)

According to INPO SOER 98-2, at least 60 breaker failure events have been reported. Over 10% of them were significant, resulting in plant scrams, forced shutdowns, major equipment damage, or safety system unavailability. Despite the attention the industry has placed on circuit breakers, there still occur events where circuit breakers failed to operate properly because of dried grease or lack of lubrication, a preventive maintenance procedure that did not include all the steps needed to address critical clearances and adjustments, or the preventive maintenance frequency that was not adequate to prevent a failure before normal wear became a factor. The most frequently documented cause for circuit breaker failures is degradation of lubricants.

Some plants have tried to address the complexities of circuit breaker preventive maintenance, testing, and refurbishment by sending their circuit breakers to vendors. It may be surprising to learn, however, that almost half of the reported circuit breaker events occurring between 1996 and 1998 involved some form of vendor performance error during these activities. When a circuit breaker is sent to a vendor for refurbishment, the condition of that circuit breaker is still the responsibility of plant personnel. Many of the circuit breakers described in the following events were installed in plant systems without being properly checked to see if they worked after receipt from vendors.

A. Westinghouse 4,160-Volt Circuit Breaker Failure and Investigation

Clinton, August 1997 (event 461-970805-1, CR 1-97-08-223)

Read the description of the event on page 1 and 2 Attachment A, and respond to the following questions.

1. Be able to explain the sequence of integrated plant events?
2. What direct causes are identified in the event description?
3. What would have been different if the plant had been at power at the time of the event?

B. Opening Incorrect Electrical Cubicle Causes Loss of Shutdown Cooling

Event Number: 461-981018-1, Opening Incorrect Electrical Cubicle Causes Loss of Shutdown Cooling and Failure to Meet Required Actions in the Required Time

Read the description of the event on page 3 of Attachment A and respond to the following questions.

1. Be able to explain the sequence of events?
2. What operator mindsets are identified in the event description that contributed to the error?
3. What behaviors would have prevented this event?

IER 17-005:

Ineffective operator fundamental performance led directly to loss of shutdown cooling (Line of sight to the reactor core).

-
-
-
-
-
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If the Procedures Are Not Right, Neither is the Maintenance

Preventive and corrective maintenance procedures, work package instructions, and drawings have, at times lacked the technical guidance needed to conduct effective maintenance. Due to the complexity and diversity in circuit breaker designs, even knowledgeable and experienced maintenance personnel need accurate instructions and reference material to successfully maintain circuit breakers.

C. Reversed Polarity Causes A Load Center Breaker Trip Event

Event Number 352-980322-2

Limerick Unit 1, March 1998

Read the description of the event on page 4 of Attachment A, and respond to the following questions.

1. Which purpose of high voltage breakers does this relate to?
2. What direct causes are identified in the event description?

D. OE14195 - EDG Output Breaker Failed to Close on Demand

Read the description of the event on pages 5 and 6 of Attachment A, and respond to the following questions.

1. Which purpose of high voltage breakers does this relate to?
2. What direct causes are identified in the event description?
3. What things can be mispositioned on CPS breakers that might cause a similar problem?
4. What human performance tools should be used to avoid this type of error?

XI. Conclusion/Lesson Summary

All major systems of the power plant require proper operation of the high voltage circuit breakers. Improper operation can result in having equipment fail to start or fail to deenergize when called on. This can result in having to take the unit off line and deenergize entire busses in order to protect equipment or personnel. Working around the high voltage breakers presents personnel hazards due to high voltages and moving parts. Using error prevention techniques and following sound safety practices can avoid plant transients and personnel injury.

Students should review the objectives, not the instructor. Instructors should read an objective and ask a student to tell the class what they know or learned about the topic. By having the students summarize the information, it provides the instructor as well as the students with a guide as to what's been learned and what needs additional emphasis.

Attachments

Attachment A-OPEX

OPEX 461-970805-1

Event Title: Westinghouse 4,160-Volt Circuit Breaker Failure and Investigation

Event Summary: On August 5, 1997, with Clinton in cold shutdown, a 4,160-volt (50DHP350) Westinghouse circuit breaker for the A residual heat removal (RHR) pump motor failed to open when its control switch was taken to the stop position. The failure occurred as operations personnel were switching pumps to change the shutdown cooling lineup. The A RHR pump motor had to be deenergized by opening the feeder breaker to the division 1 safety-related 4,160-volt bus. The spring force that opens the breaker was insufficient to overcome friction within the breaker due to insufficient lubrication of the breaker contacts and upper operating mechanism. This failure mechanism can potentially affect the rest of the station's breakers of this type (80 breakers total, 26 of those are used in safety-related applications). On July 22, 1997, a failure to trip of a Westinghouse 4,160-volt breaker was inadequately investigated in that it involved limited inspection of a failed division 1 safety-related safety bus main feeder breaker (50DHP350). The cause of the failure was not conclusively determined. In particular, the breaker was not quarantined to help determine the failure mechanism before it was manually opened. As a result, station personnel were unable to determine the failure mechanism for the breaker. In an unrelated event later the same day, another breaker used in a non-safety related application failed to close. Also, on July 22, 1997, an error in the associated maintenance procedure was the cause of the component misadjustment. The procedure erroneously directed the technician to measure travel to the point where a moving arm just touched the limit switch, rather that the point where the limit switch acted on the contacts to cause a state change. Subsequent investigation found most safety-related latch check switches out of adjustment but did not affect circuit breaker operability. The station's investigation attributed the failure to ineffective maintenance practices and an ineffective corrective action program for identifying and correcting previous breaker problems. The preventive maintenance performed, under the preventive maintenance program, did not require lubrication of the main and auxiliary contacts in the circuit breakers as recommended by the circuit breaker manufacturer and also did not provide sufficient instructions to remove the roughness on the main and auxiliary contacts. The preventive maintenance procedure did not include all vendor recommended lubrication requirements for some critical breaker components, including the breaker main and arcing contacts. This type of circuit breaker uses wedge-finger type contact assemblies where the moving contact penetrates the space between adjacent stationary mounted fingers. The potential for increased friction in this contact design makes proper lubrication critical to the operation of the breaker. In addition to the lack of regular lubrication, the station practice of cleaning the breaker contacts with freon removed any residual lubricating agents. As a result, the breaker contacts showed significant wear and galling, greatly increasing the friction between the contact surfaces. In addition, a periodic preventive maintenance task to refurbish the breaker was not established.

As a result, the breaker has been installed in the plant for 18 years without being refurbished. Indications of breaker performance such as routine timing measurements, tracking critical tolerances, and maintaining equipment history were insufficiently monitored. Comprehensive corrective actions are under development and will include performing maintenance on all 4,160- and 6,900-volt Westinghouse circuit breakers that are used in both safety-related and non-safety-related systems. This maintenance will involve inspecting, cleaning, lubricating, and testing each breaker. Particular attention is being paid to removing any roughness and lubricating the main and auxiliary contacts. The applicable maintenance procedures have been revised accordingly. A procedure is being developed that will preclude comparable concerns with other breakers. Also, the frequency for performing the preventive maintenance task on the breakers will be changed from once every six years to once every three years. On August 6, 1997, a team of circuit breaker manufacturer experts, independent circuit breaker experts, failure analysis experts and site maintenance and engineering personnel was formed to determine the cause of the circuit breaker to fail to open. After extensive inspection and testing of the circuit breaker, the team determined that the cause of the failure to open was the sum of the opening forces in the circuit breaker were not sufficient to overcome the friction from rough and unlubricated main and auxiliary contacts and degraded lubrication. This event is SIGNIFICANT because division 1 and division 2 electrical systems are affected by the breaker problem since they both use Westinghouse 4,160-volt breakers. This event is also recurring. SEN 169 dated September 11, 1997 was issued as a recurring significant event. This event could be indicative of precursors with the potential for future failures. The station considers this to be a serious degradation of the safety-related electrical system.

Event Title: Opening Incorrect Electrical Cubicle Causes Loss of Shutdown Cooling and Failure to Meet Required Actions in the Required Time Event Summary

Event Number: 461-981018-1

On October 18, 1998 with Clinton in cold shutdown, operations personnel restoring a tagout opened the wrong electrical cubical door causing the residual heat removal (RHR) A pump to trip. Opening the incorrect potential transformer fuse cubicle door resulted in the loss of offsite power to the division 1 bus causing a loss of shutdown cooling and coolant circulation for the reactor vessel. Technical specifications require that reactor coolant circulation be established within one hour of loss of shutdown cooling. At Clinton, the accepted alternate method of reactor coolant circulation in Mode 4 is by use of forced circulation. The status of these forced circulation systems was such that none of them were immediately available. It was determined that the most prudent success path for restoring reactor coolant circulation was the restoration of the A RHR system in the shutdown cooling mode of operation. Shift supervision referenced the reactor coolant time to boil curves and verified that time to boil was greater than 62 hours for reactor coolant, prioritized the recovery activities, and determined that restoration of the offsite power circuit was the immediate priority followed by restoration of reactor coolant circulation. Operations personnel entered the off-normal procedures for loss of AC power and loss of shutdown cooling and pursued restoring offsite power. The loss of shutdown cooling off-normal procedure directs the operator to maintain reactor coolant level greater than 44 inches using the shutdown range reactor vessel level instruments. This level ensures that there is natural circulation of reactor coolant even without forced circulation. At the time of this event reactor water level was already greater than 44 inches and therefore, natural reactor coolant circulation had been established. Reactor coolant circulation was established three hours and fourteen minutes after shutdown cooling was lost when the A RHR pump was started and placed into service in the shutdown cooling mode of operation. The cause of this event was initially attributed to a non-licensed operator opening the incorrect potential transformer fuse cubicle door. Subsequently it was determined that the procedure for restoration of reactor core circulation did not adequately support timely system recovery and that the crew's execution of the recovery activities was insufficient to meet technical specification requirements in a timely manner. This event is not significant because failure to restore reactor coolant circulation within one hour had little impact on core cooling due to the minimal decay heat load at the time of the event. Reactor coolant temperature increased three degrees Fahrenheit during the time it took to restore forced reactor coolant circulation. However this event is NOTEWORTHY because had this event occurred during reduced coolant inventory conditions, significant temperature stratification could have resulted.

Event Title: Reversed Polarity Causes A Load Center Breaker Trip Event
Event Number: 352-980322-2

Summary: On March 22, 1998, with Limerick Unit 1 operating at 100 percent power, the 124B-62 feeder breaker for the 124B load center tripped. As a result, all equipment from the load center was deenergized. The cause of the trip was the reversed polarity on one of three current transformers that input into the solid-state relay. This reversed polarity caused the trip setpoint to be as low as 831 amps compared to the normal value of 1600 amps plus or minus 10 percent. As a result of the above incident a methodology was developed to perform on-line testing of current transformers load center breakers for reversed polarity. To date approximately 130 breakers have been tested on-line and five have been removed from service. This event is not significant because of prompt operator response and use of appropriate operating procedures to mitigate potential consequences. This event is NOTEWORTHY because a power reduction to 85 percent was required to repair the degraded equipment. When the load center breaker tripped, another breaker tripped, an engineered safety feature actuation occurred and reactor water cleanup isolated. LER 352-98005 provides details on the sequence of events following the feeder breaker trip.

Subject: OE14195: EDG Output Breaker Failed to Close on Demand

Abstract: While attempting to operate the 'B' EDG output breaker to bus E-2 (breaker 52/27B) it failed to close as required. Investigation at the breaker cabinet revealed that the racking pin, which is pulled out prior to racking out the breaker was in its withdrawn position. The racking pin is a safety feature designed to prevent racking out a closed breaker, but it would also prevent the breaker from closing if it were engaged. After consultation with I & C shop electricians, the racking pin was pushed back in and the breaker subsequently operated successfully. Reason for Message: To make other utilities aware of human performance errors that led to unplanned unavailability of an important piece of safety equipment.

Event Date:...........................5/30/2002
Unit Name:............................Robinson Nuclear Plant
NSS/A-E:..............................Westinghouse / Ebasco
Turbine Manufacturer:.................Westinghouse
Maintenance Rule Applicability:.......No

Description:

Following preventative maintenance activities on the 'B' Emergency Diesel Generator, it was attempted to be paralleled onto the bus late on May 30, 2002. The breaker did not shut in response to its control switch position. A walk down investigation discovered the racking pin was withdrawn, preventing breaker operation. The racking pin was properly positioned and satisfactory breaker operation restored at 00:53 on May 31, 2002. Five hours and forty-one minutes of unplanned unavailability resulted. The Fire Protection AO (FPAO), a fully qualified Auxiliary Operator with 14 years of experience was assigned to remove the clearance on EDG "B". He and the Makeup Water Treatment Operator (MWTO), a fully qualified Auxiliary Operator with 7 years of experience, acting as a Peer Checker/Independent Verifier removed the clearance. As part of this restoration, the breaker for EDG "B" was racked in and the control power fuses restored. During the evolution of racking the breaker in, the racking pin was left in the withdrawn position. The procedure, OP-603-1, "Electrical Breaker Operation," states that this racking pin should be pushed back into the breaker. Neither the FPAO nor the MWTO noted that the racking pin was left in the withdrawn position. With the racking pin in the withdrawn position a mechanical interlock is activated to trip the breaker and maintain it tripped. Neither the FPAO, nor the MWTO reviewed the procedure, which was located on station. This was a routine operation performed under self-imposed time pressure near the end of the shift. The FPAO had been originally dispatched to restore HVE-15 but had been stopped and redirected to this job. The WCC SRO assumed the Control Room conducted a pre-job brief for the evolution. However, no pre-job brief was actually conducted for this evolution as would normally be expected when restoring an EDG to service. If this had been done, it could have served to concentrate the operator's attention more fully on the job of restoring the EDG.
The Peer Checker stated that he was not aware that the racking pin being in the withdrawn position had the affect of preventing breaker closure. There is no formal training lesson plan at the AO level for breakers. Currently the AO candidates train in the breaker lab in the Technical Training Facility (TTF) by racking the breakers in and out using the procedure. With past candidates, prior to the issuance of the procedure, they simply went to the facility and racked the breakers in and out via "skill of craft." Training instructors involved with this evolution stated that they were not aware of anyone specifically discussing the interlocks provided by the racking pin.

Had the effect of racking pin status been more firmly ingrained into the AO's knowledge, it is likely that its status would have been verified.
The independent verification performed was ineffective. The procedure clearly specifies that this breaker should have received independent verification. The individual performing the independent verification used little or no "time separation" between original task performance and performing the independent verification.

Causes:Root Cause:

The Operators performing the evolution did not reference the procedure prior to or during performance of the steps.

Contributing Causes:

1. The AO training program does not contain sufficient level of detail to assure that knowledge of the affects of the racking pin being withdrawn is disseminated.

2. The ineffective independent verification failed to assure the correct positioning of the breaker racking pin engagement.

3. The restoration evolution was conducted under self-imposed time pressure near the end of shift.

4. A pre-job briefing was not conducted for returning the EDG to service.

Corrective Actions:

1. The individuals involved have been counseled.

2. Each SSO has reviewed this event with their crew, discussed preventative methods for similar events, and reinforced clear expectations for independent verification.

3. Perform a training needs analysis of the AO training requirements with respect to breakers.

4. Reinforce expectations for performance of critical evolutions under time pressure and the need for a pre-job briefing with shift supervision.

5. Revise the Outside AO logs to provide a check for the DB-100 racking pins being inserted on buses E-1 and E-2 when EDG availability is required.

Licensee Event Report 2016-012-00

A. Plant Operating Conditions before the Event

Unit: 1

Mode: 1

Event Date: 12/05/16

Mode Name: Power Operation

Event Time:

Reactor Power:

2011

99 percent

B. DESCRIPTION OF EVENT

On December 5, 2016 at 2011 hours, Westinghouse DHP Breaker 1APO9EF for the Residual Heat Removal (RHR) "C" pump failed to close during the operability surveillance. During the test, the pump control switch was held in the start position for approximately 3 seconds with no indication of a pump start. When the control switch was released to the auto position, the pump trip indication illuminated. The RHR "C" pump was declared INOPERABLE and Technical Specification (TS) Limiting Condition of Operation (LCO) 3.5.1, "Emergency Core Cooling System-Operating", Required Action A.1 was entered to restore RHR "C" to OPERABLE status within seven days.

During the event investigation, the breaker charging springs were found to be charged and the latch check switch contacts open with the breaker installed in the cubicle. The function of the latch check switch is to indicate when the circuit breaker is "ready to close," providing a permissive for the breaker closure. In restoring the RHR "C" pump to OPERABLE status, the latch check switch was measured to be zero inches overtravel. The setting was adjusted to an overtravel value of 3/16 inch past the point that the contacts are closed as specified in plant procedures. Technicians that adjusted the latch check switch during the post event investigation indicated that the contact resistance was acceptable and the switch operated mechanically as expected. The mounting screws were subsequently verified to be tight following the failure. The breaker was placed back in service and post maintenance testing of RHR pump "C" was concluded satisfactorily. The RHR "C" pump was declared OPERABLE on December 6, 2016 at 0822 hours.

NARRATIVE

Breaker performance records indicate that the breaker was prepared for installation in the RHR "C" pump cubicle on January 19, 2016. The latch check switch setting was measured and recorded at 3/16 inch overtravel at that time. The breaker was installed in the RHR "C" pump cubical on March 11, 2016. On this date, the latch check switch setting before the installation was verified to be within specification but the value was not recorded. The most likely time that the switch would have become out of adjustment would have been during transport to the RHR "C" pump breaker cubicle on March 11, 2016. The latch check switch verification was not sufficient to identify an out of adjustment condition.

Following installation on March 11, 2016, the breaker operated satisfactorily on March 11, 2016, June 9, 2016, and September 6, 2016 prior to the failure. Since it is unlikely that the switch adjustment would change without breaker operation, it's assumed that switch contacts failed to close following the last successful surveillance test on September 6, 2016. Consequently, since the RHR "C" pump breaker would likely not closed since its last satisfactory surveillance on September 6, 2016 until the failed RHR pump operability surveillance on December 5, 2016, this constitutes a condition prohibited by Technical Specifications.

C. CAUSE OF EVENT

The cause of this event is that an inadequate latch check switch verification was performed prior to installation of the breaker into the cubicle. The required switch adjustment value of 1/8 to 3/16 inch past the point that the contacts are closed was verified but not recorded. As a result, a supervisory review of the switch adjustment value could not be performed and the out adjustment condition went undetected.

D. SAFETY ANALYSIS

There were no safety consequences associated with the event described in this report. The event is reportable under 10CFR50.73(a)(2)(i)(B) as an "operation or condition which was prohibited by the plant's Technical Specifications." Failure of the RHR pump "C" to start during the surveillance test was a condition prohibited by the TS; however, this surveillance failure did not adversely affect the ability the plant to safely shutdown in the event of an accident. When the pump was declared INOPERABLE, TS 3.5.1, Required Action A.1 was entered to restore it to OPERABLE status. RHR "C" was restored in approximately 12 hours. The RHR system safety function to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary was not jeopardized. Since RHR "A", "B" and low pressure core spray pumps remained OPERABLE during this event, a redundancy of plant components and features remained available to assure that operation the RHR system safety function could be accomplished.

E. CORRECTIVE ACTIONS

Actions have been initiated to revise plant procedures to ensure the tightness of the mounting screws of the latch check switch prior to measuring the adjustment value and record the latch check switch setting prior to breaker installation. A sample of completed latch check switch settings will be reviewed for similar inadequacies.

F. PREVIOUS SIMILAR OCCURENCES

No previous Event Reports were identified which detail an occurrence similar to the event described in this report.

G. COMPONENT FAILURE DATA

Manufacturer: Westinghouse

Component Type: DHP 6900, 4160 Volt Power Circuit Breaker

NRC FORM 366A (06-2016) Page 4 of 4

Figures

Figure 1
Westinghouse Switchgear-Front View

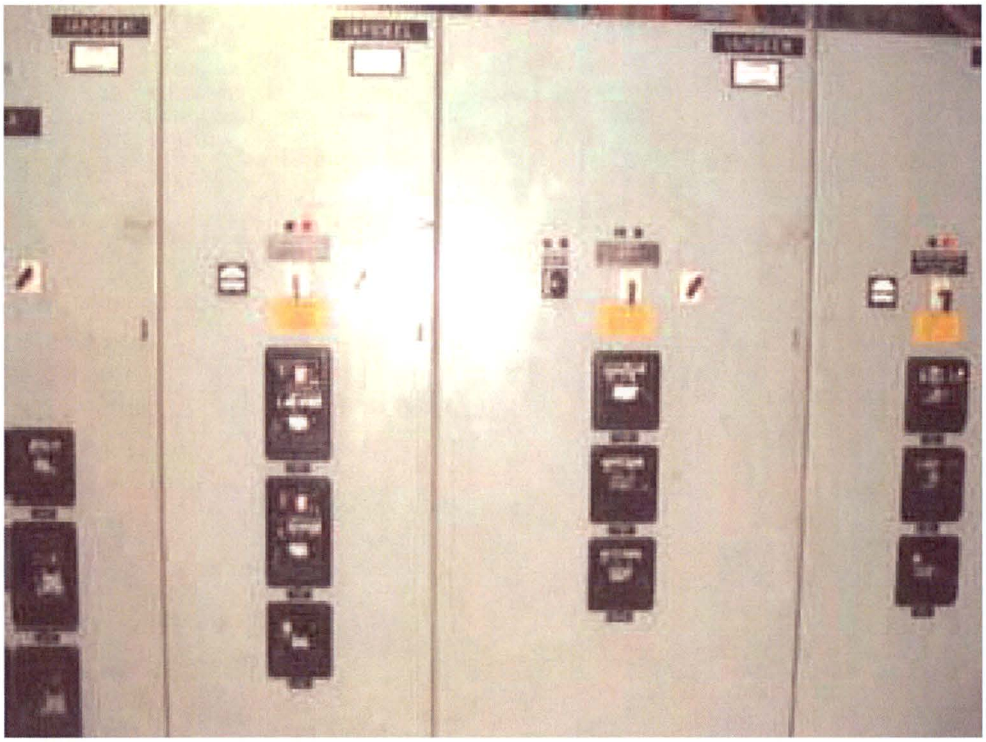
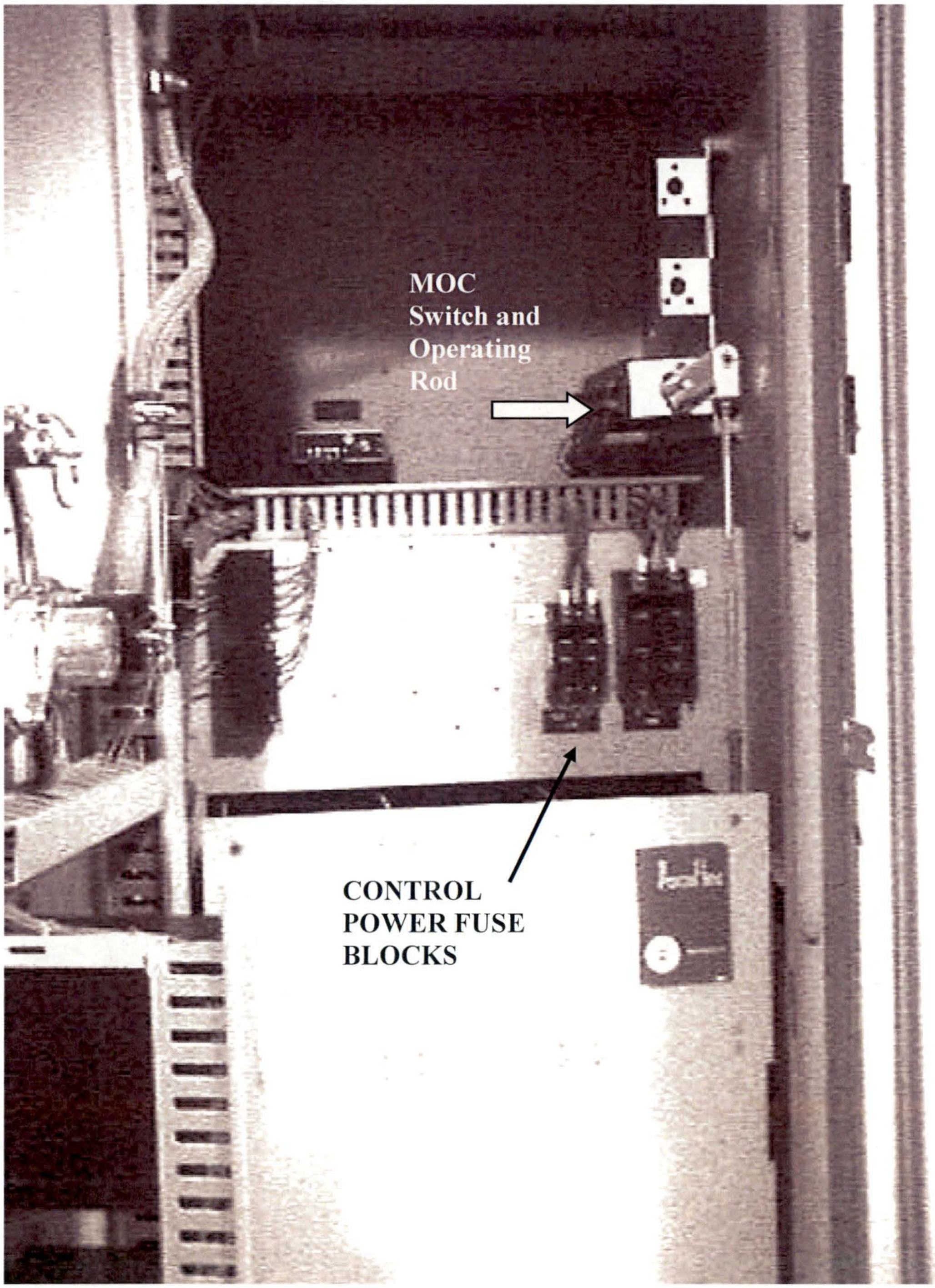


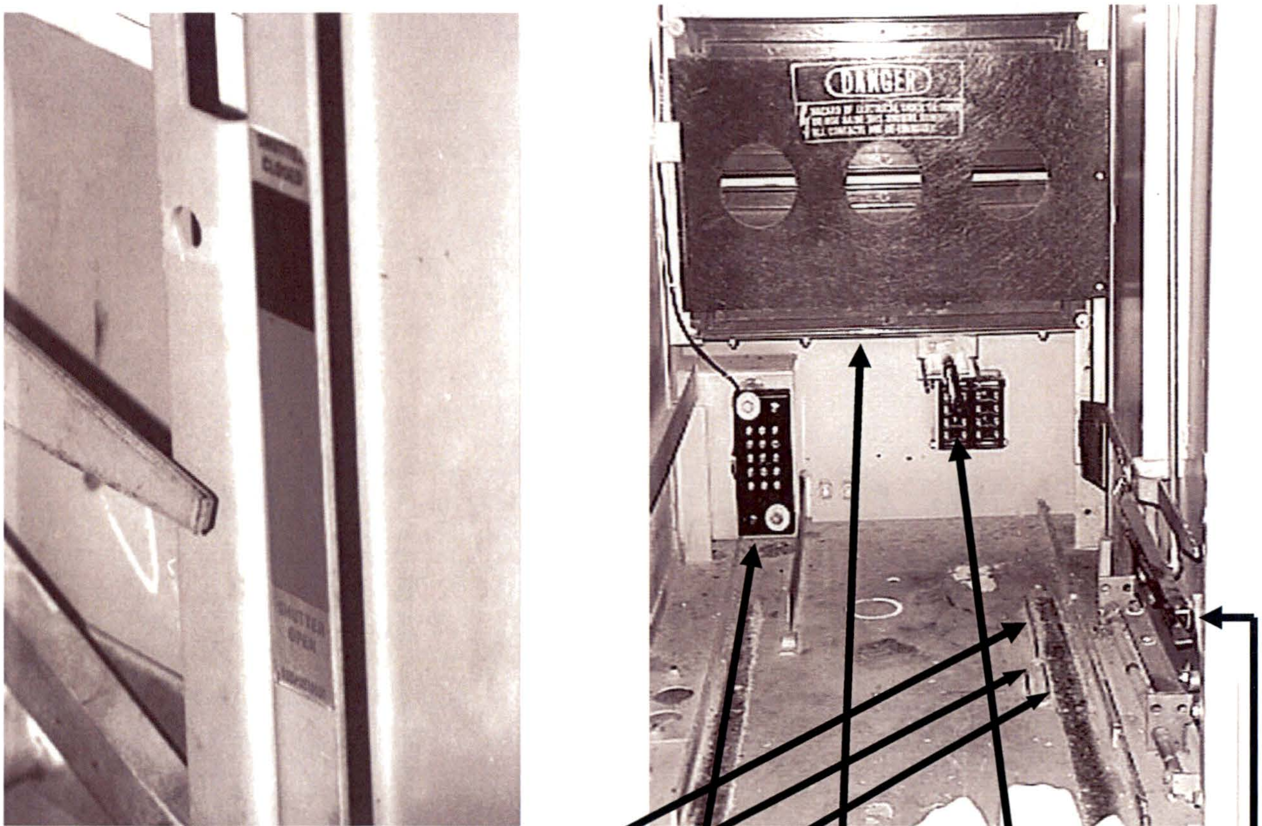
Figure 2
Westinghouse Switchgear-Rear View

WESTINGHOUSE (DHP) 6900V and 4160V Bus

Figure 3
Westinghouse Switchgear-Potential Fuse Cubicle

Figure 4
Westinghouse Switchgear-Control Module





Bus Shutter indicator (Bottom, front right side of Breaker Cubicle)

Rear Floor Tripper
Left Leg Floor Tripper
Right Leg Floor Tripper

Cubicle Secondary Contact Block

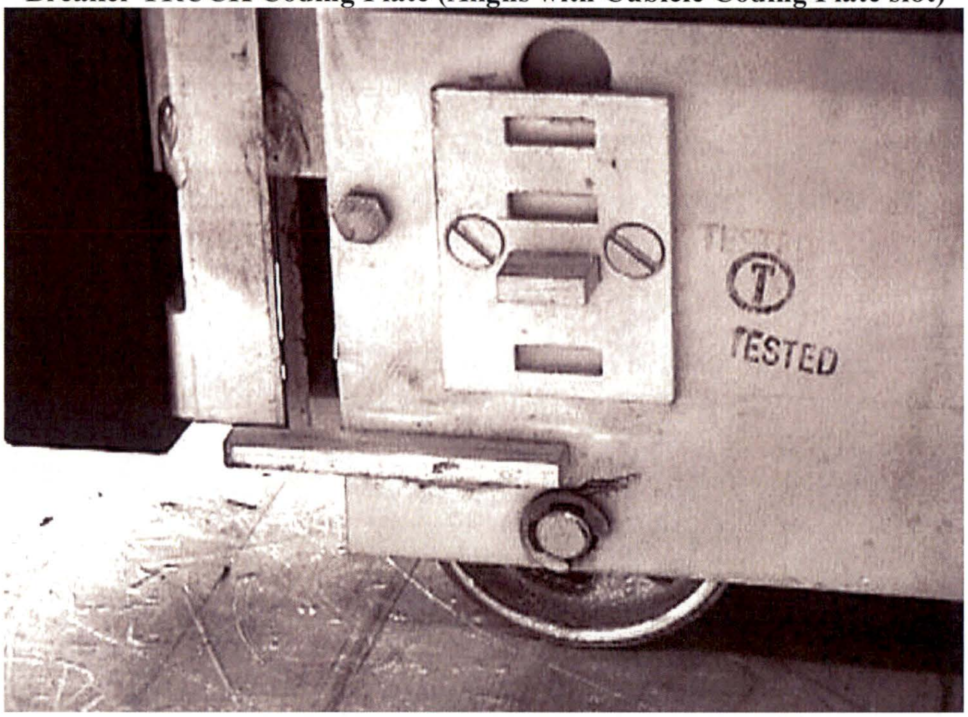
Bus Shutter in the SHUTTER CLOSED position.

TOC Switch and Cubicle Levering-In Screw

PANTOGRAPH Assembly Slot

Figure 6
Westinghouse Breaker Coding Plate

Breaker TRUCK Coding Plate (Aligns with Cubicle Coding Plate slot)



CIRCUIT BREAKER OPEN / RACKED-IN / CONNECTED POSITION

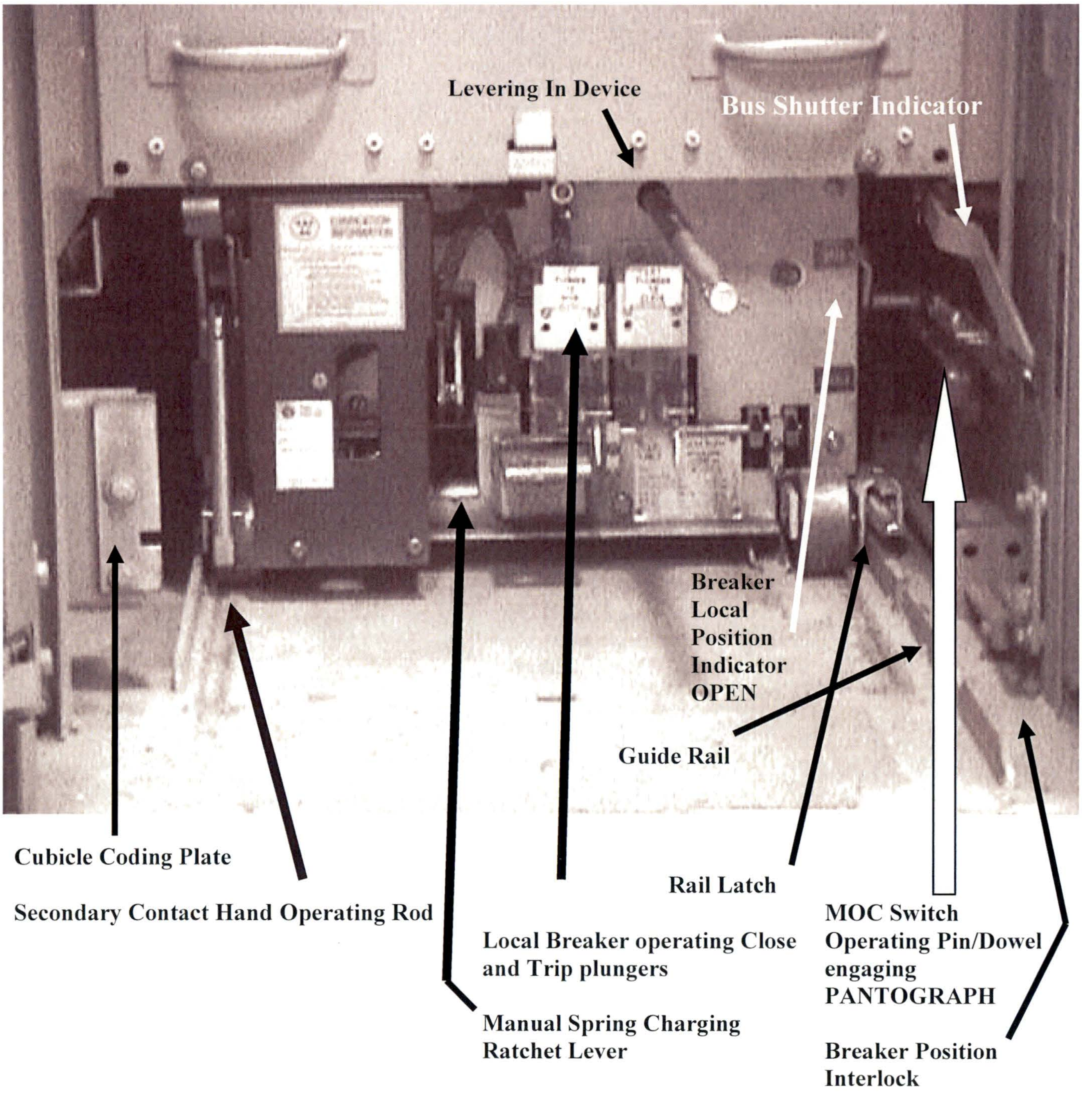
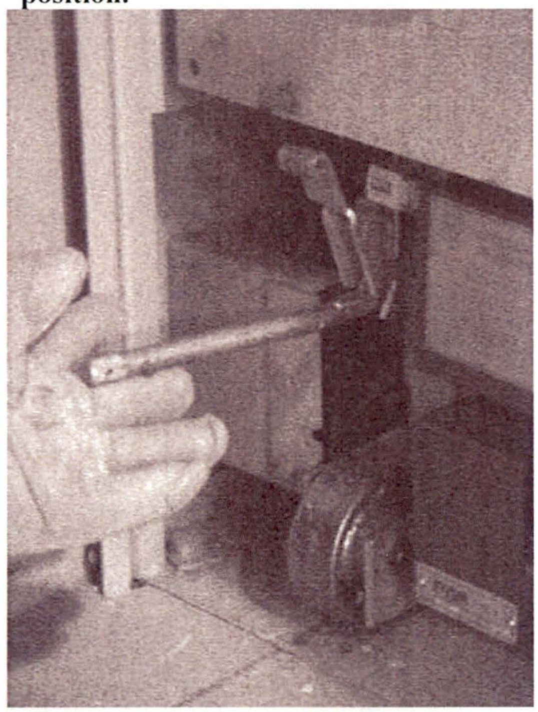


Figure 8
Placing a Westinghouse Switchgear Breaker In The Test Position

Lift and Insert Secondary Contact Hand Operating Rod until retaining pin enters the Engaging Handle slots.

Press Engaging Handle DOWN until it stops to engage the Secondary Contacts to Test the Breaker in the RACKED-OUT/DISCONNECTED position.



Breaker Closing and Trip Linkages. (Both shown down)

MOC Switch Operating Pin properly engaged in the PANTOGRAPH assembly Slot.

Figure 9
Cutler-Hammer Switchgear Cubicle

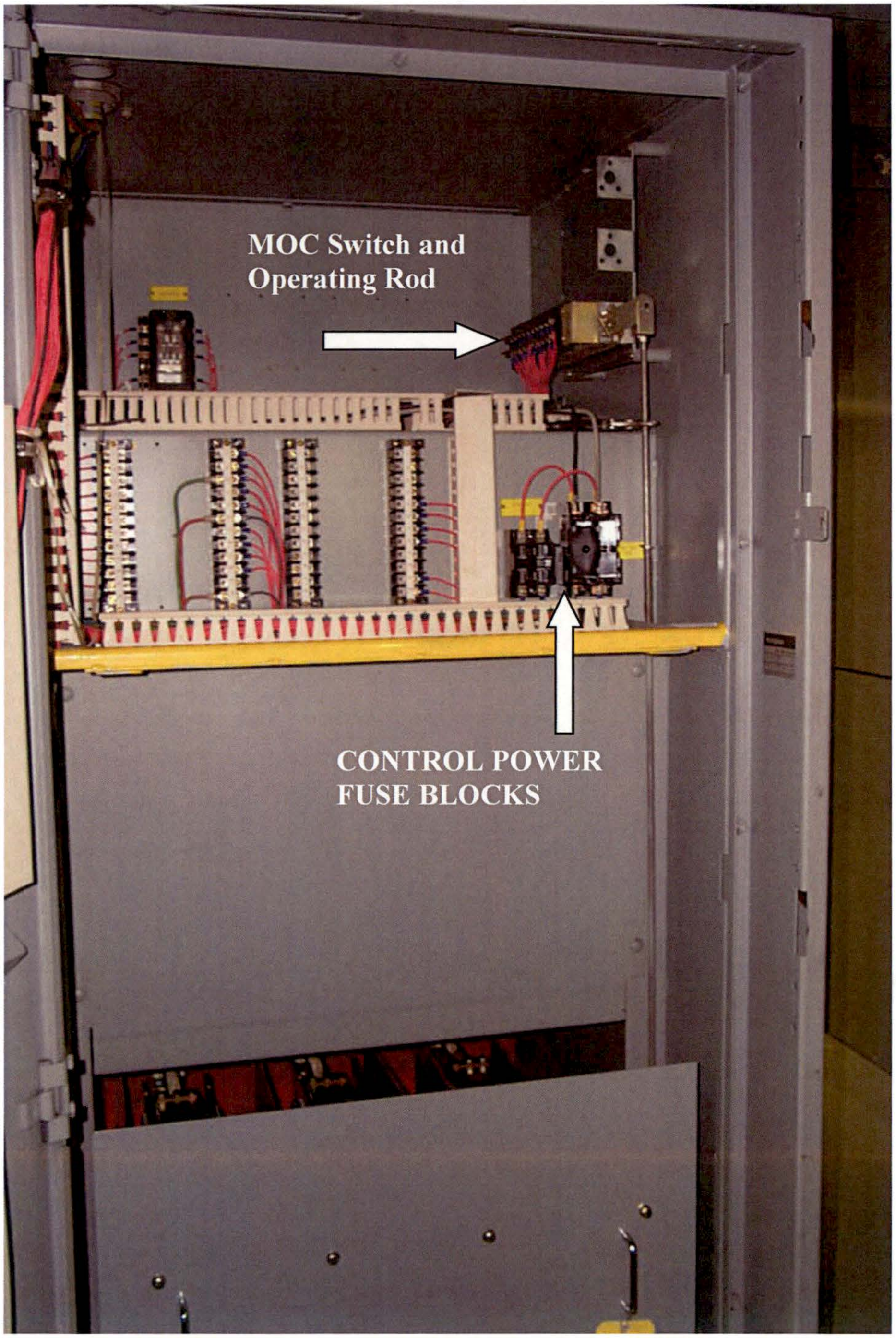


Figure 10
Cutler-Hammer Breaker Features

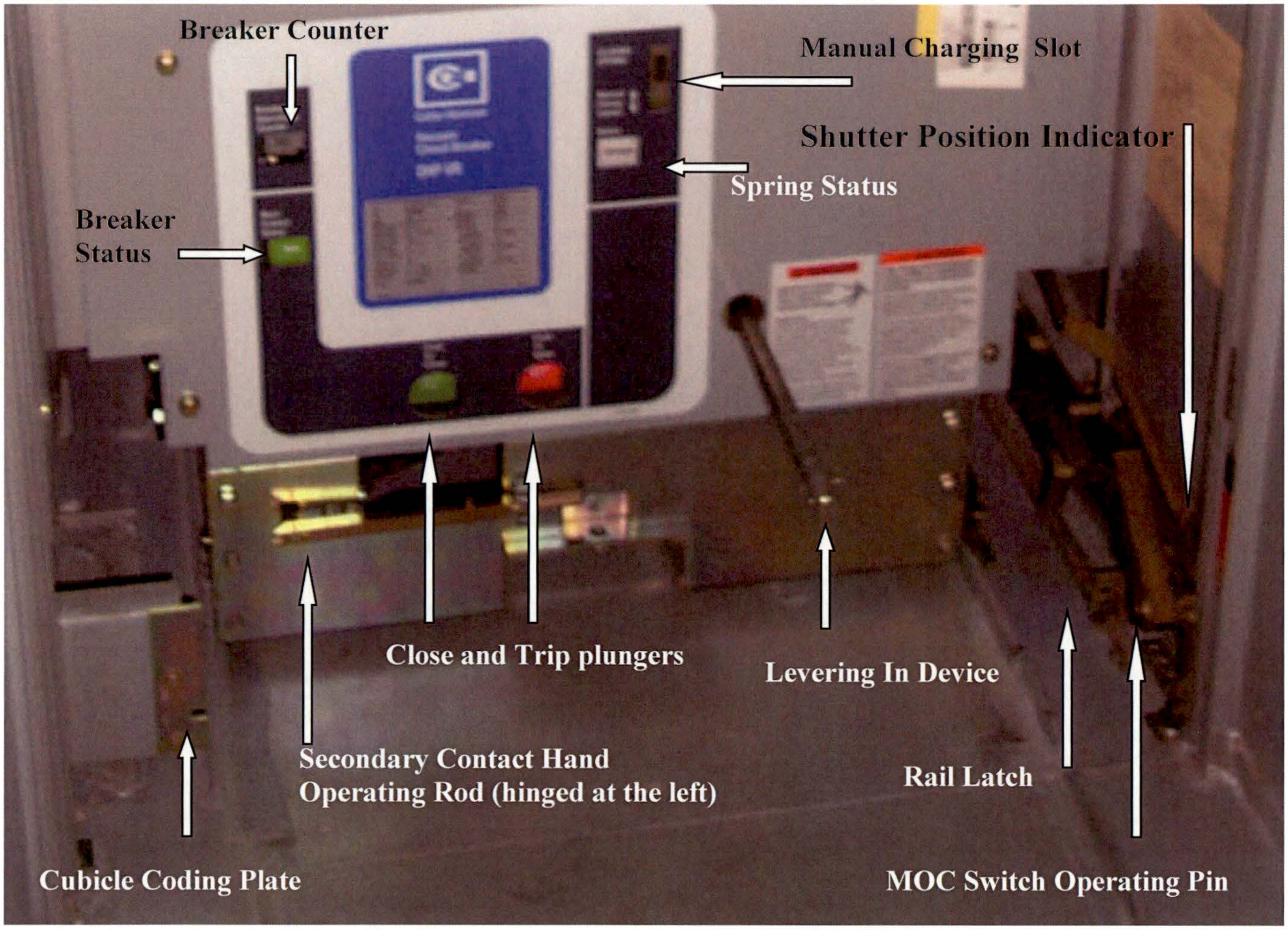
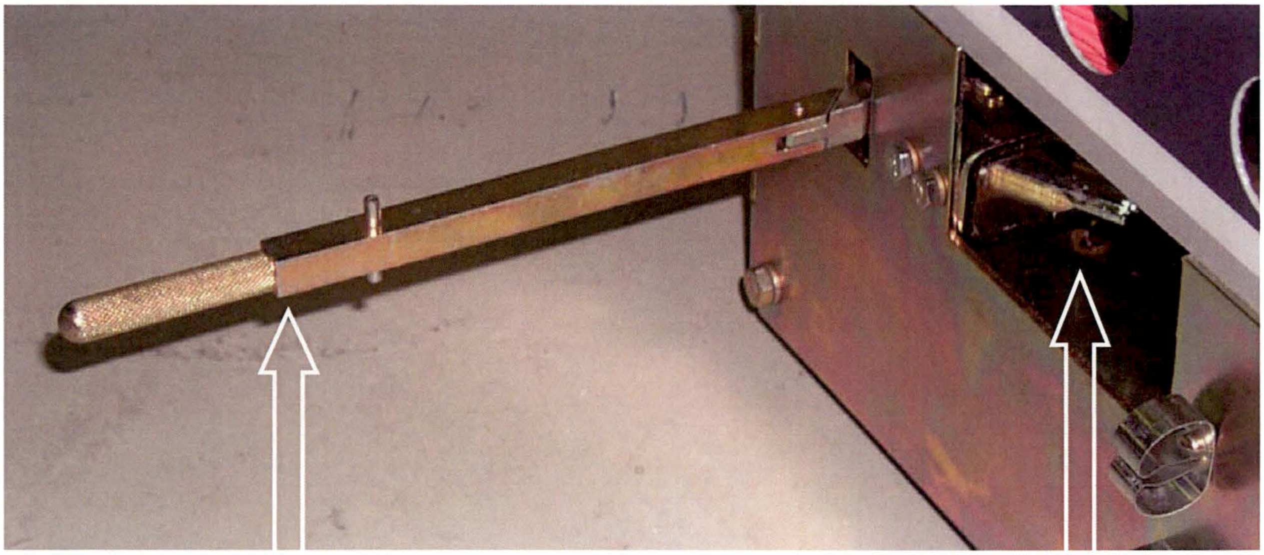


Figure 11

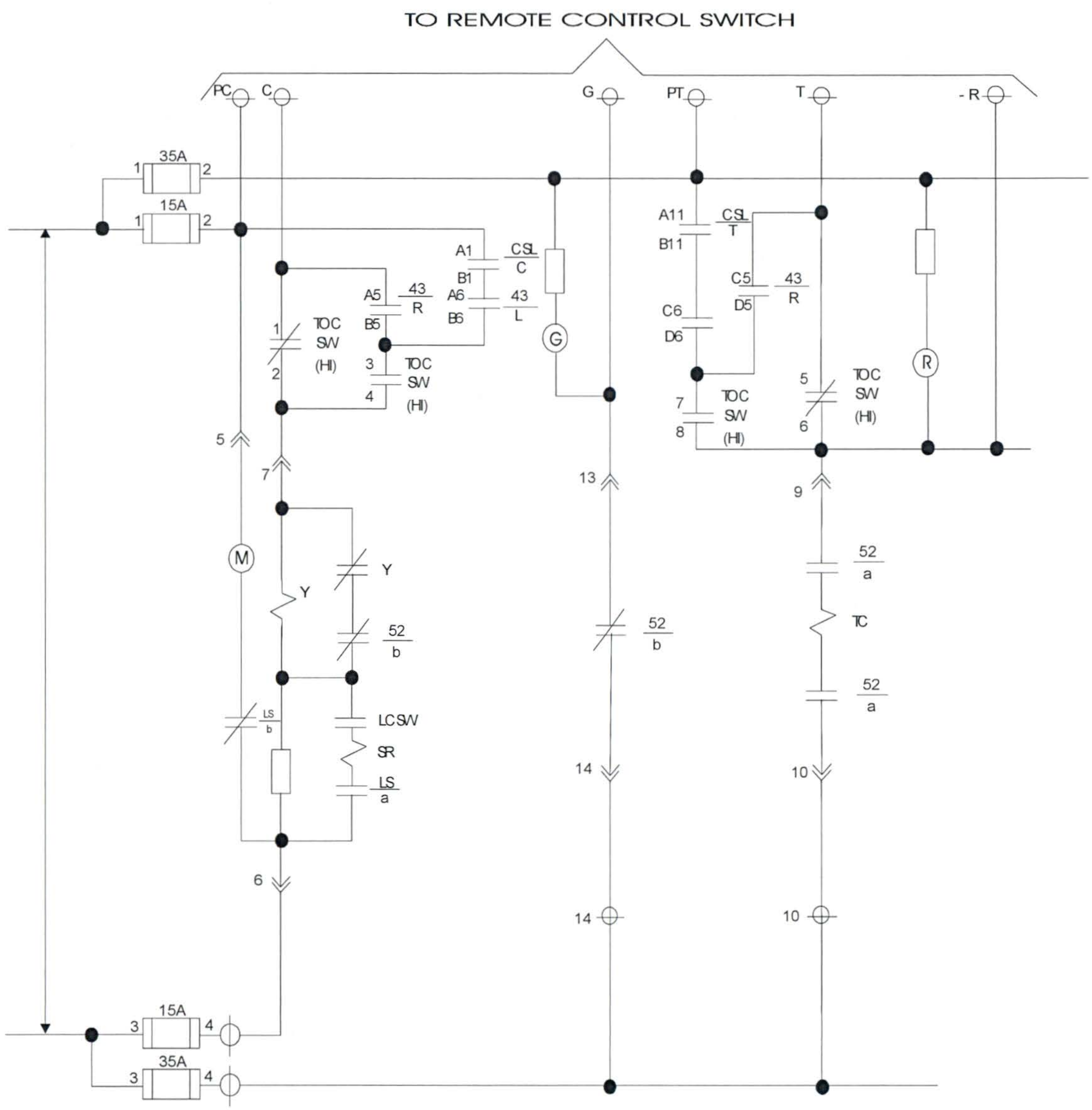
Placing a Cutler-Hammer DHP-VR Switchgear Breaker In The Test Position



Swing out and Insert Secondary Contact Hand Operating Rod until the secondary contacts are initially engaged.

Pull Engaging Handle TOWARDS you until it stops to engage the Secondary Contacts to Test the Breaker in the RACKED-OUT/DISCONNECTED position.

Figure 12
Westinghouse Breaker Scheme



WESTINGHOUSE BREAKER SCHEME

Figure 13
GE Potential Fuse Cubicle

Figure 14
GE Switchgear Cubicle

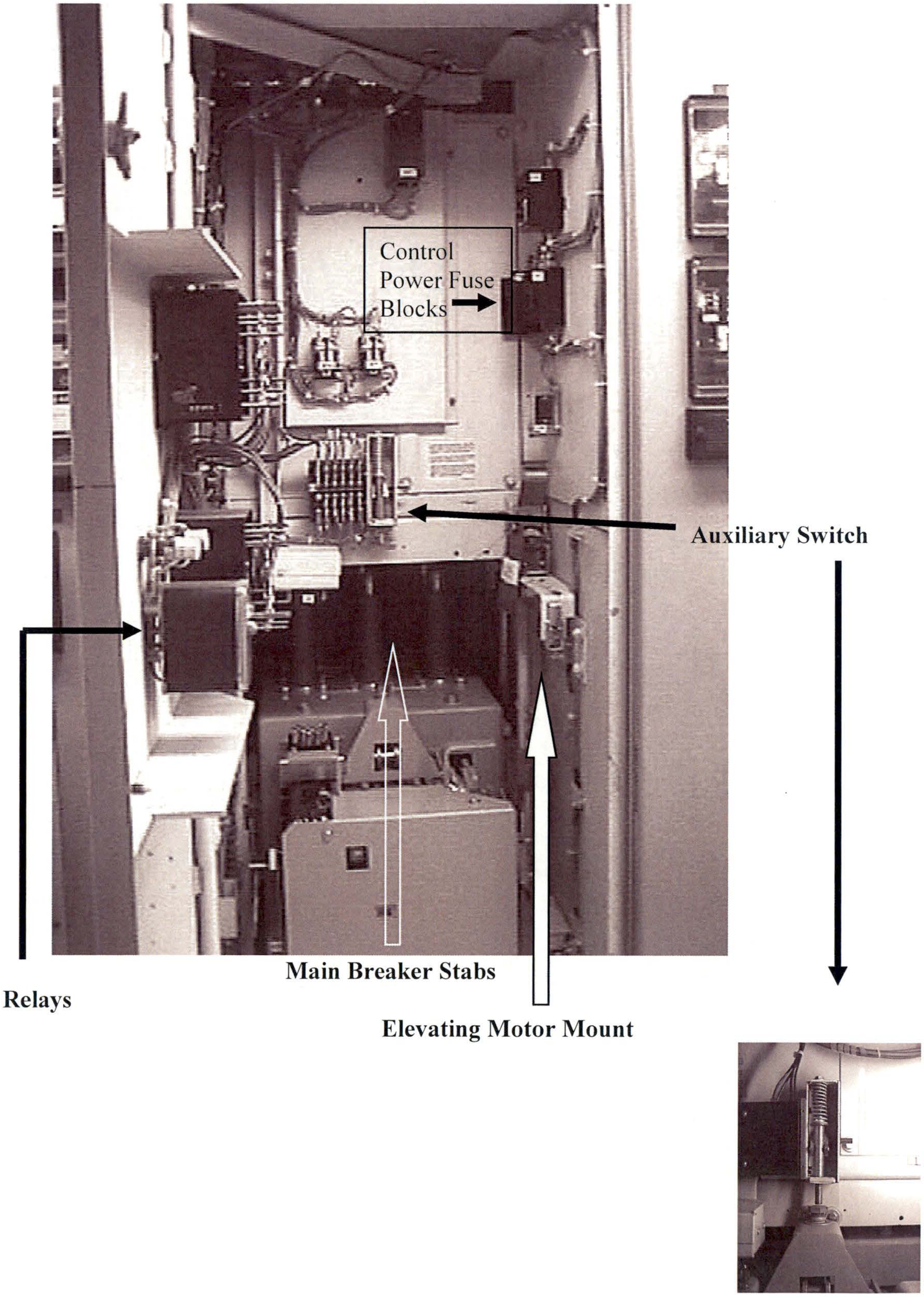
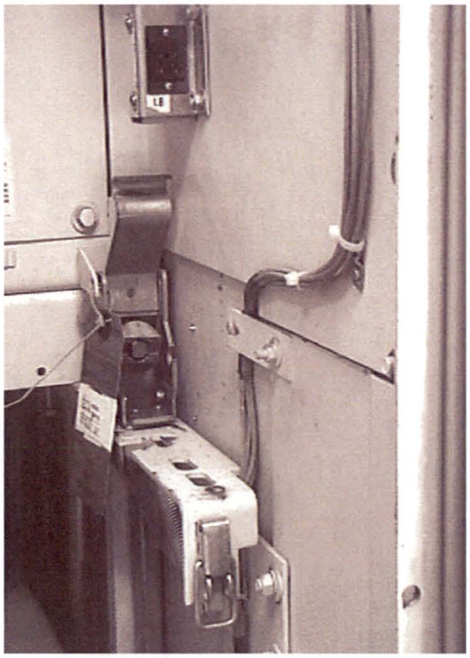
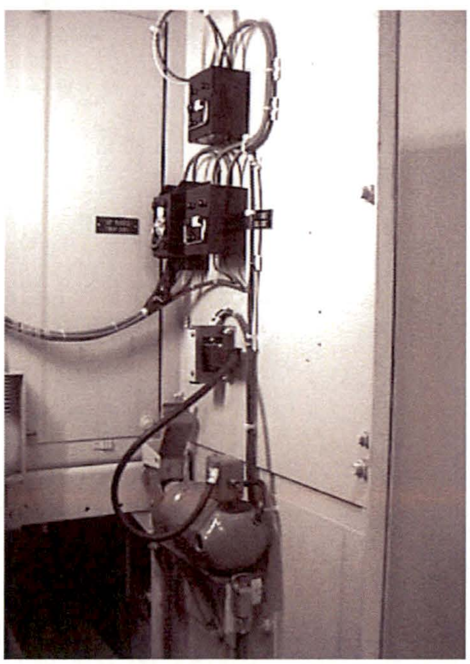


Figure 15
GE Magna Blast Breaker Elevating Motor

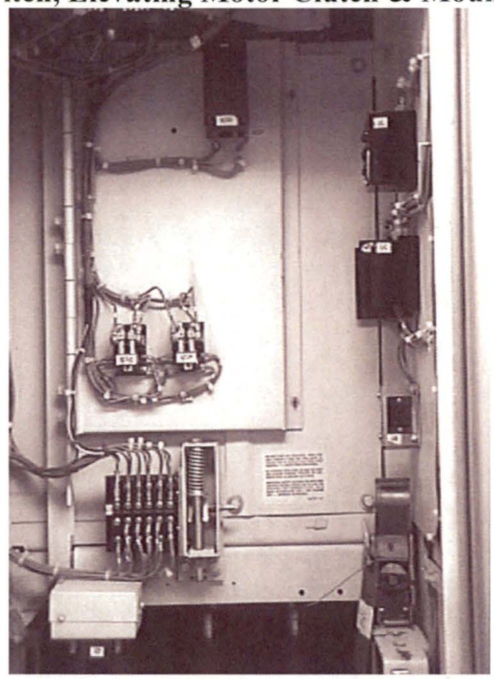
Elevating Motor Clutch Handle Support Bracket & Power connection

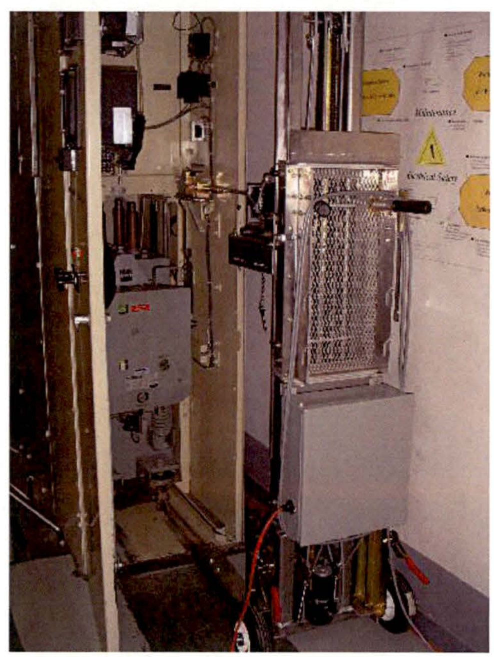




Breaker Control Power (CLOSE TRIP) Fuse Blocks

Relays, Control Power Fuse Blocks, Auxiliary Switch, Elevating Motor Clutch & Mount



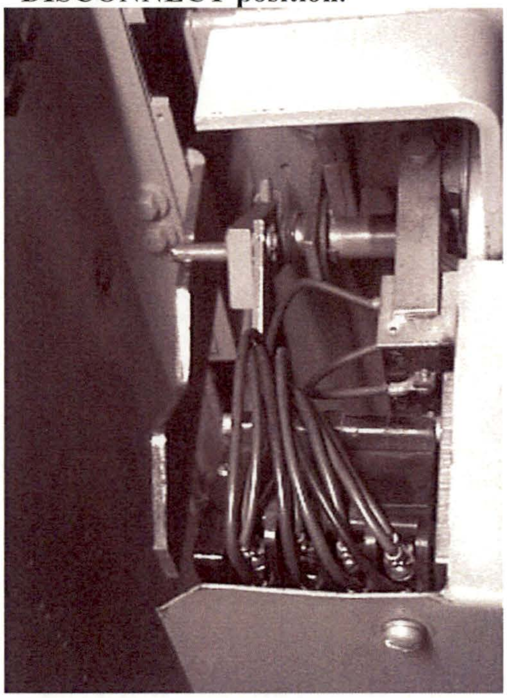


SARRACS Unit installed for operation

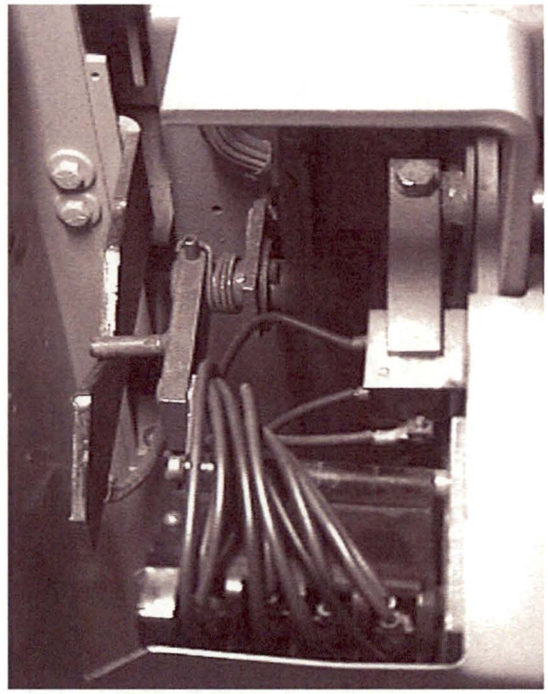
Figure 16

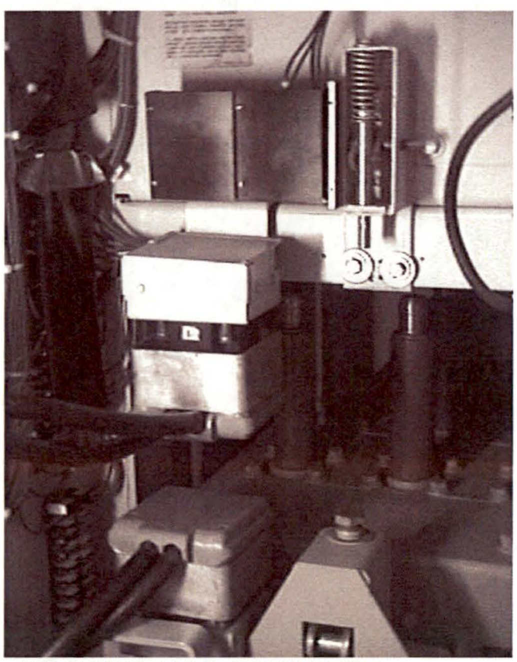
GE Magna Blast Breaker Interlocks

Spring Release Interlock with Breaker in the RACKED-DOWN / DISCONNECT position.

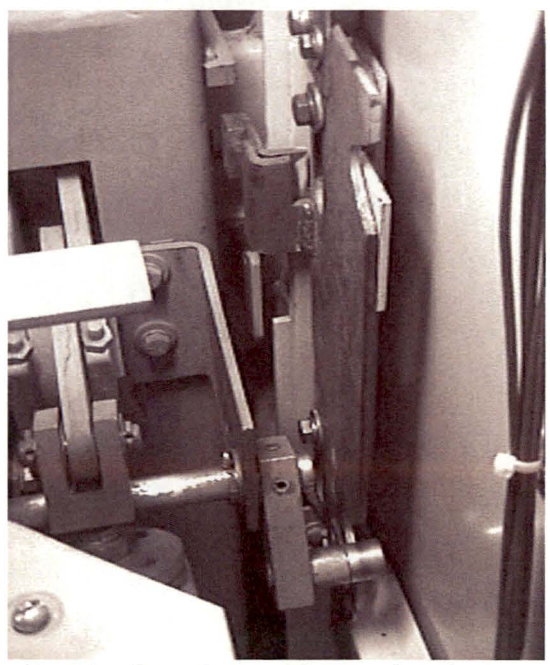


Spring Release Interlock with Breaker in the TEST position.



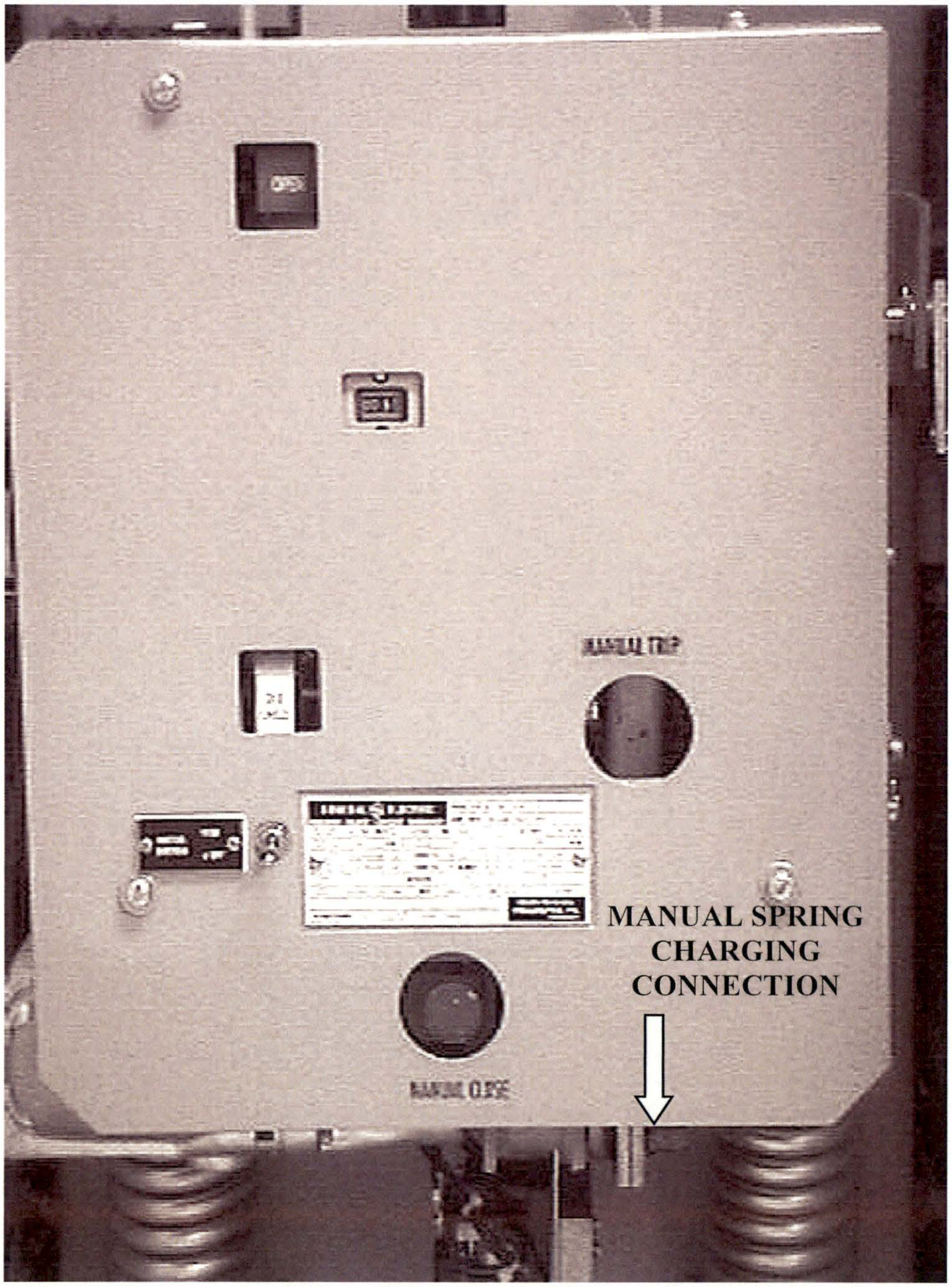


SECONDARY CONTACT JUMPER CABLE Installed between breaker truck and cubicle.



Positive Interlock with Breaker in RACKED-DOWN /DISCONNECT position

Figure 17
GE Magnablast Breaker-Front View



Breaker Face Plate: Bkr position, cycle counter, Closing Spring indicator, Manual Trip, Spring Charging Motor, Manual Close (Read from top left to bottom right)

Figure 18
GE Magnablast Breaker-Top View

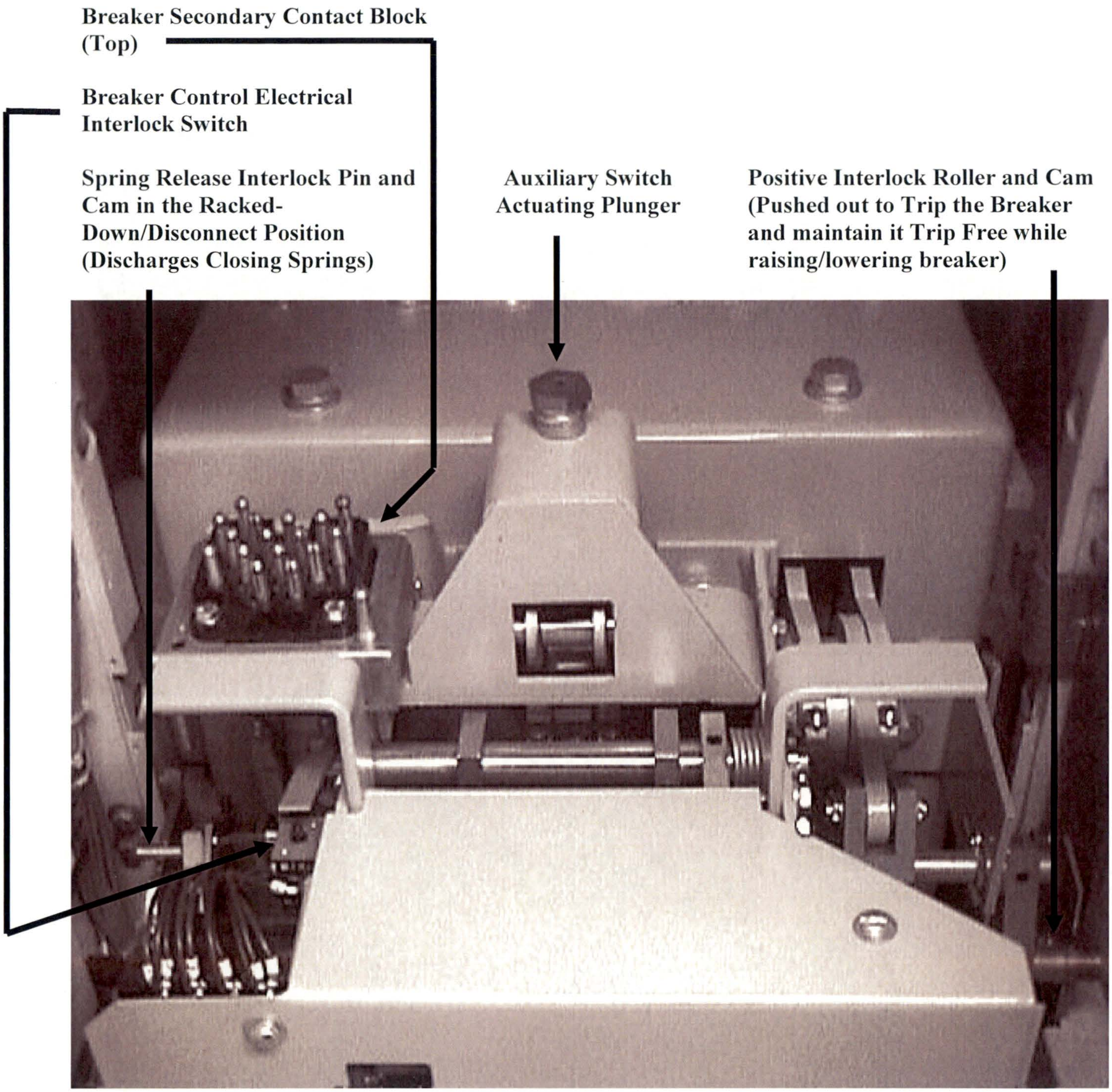
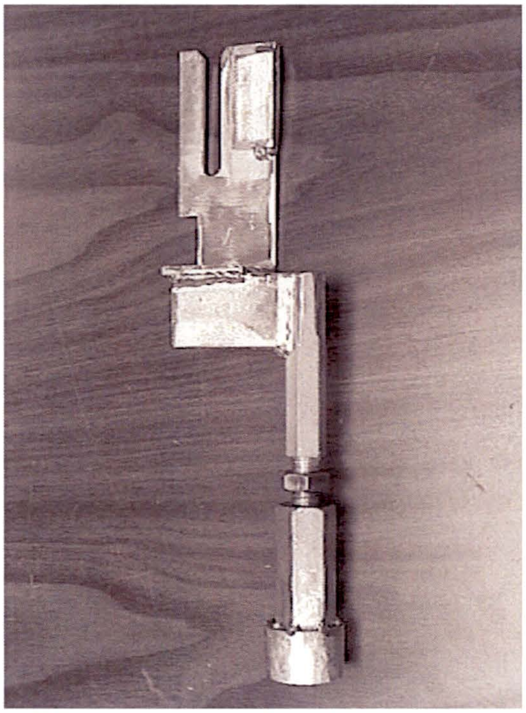
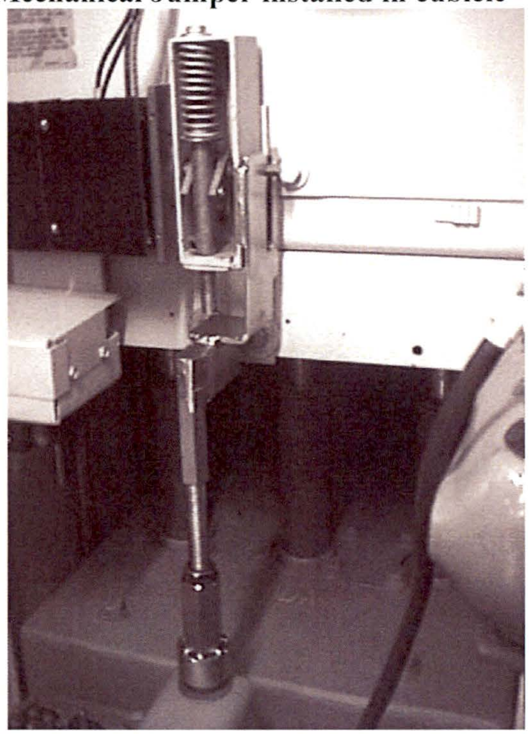


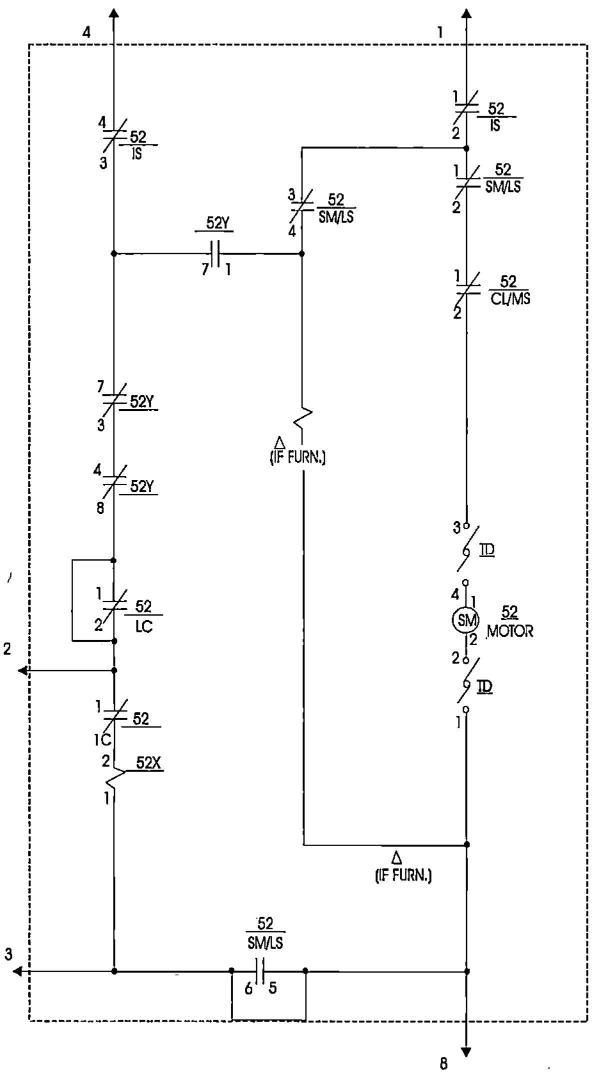
Figure 19
GE Magnablast Auxiliary Switch Mechanical Jumper

Magnablast Breaker Mechanical Jumper



Mechanical Jumper installed in cubicle





NOTES:

52 CL/MS — CLOSING LATCH MONITORING SWITCH IS CLOSED WHEN LATCH IS CAPABLE OF BLOCKING FULLY CHARGED CLOSING SPRINGS.

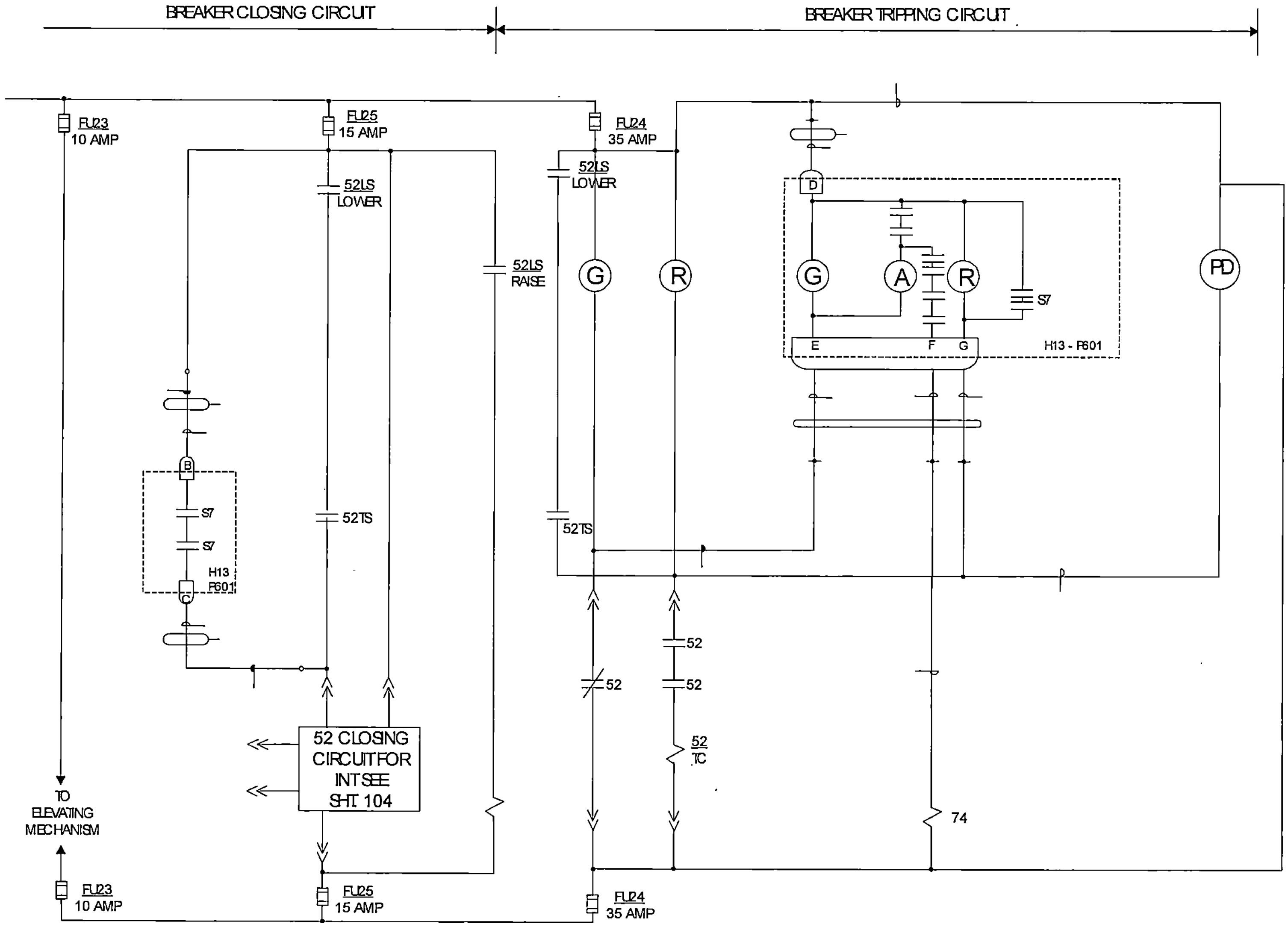
52IS — INTERLOCK SWITCH CLOSED WHEN 52 IS IN FULLY RAISED OR FULLY LOWERED POSITION.

52 SM/LS — LIMIT SWITCH FOR SPRING CHARGING MOTOR - CONTACTS (1-2) (3-4) OPEN AND CONTACT (5-6) CLOSED WHEN SPRINGS ARE FULLY CHARGED.

52X — SPRING RELEASE COIL OPERATES LATCH - WHICH RELEASES CLOSING SPRING TO CLOSE 52.

GE BREAKER SCHEME

Figure 21
GE Breaker Scheme



GE BREAKER SCHEME

Exelon Generation.

Course/Program:	ILT/NLO/LORT	Module/LP ID:	N-CL-OPS-262001
Title:	©AUXILIARY POWER	Course Code:	N-CL-OPS-262001
Author:	Steve Foley	Revision/Date:	012 / 3/15/18
Prerequisites:	None	Revision By:	Matthew Beeler
Responsible Site:	Clinton	Est. Teach Time:	8.0 hours

Qualified Nuclear Engineer Review (If applicable):	N/A	Date:	N/A
Training Supervision Review: (Print name / Signature)	R. J. Frederes /S/	Date:	06/11/18
Program Owner Approval: (Print name / Signature)	Richard Champley /S/	Date:	06/12/18

TABLE OF CONTENTS Pg. #

Exelon Generation®

OBJECTIVES

Initial: From memory, unless otherwise stated, and with 100% accuracy, in accordance with the course reference materials and procedures, the trainee shall be able to:

Continuing: Using normally available references, unless otherwise stated, and with 100% accuracy, in accordance with course reference materials and procedures, the trainee shall:

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.1	STATE the purpose(s) of the Auxiliary Power System including applicable design bases.	x	x	x	x	4
.1.2	DESCRIBE the major flowpaths for the following modes of the Auxiliary Power System operation.					
	.1 UAT/RATs to 6.9 & 4.16 KV Loads	x	x	x	x	8
	.2 ERAT/RAT 'B'/DG to 4.16 KV Loads	x	x	x	x	8
.1.3	DESCRIBE the function, operation, interlocks, trips, physical location, and power supplies of the following Auxiliary Power System components.					
	.1 Unit Auxiliary Transformers & Cooling Systems	x	x	x	x	11,12
	.2 Reserve Auxiliary Transformers & Cooling Systems	x	x	x	x	11,15, 16
	.3 Emergency Reserve Auxiliary Transformer & Cooling Systems	x	x	x	x	4,8,10, 11,20, 22
	.4 Non-segregated Phase Bus Ducts	x	x	x	x	8,9,10, 20,25
	.5 High Voltage Breakers	x	x	x	x	6,9,10, 27,33
	.6 Non-Divisional High Voltage Distribution System	x	x	x	x	9,11

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.7 Divisional High Voltage Distribution System	x	x	x	x	5,8,10, 11
	.8 480 V Substations	x	x	x	x	9
	.9 480 V Motor Control Centers	x	x	x	x	9,10, 59
.1.4	STATE the physical location and function of the following Auxiliary Power system controls, indicators, and/or sensors.					
	.1 Unit Auxiliary Transformer related controls, indicators & sensors	x	x	x	x	12,13
	.2 Reserve Auxiliary Transformer related controls, indicators & sensors	x	x	x	x	15,16,17, 19
	.3 Emergency Reserve Auxiliary Transformer related controls, indicators & sensors	x	x	x	x	20 thru 24
	.4 Non-segregated Phase Bus Duct related controls, indicators & sensors	x	x	x	x	8,25
	.5 6.9 KV Distribution System related controls, indicators & sensors	x	x	x	x	8,9,27, 38,58
	.6 4.16 KV Distribution System related controls, indicators & sensors	x	x	x	x	5,8,9,10, 27,41,45, 47,57
.1.5	Discuss the Auxiliary Power system automatic functions/interlocks including purpose, signals, set points, sensing points, when bypassed, how/when they are.					
	.1 6.9 KV Normal and Reserve Breaker Control	x	x	x	x	34,39
	.2 6.9 KV Bus Automatic Transfer	x	x	x	x	9

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.3 4.16 KV Normal and Reserve Breaker Control	x	x	x	x	34,42,48
	.4 4.16 KV Bus Automatic Transfer	x	x	x	x	9
	.5 480 VAC Bus Tie Breaker Automatic & Manual Transfer	x	x	x	x	9,40,43, 55,57,58
	.6 UAT Lockout	x	x	x	x	15
	.7 RAT Lockout	x	x	x	x	19
	.8 ERAT Lockout	x	x	x	x	24
	.9 4.16 KV and 6.9 KV Vital and Non-Vital "F" Lockout	x	x	x	x	19,20,25, 28,29,31, 32,61
	.10 4.16 KV and 6.9 KV Vital and Non-Vital "S" Lockout	x	x	x	x	19,20,25, 28,30,31, 32,60
	.11 Vital 4.16 KV Bus Degraded Voltage	x	x	x	x	49,65
	.12 Vital 4.16 KV Bus Loss of Power	x	x	x	x	49,65
	.13 480V Substations	x	x	x	x	9,10,38, 40,42,45, 54,58, 59,62
.1.6	Given an Auxiliary Power System Annunciator, DESCRIBE: a. The condition causing the annunciator b. Any automatic actions c. Any operational implications	x	x	x	x	14,18,23, 40,43,44, 50,53,56, 59
.1.7	Given the Auxiliary Power system, DESCRIBE the systems supporting and the nature of the support.	x	x	x	x	65
.1.8	Given the Auxiliary Power system, DESCRIBE the systems supported and the nature of the support.	x	x	x	x	66

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.9	DISCUSS the effect: a. A total loss or malfunction of the Auxiliary Power System has on the plant. b. A total loss or malfunction of various plant systems has on the Auxiliary Power System.	x	x	x	x	5,7,8,63
.1.10	EXPLAIN the reasons for given Auxiliary Power System operating limits and precautions.	x	x	x	x	70,73,75, 76
.1.11	EVALUATE given key Auxiliary Power System parameters, if needed DETERMINE a course of action to correct or mitigate the following abnormal condition(s):					
	.1 Placing UAT Cooling in Service	x	x	x	x	77
	.2 Removing UAT Cooling From Service	x	x	x	x	78
	.3 UAT Degraded Cooling System response	x	x	x	x	78
	.4 De-energize 4160V Bus 1A1/1B1/1C1	x	x	x	x	79
	.5 De-energize 6900V & 4160V Bus 1A/1B	x	x	x	x	80
	.6 Energize 4160V Bus 1A1/1B1/1C1	x	x	x	x	80
	.7 Energize 6900V & 4160V Bus 1A/1B	x	x	x	x	82,84
	.8 Transferring a 6.9 or 4.16 KV Bus To/From its Reserve {Main} Source	x	x	x	x	85
	.9 High Voltage 4160V Safety Buses response.	x	x	x	x	87

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.10 Low Voltage 4160V Safety Buses response.	x	x	x	x	89
	.11 Paralleling 4160V Bus Power With DG	x	x	x	x	91
	.12 DC Control Power Operations	x	x	x	x	93,94
	.13 Backfeed Using MPTs & UATs	x	x	x	x	95,97
.1.12	Given Auxiliary Power System operability status OR key parameter indications, plant conditions, and a copy of Tech Specs, DETERMINE if Tech Spec Limiting Condition for Operations have been met, and required actions if any.	x	x		x	67,68,69
.1.13	Given Auxiliary Power System key parameter indications and plant conditions, DETERMINE if the Auxiliary Power Tech Spec LCOs have been met for one hour or less LCOs.	x	x		x	68
.1.14	Given Auxiliary Power System operability status and a copy of Tech Specs, DISCUSS the bases for the Auxiliary Power System Tech Spec LCO, related safety limits and Limiting Safety System Settings.	x	x		x	67,68,69
.1.15	Given Auxiliary Power System initial conditions, predict how the system and/or plant parameters will respond to the manipulation of the following controls.					
	.1 Synchroscope Switch Controls	x	x	x	x	23,39,42, 43,47,48, 52

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.2 4.16 & 6.9 KV Switchgear Local-Remote Switch Controls	x	x	x	x	34
	.3 4.16 & 6.9 KV MCR Breaker Control Switch Controls	x	x	x	x	39,40,42, 43,48,53
.1.16	EVALUATE the following Auxiliary Power System indications/responses and DETERMINE if the indication/ response is expected and normal.					
	.1 UAT Lockout	x	x	x	x	15
	.2 RAT Lockout	x	x	x	x	19
	.3 ERAT Lockout	x	x	x	x	24
	.4 4.16 KV Bus Loss of Power	x	x	x	x	42,43,46, 49,51
	.5 Trip of DG Output Breaker	x	x	x	x	53

Evaluation Method & Passing Criteria: WRITTEN EXAMINATION WITH SCORE ≥ 80%.

References

USAR Chapter 8

CPS No. 3501.01	High Voltage Auxiliary Power System
CPS No. 3501.01C001	Generator Backfeed Checklist
CPS No. 3502.01	480 VAC Distribution
CPS No. 3502.01E001	480 VAC Electrical Distribution Lineup
CPS No. 3504.01	Main Power and Unit Auxiliary Transformer Cooling
CPS No. 3505.01	345 & 138KV Switchyard (SY)
CPS No. 3505.01E001	345 & 138KV Switchyard (SY) Electrical Lineup
CPS No. 3506.01	Diesel Generator and Support Systems (DG)
CPS 3506.01P001	Division 1 Diesel Generator Operations
CPS 3506.01P002	Division 2 Diesel Generator Operations
CPS 3506.01P003	Division 3 Diesel Generator Operations
CPS No. 4001.02	Automatic Isolation, Table 1
CPS No. 4200.01	Loss of AC Power

ARP 5007-5M (4KV BUS HIGH VOLTAGE)
ARP 5008-5L (4KV BUS LOW VOLTAGE)
ARP 5011-1E (DC FAILURE 6.9 KV BUS)
ARP 5012-1C (DC FAILURE 4.16 KV BUS 1A (1B))

SA-AA-129	Electrical Safety
SOER 82-16	Deenergized Breaker Charging Spring Motor
SOER 90-01	Ground Faults on AC Electrical Distribution System
CR 1-98-10-274	4160V BUS 1A1 De-Energized Momentarily Due To Its P. T. Fuse Cubicle Door Was Opened Inadvertently
SER 3-10	Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling (H.B. Robinson Event)
NRC IN 2012-03	DESIGN VULNERABILITY IN ELECTRIC POWER SYSTEM (BYRON EVENT)
CPS LER 2012-001-00	Loss of Secondary Containment (Transformer Trip)
CPS LER 2013-008-00	Failure of Div 1 Transformer Leads to Manual Reactor Scram
CPS LER 2017-002-01	Failure of the Division 1 Diesel Generator Ventilation Fan Load Sequence Relay Circuit During Concurrent Maintenance of RHR Division 2 Results in an Unanalyzed Condition.
ICES #311418	(HU Event) Inadvertent Trip of Condensate Booster Pump
IR 01465692	ERAT SERVERON SERVICE LIGHT ON

References (continued)

Technical Specification, 3.3.8.1	Loss of Power (LOP) Instrumentation
Technical Specification, B 3.3.8.1	Loss of Power (LOP) Instrumentation
Technical Specification, 3.8.1	AC Sources- Operating
Technical Specification, B 3.8.1	AC Sources- Operating
Technical Specification, 3.8.2	AC Sources- Shutdown
Technical Specification, B 3.8.2	AC Sources- Shutdown
Technical Specification, 3.8.9	Distribution Systems- Operating
Technical Specification, B 3.8.9	Distribution Systems- Operating
Technical Specification, 3.8.10	Distribution Systems- Shutdown
Technical Specification, B 3.8.10	Distribution Systems- Shutdown
Operational Requirements Manual, 2.5.1	Containment Penetration Conductor Overcurrent Protective Devices
E02-1AP01	Auxiliary Power Single Line Diagram
E02-1AP03	Electrical Loading Diagram
E02-1AP07	High Voltage Electrical Isometric
E02-1AP99-009, 010,15, 16, 17 038, 107, 120	Auxiliary Power schematics (various)
E02-1DG99-001	DG 1 Interface Diagram
E02-1HP99, 107	DG 3 Start Logic

SER 3-05, Weaknesses in Operator Fundamentals
SOER 10-2, Engaged, Thinking Organizations
IER L1-11-03, Weaknesses in Operator Fundamentals
INPO 15-004, Operator Fundamentals
IER 17-005, Line of Sight to the Reactor Core

NERC Standard PRC-001

Commitments: NONE

LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
0	Unknown	Unknown
1	Unknown	Unknown
2	01/09/99	Major revision - a large amount of technical content of the Training Guide has changed which requires a complete technical review of the Training Guide. Added text concerning Potential Transformers in the student text and CR 1-98-10-274.
3	05/07/02	Update to new Exelon format per TQ-AA-210-3201 R00 Lesson Plan Template (Portrait). Adjusted scope of lesson to delete MPT (transferred to Generator Lesson) and to add UAT, RAT and ERAT. Incorporated comments from System Engineer. Revised updated objectives and added material to support objectives. Resolved missing K & A links to lesson plan. Updated to reflected current electrical procedures.
3a	4/17/03	Corrected listed voltages on figure 8 and 9 to agree with associated annunciator procedure per TRACER 2003-04-0160A.
4	6/04/03	Corrected typos and minor technical errors identified during presentation. Refer to TRACER 2003-06-0023A. There are no changes to Objectives.
5	8/18/03	Deleted reference to North 345KV bus lockout caused by RAT lockout, indicated that RAT FP deluge caused by F system. (Page 15). Refer to TRACER 2003-06-0046A. There are no changes to Objectives
6	02/06/04	Incorporated Tracer 2003-08-0122A. OPEX on Quad Cities DG Auto-Start due to PT Drawer coming open.
7	3/16/05	Incorporated TRACER # 2004-05-0120A, OPEX CR210397 and 2004-09-007D, OPEX LER 2004-003-00 to this lesson in the OPEX section.
8	05/20/05	The Big Note EIN numbers on the 480V breakers/bus' on page 5 were changed to reflect proper EIN number.
9	04/17/06	Incorporated TRACER #2005-10-0052A (Operator Time Response), TRACER #2005-09-0061A (Removed reference to System Description, TRACER #2005-03-0091A (UAT Sudden Pressure Logic change).
10	07/06/06	Incorporated TRACER #2006-06-0125A: Removed Automatic Mode of Operation for Load Tap changer, changed 1st and 2nd level undervoltage values, added enhancement to page 29 and 32 for problem when buses transferred, Page 55 changed SS17 to SA-CL-129, and removed North Bus Lockout on RAT Fault from Power Point.
11	02/08/08	Incorporated TRACER #2006-08-0216A. Minor Revision.
0	03/28/08	Updated lesson plan number and objectives to align with associated KA. Incorporated a Tech Spec exercise and upgraded OPEX section.
1	02/02/09	Incorporated TRACER 2008-10-0086A (Establishment of an additional ERAT LTC setting for degraded grid voltage conditions per EC 370607).

LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
2	04/06/09	Incorporated TRACER 2008-08-0074A (Added discussion of the impact on extended loss of DC MCC 1F on ERAT Protective Relaying and ERAT Circuit Switcher B018). Incorporated TRACER 2008-07-0010A (Added content on the installation of an alternate tripping supply for the CW pump breakers per EC 0361114; added content for the auto-tripping of CD Pump A(D) during an auto-transfer from the UATs to the RAT; Removed references to the Exciter Field Breakers (which no longer exist); modified description on use of Off-Site Permissive buttons for Class 1E buses as limited to certain circumstances (consistent with ARPs); updated the UAT Cooling description to be consistent with CPS 3504.01). Incorporated TRACER 2008-12-0096A (Added discussion of how to reset common annunciator 5012-3B or common annunciator 5011-3D when affected Unit Sub trips on overcurrent).
3	07/21/09	Incorporated TRACER 2009-04-0113A (In Figure 2, corrected breaker label for 4.16 KV Bus 1A1 Main Feed to match prints (201 A1) and corrected breaker label for 6.9 KV Bus 1B Main Feed to match prints (501 B)). Updated Lesson Plan numbers to reflect latest Lesson Plan numbering scheme. Update CPS reference (SA-CL-129) to reflect standard guidance (SA-AA-129). Incorporated TRACER 2009-07-0033A (Removed 480 VAC substation 1C output breaker depicted on Bignote drawing which is not reflected in E02-1AP01-4).
4	01/22/10	Incorporated Tracer 2005-03-0092A (Incorporate C1R10 modifications into training materials) to include EC 339005 & EC 339047 (collectively supports RAT Replacement Project). Incorporated Tracers 2009-06-0025A, 2009-06-0028A & 2009-06-0026A (Installation of New Switchyard Breaker GCB 4514). Incorporated Tracer 2010-01-0082A (Review AP LP for changes due to procedure changes). Replaced wording contained in CPS procedures with references to those procedures to ensure most recent requirements are addressed. Added HU Fundamentals in 'B' column at appropriate points in the LP. Big Note is not being revised at this time.
5	05/08/12	Changed wording for Objectives 1.4.1 through 1.4.6 to be more concise (content referred to in body of Lesson Plan not changed); Changed Objective .1.15 to refer to actual controls and then referenced them in main body (content not changed); Incorporated ATI 01185341-79 (NER NC-10-028 HB Robinson)

LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
		which added HB Robinson OPEX and an in-body discussion on importance of pursuing potential loss of control power issues including a print reading exercise; Incorporated ATI 01185341-81 (which updated the AP Big Note for RAT mod); Incorporated ATI 01341299-24 (EC 380700 which modified RAT & ERAT oil and winding temperature alarm setpoints); Incorporated ATI 01341299-31 (which disabled the high voltage alarm for RAT 'B'); Disabled high voltage alarms for RATs 'A' & 'C' to match subsequent revision to CPS 5010.06 (27d); Incorporated ATI 01234003-14 to provide a better explanation of what a "Non-Segregated Phase Bus Duct" is and where it is used in the Auxiliary Power System; Incorporated applicable portions of ATI 1184934-46-4 pertaining to NERC Standard PRC-001 which requires operators to have a good understanding of auxiliary power protection schemes and limitations; Incorporated TREQ 1176976-17 (as applicable to LP) which defined a bank in terms of number of cooling fans; Deleted reference to CPS 3800.02C005 which no longer exists; Added procedural reference for 480V Substation & MCC Locations; Added major PPC screens to the instrumentation used to monitor UAT performance in Section IV.A.7; Added OPEX on Byron event.
6	06/05/12	Revised paragraphs F.6.a.3, G.5.4 and H.6.3 to clarify the operation of the bus source main and reserve feed breakers during transfer operations.
7	04/08/13	Incorporated ATI 01433216-05 (Added CPS LER 2012-001-00 as OPEX to the lesson plan). OPEX was inserted as Attachment P.
008	11/26/13	Minor Revision. Incorporated TIA 01529170-11 (Add IR 01465692 to LP). OPEX was inserted as Attachment Q. Updated LP format to latest template.
009	03/28/14	Minor Revision. Incorporated TIA 01621344-03 (Add LER 2013-008-00 (using ICES #308766 text of LER) to LP). Renamed Attachment P to Attachment P.1. OPEX was inserted as Attachment P.2.
010	12/16/14	Minor Revision: Added OPEX (ICES #311418 – (HU Event) Inadvertent Trip of Condensate Booster Pump) as Attachment P.3. Added text from referenced documents to make lesson plan self-sufficient.
011	10/24/17	Revised section IV.A.6.c.(3) with correct reset points. Incorporated LER 2017-002. Incorporated AR 01621344-92 to correctly reference SARRACS usage and add pictures of PT cubicle internals. Modified existing OPEX. Modified section IX to fully reference CPS 3501.01, 3504.01 and 3506.01. Incorporated INPO 15-004 throughout lesson plan.
012	3/15/18	Added Attachment R, LER 2017-010-00, added tie to IER 17-005. Pg. 63, D. 2 revised to address AR 04122939.

Instructional Methods:

- Lecture/discussion
- Student Exercises

Media:

- Power Point
- White board
- Trainee text

I. Introduction

To obtain a command of integrated plant operation, a detailed knowledge of the Auxiliary Power System distribution and the associated interlocks is essential. Some of the most challenging integrated plant transients involve, or are initiated from, a degradation of the Auxiliary Power System. In addition, North American Electric Reliability Corporation (NERC) Standard PRC-001 requires generation facilities (i.e. operators) to be familiar with the purpose and limitation of auxiliary power and Main Generator protection system schemes. Auxiliary power protection schemes are addressed in this lesson plan. N-CL-OPS-245002 Main Generator discusses the Main Generator protection schemes.

If the operator has not properly distributed in house loads between the high voltage buses the loss of one bus could initiate a serious plant trip. For example, it could result in a loss of both Turbine Driven Feed Pumps on low suction pressure with a simultaneous loss of Instrument Air. The loss of air would cause the MSIVs to close.

A plant event similar to this did occur at CPS. In addition to the loss of feedwater and loss of the Main Condenser as a heat sink, it also involved the loss of CRD Hydraulics as well as some plant cooling systems. This event will be reviewed during the lesson.

The operation of the Auxiliary Power System is frequently required during the preparation for, performance of, or restoration from plant maintenance activities. When these activities involve securing or restoring portions of the system a solid knowledge of the system by plant operations personnel can be pivotal in ensuring that the maintenance activity is uneventful.

The Auxiliary Power System lesson includes the Unit Auxiliary Transformers (UATs), Reserve Auxiliary Transformers (RATs) and the Emergency Reserve Auxiliary Transformer (ERAT). The in plant 6900, 4160, and 480 volt Class 1E and Non-Class 1E electrical distribution equipment is also addressed by this lesson.

Utilize INPO 15-004 throughout to emphasize:

Operator Fundamentals

- **Monitoring Plant Indications and Conditions Closely**
- **Controlling Plant Evolutions Precisely**
- **Operating the Plant with a Conservative Bias**
- **Working Effectively as a Team**
- **Having a Solid Understanding of Plant Design, Engineering Principles and Sciences**

The Switchyard lesson N-CL-OPS-262004 includes the 345 KV, 138 KV, and 12 KV distribution systems up to the primary windings of each RAT and the ERAT transformer. The Main Generator lesson N-CL-OPS-245002 includes the output of the Main Generator, the Main Power Transformers (MPTs) and up to the primary sides of the UATs.

The Static VAR Compensators (SVCs) lesson N-CL-OPS-262005 includes information on the voltage equipment used to regulate and stabilize transformer secondary voltages on RAT 'B' and the ERAT beyond that described in the Auxiliary Power Lesson Plan.

The Diesel Generator/Diesel Fuel Oil lesson plan N-CL-OPS-264000 includes the Emergency Diesel Generators and the output breaker operations. Some output breaker interlocks are addressed within the Auxiliary Power Lesson Plan.

The low voltage and instrument power and low voltage power systems derive their power from the Auxiliary Power system and are covered in lesson plans N-CL-OPS-262006 Lighting and Low Voltage Electrical Power and N-CL-OPS-262002 IP Computer Uninterruptible Power Supply (UPS).

Auxiliary Power will be presented in an 8.0 hour classroom session which includes:

- Lecture
- Exercises involving the tracing of the major flow paths on figures that will be provided
- Print reading exercises

The Objectives, to be discussed later in detail, basically include the following:

- Major component functions and physical locations.
- Describe the operation, indications, and interlocks of the high voltage electrical distribution systems.
- The causes/impact/consequences of the loss of major power sources.
- Functional relationships between this system and other plant systems.
- License and procedure requirements.

Evaluation:

- Knowledge of objectives will be as specified on page iii and evaluated as specified on page ix.

II. System Purpose

A. System Purpose — [.1.1]

1. The purpose of the Auxiliary Power (AP) AC Electrical Distribution System is to provide a redundant, diverse, and dependable power source for plant start-up, operation, and shutdown. In the event of total loss of off-site power, on-site diesel generators are provided to supply a highly reliable source of electrical power to equipment essential for a safe shutdown of the reactor.

2. The Auxiliary Power System functions to provide electrical power to the auxiliary loads required during plant operation. It also provides a highly reliable source of electrical power to those services required to shutdown the plant under certain postulated design basis events.

B. Design Basis — [.1.1]

1. Two offsite power sources provide CPS with AC electrical power to satisfy in-house power requirements. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Class 1E Buses supplying the Engineered Safety Features of the facility.

   a. Three 345 KV transmission lines tie together in the CPS Switchyard providing one source of offsite power (via three Reserve Auxiliary Transformers (RATs) to the station. Collectively, the three RATs are designed to carry station startup & shutdown loads and be a normal source of power for Class 1E loads (RAT 'B' only). — **See Figure 1.**

   b. The Clinton Route 54 Substation provides 138 KV to the station for the second source of offsite power. The 138 KV transmission line connects to the Emergency Reserve Auxiliary Transformer (ERAT) to supply power to the three safety related 4.16 KV Engineered Safety Feature (ESF) buses when the 345 KV (RAT 'B') source trips or becomes unavailable. The ERAT is designed to carry the electrical loading requirements for those loads required to support Safe Shutdown of the unit. — **[.1.3.3]** **See Figure 1.**

c. An onsite, permanently installed Static Var Compensator (SVC) is also available for connection to each offsite circuit to support required voltage for the Class 1E Buses. Operability of the offsite electrical power sources assumes the SVCs are in service and operating correctly.

2. The Auxiliary Power system is designed such that the simultaneous occurrence of a single failure, a loss of all off-site power, and a design basis event will not disable any nuclear safety function. **[.1.9]**

3. Auxiliary Power System structures, systems and components are classified as Class 1E, or Non-Class 1E. The Class 1E safety classification denotes equipment that is essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or otherwise essential in preventing significant release of radioactive material to the environment.

   a. The unit's nuclear safety related AC loads are divided into three Class 1E Divisions or Engineered Safety Feature (ESF) groups. Each Division is an independent subsystem having its own distribution equipment, controls and control power supplies. **See Figure 2.**

      1) Each Class 1E component is assigned to a Division. Class 1E components with redundant Engineered Safety Features are assigned to separate Divisions. Class 1E components of a Division are physically separated from the Class 1E components of any other Division and non-Class 1E or non-seismic Category I, or high-energy components that could cause a loss of redundancy as a result of a design basis event.

      2) Each of the three Class 1E Systems, also known as an Engineered Safety Feature (ESF) Division, has a 4.16 KV distribution bus with two sources of off site power and a dedicated Emergency Diesel Generator (DG). **[.1.3.7][.1.4.6]**

      3) There are four Class 1E 125 volt DC Distribution Divisions that support the three ESF Divisions. ESF Divisions 1 and 2 are supported by the Division 1 and 2 DC Distribution system, respectively. ESF Division 3 is supported by both the Division 3 and Division 4 DC Distribution systems.

4) An independent cable raceway system for each ESF Division is provided to meet load group cable separation requirements.

5) The Class 1E switchgear and Motor Control Center (MCC) assemblies are seismically qualified to perform their function during an Operational Basis Earthquake (OBE) and a Safe Shutdown Earthquake (SSE). They are designed to perform their required nuclear safety functions for all postulated environmental conditions in the area in which they are located.

6) Class 1E electrical equipment is color coded to assist in distinguishing which safety-related division the equipment is associated. Refer to Attachment H, Divisional Color Codes.

b. Non-Class 1E is the classification applied to all electric structures, systems and components other than Class 1E structures, systems and components. Non-Class 1E equipment is electrically isolated from the Class 1E system by an acceptable isolation device.

1) During a LOCA (High Drywell pressure and/or Low Reactor Water Level) the non-class 1E electrical loads that are connected to a given class 1E DC or 1E AC electrical bus are shunt tripped to isolate the non-vital load, with the exception of emergency lighting. This ensures that the Emergency Diesel Generators can adequately power the loads required for performing all safety functions.

2) 6.9 KV switchgear and 480 V MCCs which feed non-Class 1E loads which are located in the Containment are qualified as Class 1E.

a) Safety classification is for the protection of containment electrical penetrations. The associated non-Class 1E loads are not required to be energized under accident conditions.

b) Double breakers (in series) are used for electrical penetrations through the containment per the requirements of the Operations Requirements Manual (ORM 2.5.1). **[.1.3.5]**

Content/Skills	Activities/Notes
C. Operator Time Response Limitations	
1. During a Station Blackout the operator time response actions in controlling RPV level and pressure are assumed to occur within 10 minutes of the Station Blackout.	**[.1.9]**

III. SYSTEM FLOWPATH(S)

A. Auxiliary Power Sources	**See Figures 1, 2, 4, 5, & 6.**
1. During normal plant operations, the output of the Main Generator provides power at 22,000 volts to the primary windings of two Unit Auxiliary Transformers (UATs). This connection is made through a tap off cubical which ties into the Main Generator Isolated Phase Bus Ducts. The UATs provide power (as the <u>Main</u> source) directly to the Non-Class 1E 4.16 KV buses 1A & 1B and the 6.9 KV buses 1A & 1B, serving balance of plant loads during normal plant operation.	**[.1.2.1]**
2. Three offsite 345 KV transmission lines tie into the Switchyard providing one of two sources of offsite power via three Reserve Auxiliary Transformers (RATs) supplied from the North 345 KV bus. Each RAT is assigned loads as follows:	
a. RAT 'A' provides 6.9 KV power (as the <u>Reserve</u> source) through Non-segregated Bus Duct networking to the Non-Class 1E 6.9KV 1A & 1B buses.	**[.1.2.1][.1.4.4][.1.4.5]**
b. RAT 'B' provides 4.16KV power (as the <u>Main</u> source) through Non-segregated Bus Duct networking to the Class 1E 4.16KV 1A1, 1B1 and 1C1 buses.	**[.1.2.2][.1.3.4][.1.3.7][.1.4.4] [.1.4.6]**
c. RAT 'B' also provides 4.16KV power (as the <u>Reserve</u> source) through Non-segregated Bus Duct networking to the Non-Class 1E 4.16KV 1A bus.	**[.1.2.1][.1.3.4][.1.4.4][.1.4.6]**
d. RAT 'C' provides 4.16KV power (as the <u>Reserve</u> source) through Non-segregated Bus Duct networking to the Non-Class 1E 4.16KV 1B bus.	**[.1.2.1][.1.3.4][.1.4.4][.1.4.6]**
3. An offsite 138KV line supplies the second of two sources of off site power to the Class 1E 4.16KV 1A1, 1B1 and 1C1 buses through the Emergency Reserve Auxiliary Transformer (ERAT).	**[.1.2.2][.1.3.3][.1.3.7][.1.4.6]**
4. During a loss of offsite power three Emergency Diesel Generators, with one dedicated to each Class 1E Division, has the capability to automatically start and supply their respective divisional electrical distribution systems. There is no backup power source to the Non-Class 1E buses during a loss of offsite power from the 345KV Switchyard.	**[.1.2.2][.1.3.7][.1.4.6]** **[.1.9]**

5. The offsite 138KV line also supplies the Radwaste Auxiliary Steam Electrode Boiler through the Supplemental Cooling and Auxiliary Boiler (SCAB) Transformer and the Owner Controlled Area power needs through the CONST Transformer by way of a 12 KV distribution loop.

See Figure 3.

B. 6.9 KV & 4.16 KV Non-Vital (Non-Class 1E) Buses

[.1.3.4][.1.3.5][.1.3.6][.1.4.5] [.1.4.6]

1. The 6.9 KV & 4.16 KV Non-Vital (Non-Class 1E) Buses are powered from the secondary windings of the UATs through Non-segregated Phase Bus Ducts during normal plant operation.

See Figures 2, 4 & 5.

2. The Non-Class 1E buses are labeled 1A and 1B for both the 4.16KV and 6.9 KV sets of high voltage buses. In cases where these buses supply redundant system components, the 1A bus supplies the "A & C" loads and the 1B buses supply the "B & D" loads (depending upon the number of redundant components).

3. When the Main Generator is tripped off line the Non-Class 1E buses will automatically transfer from their respective UAT to their respective RAT (see III.A.1 & 2 above). There is no automatic transfer back to the UATs.

C. Non-Vital 480V Distribution

1. The two 6.9KV Non-Class 1E 1A and 1B buses supply eighteen 480V Unit Substations (nine from each bus) each of which contains a 6.9KV to 480 volt transformer.

See Figures 4 & 5.

[.1.3.8][.1.5.13] [.1.5.2][.1.5.4][.1.5.5]

2. Five of the nine unit substation 480 volt buses supplied from 6.9KV bus 1A have cross connecting (tie) breakers to a companion substation 480 volt bus that is normally supplied from 6.9KV bus 1B. For certain fault conditions the source of power to the buses supplied by these substations will be automatically transferred.

3. The 4.16KV Non-Class 1E buses 1A and 1B supply six 480V Unit Substations (three from each bus) each of which contains a 4.16KV to 480 volt transformer. The 480 volt buses supplied by these substations do not have cross connecting (tie) breakers.

   See Attachment L for 480 volt substation locations.

4. Each substation supplies associated Motor Control Centers (MCCs) and related loads.

[.1.3.9]

Content/Skills	Activities/Notes
D. Vital 4.16KV Buses	**[.1.3.7][.1.4.6]**
1. There are three independent 4.16KV Class 1E buses supplying the divisional vital plant loads. These buses are powered from the RAT 'B' secondary windings through Non-segregated Phase Bus Ducts during normal plant operation.	**See Figures 2 & 6.** **[.1.3.4]**
2. The Emergency Reserve Auxiliary Transformer (ERAT) provides an alternate source of power to the three 4.16KV Class 1E buses through Non-segregated Phase Bus Ducts.	**[.1.3.3][.1.3.4]**
3. The Class 1E buses are labeled 1A1, 1B1 and 1C1 supplying the Division 1, 2 and 3 loads, respectively. Operability of these buses requires availability of two offsite sources of power. RAT 'B' only counts as one source while the ERAT provides the second source. An Emergency Diesel Generator is also required for operability of each Division used to provide a highly reliable on site source of power.	
4. During an undervoltage condition, the feeder breakers will automatically operate to supply the bus with an offsite source with adequate voltage. If an offsite source is not available, the affected division's Emergency Diesel Generator will automatically start and load.	**[.1.3.5]**
E. Vital 480V Distribution	**[.1.5.13]**
1. The Division 1 and 2 4.16KV Class 1E buses each supply two 480V Unit Substations each of which contains a 4.16KV to 480 volt transformer. Each substation supplies associated Motor Control Centers (MCCs) and related loads.	**[.1.3.9]** **See Figure 6.**
2. Division 3 supplies three 480V MCCs through one common 4.16KV to 480 volt transformer.	
3. There are no cross connects between the divisional 480 volt buses.	
See Attachment L for 480 volt Substation locations.	

Summary

See E02-1AP03

What power feeds the UATs

RATs

ERAT

See Figures 2, 4, 5 & 6.

Fill in the following table:

[.1.3.1][.1.3.2][.1.3.3]

[.1.3.6][.1.3.7]

	Normal Source	Reserve Source	Emerg Source
6.9 KV non-Class 1E bus 1A			
6.9 KV non-Class 1E bus 1B			
4.16 KV non-Class 1E bus 1A			
4.16 KV non-Class 1E bus 1B			
4.16 KV Class 1E buses 1A1, 1B1 & 1C1			

IV. Components

A. Unit Auxiliary Transformers (UAT)

[.1.3.1][.1.4.1]

1. There are two, three-phase, Unit Auxiliary Transformers, 1A & 1B each of which is rated at 33.3 MVA at 55°C (37.4 MVA at 65°C). Transformer cooling is provided through a natural circulating oil flowpath which in turn transfers its heat to the outside air via cooling fans. The Main Generator output is fed to each of the UAT primaries from the Tap Off Cubical located in the Turbine Bldg. on the north end of the 762'elevation. Each UAT transforms the 22 KV through two secondary windings down to 6.9 KV and 4.16 KV which is supplied to their associated non-Class 1E 4.16 KV and 6.9 KV buses.

2. Each UAT is configured with a delta-connected primary winding and two wye-connected secondary windings labeled "X" and "Y". The "X" secondary winding supplies the associated 6.9 KV bus while the "Y" secondary winding supplies the associated 4.16 KV non-class 1E bus.

3. CPS 3504.01 MAIN POWER AND UNIT AUXILIARY TRANSFORMERS COOLING and associated valve and electrical lineups control the operating configuration of the UATs.

4. Each transformer is equipped with a mechanical self-resetting pressure relief device to protect against dangerous pressures, which may build up inside the transformer tank.

5. The UATs are located on the west side of the Turbine Building (just north of the Service Bldg). Cabling from the Tap Off Cubical runs underground across the north side of the Turbine Bldg. and then south to the UATs. The secondary output is routed to above ground cable trays to the high voltage switch gear in the Auxiliary Building.

[.1.4.1]

See E02-1AP07

6. Cooling System

[.1.3.1][.1.4.1]

   a. The UAT cooling system is divided into two stages of fans. Each stage (group) has six fans (no oil pumps).

   b. The radiator banks are bolted to an upper and lower manifold. Shutoff valves are located between the top manifold and the tank and between the bottom manifold and the tank. The fans force air across the radiators creating a differential temperature that causes oil flow between the radiator bank manifolds and the oil tank.

c. A set of control switches located on each UAT operates the associated transformer's cooling system. Each UAT has two Cooling Stage mode switches (one for each stage) with AUTO / HAND / OFF positions and one Cooler Control switch with NORM / RESERVE positions. [.1.4.1]

1) With the Cooler Control switch in NORM the Stage 1 Fans are in the Lead as winding temperature increases and the Stage 2 Fans are selected to cycle on as a Lag (reserve) to provide additional cooling, as needed. With the Cooler Control switch in RESERVE the Stage 2 Fans are the Lead fans and Stage 1 fans are the Lag fans.

2) With each stage's Cooling Stage mode switch in AUTO the Lead Stage fans will start at 60°C (140°F) winding temperature and the Lag Stage fans will start at 70°C (158°F) winding temperature. Lag Stage fans will cycle off when winding temperature reduces to less than 62.5°C (144.5°F) and Lead Stage fans will cycle off when winding temperature reduces to less than 52.5°C (126.5°F).

3) With a given Cooling Stage mode switch in HAND the associated stage's fans run continuously.

4) The cooling system is supplied with power feeds from 480 V Turbine Building MCC 1G for UAT 1A and from Turbine Building MCC 1H for UAT 1B. The cooling system is interlocked to trip off on a Fire Protection Initiation signal.

7. Instrumentation [.1.4.1]

a. MCR panel 1H13-P870

1) UAT Secondary Ammeter and Megawatt meters for feeds to 6.9 KV buses 1A and separate meters for 6.9 KV bus 1B.

2) UAT Secondary Ammeter and Megawatt meters for feeds to 4.16 KV buses 1A and separate meters for 4.16 KV bus 1B.

b. CRT screen #9 on 1H13-P680 in the MCR has the option to display Plant Process Computer (PPC) screens (formats) showing pre-determined UAT parameters. Specifically on display formats DD9A and DD9B, UAT 1A & 1B current being supplied to their respective 6.9 KV & 4.16 KV buses is shown in addition to UAT feed breaker status. Note that other PPC screens can be used to display similar information. See N-CL-OPS-700003 PLANT PROCESS COMPUTER lesson plan for further information.

DD9A represents the **Gen/Aux Electrical System Startup / Shutdown** screen.

DD9B represents the **Generator Excitation Sync / Loading** screen.

c. MCR Alarms are provided for the following conditions. Refer to Attachment B for UAT alarm details.

[.1.6]

1) Sudden Pressure
2) Trouble
3) High Temperature (winding & oil)
4) High-High Temperature (winding only)

Loss of Protective System power is monitored by Main Generator TRIP CKT FAIL alarms on 1H13-P680, Section 5008

Lockout Trip is monitored by Main Generator GEN TRIP CIRCUIT 1 OR 2 LOCKOUT TRIPPED alarms on 1H13-P680, Section 5008.

d. UAT Local Control Panel contains the following controls:

1) Cooling Mode Switches
2) Fan Control Switches
3) Heater and Cooling Control status lights

e. The following are local indications on the UAT:

1) Liquid Temperature - Normal (0 - 90°C)
2) Primary Winding Temperature - Normal (0 - 105°C)
3) Secondary Winding Temperature - Normal (0 - 105°C)
4) Oil Level Gauge - Normal (25 - 95°C)
5) Tank Pressure - Normal (-5 to +5 psig)
6) Liquid Temperature - Normal (0 - 90°C)
7) SERVERON Transformer Gas Analyzer sample status. Unit is located near the UAT.

See Attachment Q for CPS OPEX related to SEVERON blue service light status and what it means.

8. A network of relays (Sync U –Z) is used to determine if the Generator is on line. These relays only allow the UAT to be loaded when the Generator is on line. Refer to Section V, Interlocks. Also refer to Section IX, Operating Characteristics for operation with this feature defeated allowing backfeeding of the UAT during plant outages.

9. Lockouts — **[.1.5.6][.1.16.1]**

   a. Lockout Trips

      1) The Sudden Pressure –this is a redundant logic, it requires both the Tank and the Manhole Sudden Pressure Relays to actuate to cause a lockout trip.

      2) Phase Overcurrent

      3) Ground Overcurrent

   b. UAT 1A/1B Lockout relay will initiate the following automatic actions:

      1) Main Generator Lockout (and a Reactor Scram if > 33.3 %)

      2) Quick transfer of the 6.9 & 4.16 KV non-Class 1E buses to their respective RAT.

      3) Transformer FP deluge. (Sudden Pressure)

B. Reserve Auxiliary Transformers (RATs) — **[.1.3.2] [.1.4.2]**

1. There are three Reserve Auxiliary Transformers (RATs) each of which are used to transform 345 KV from the switchyard North Bus through a primary winding down to either 6.9 KV (for RAT 'A') or to 4.16 KV (for RAT 'B' and RAT 'C'). — **See E02-1AP01**

Note: With the replacement of RAT 1 per EC 339047 with three new RATs (A, B & C), RAT 'B' may still be referred to in procedures and other documentation as RAT 1 since some equipment and components remain (post modification) which once served RAT 1 but now is used for RAT 'B'. In these cases, RAT 1 is synonymous with RAT 'B'.

2. Each RAT consists of a three-phase wye-connected primary winding and a three-phase wye-connected secondary winding which is rated for 33.34 MVA at 65 °C.

3. Transformer cooling is supplied through two banks of cooling fans which are used to cool naturally circulating oil within each transformer.

4. Each RAT is equipped with a Load Tap Changer (LTC) which is used to adjust transformer output voltage as follows:

   a. The RAT 'A' & RAT 'C' LTCs are locally controlled in AUTO to help maintain transformer output voltage within a specified range even with slight variations in grid input voltage.

   b. The RAT 'B' LTC is locally controlled in MANUAL with a Load Tap Changer Setting of 5 to produce a given output voltage. To account for slight variations in grid input voltage, the output voltage is automatically controlled within a specified range using a Static VAR Compensator (SVC) which helps maintain voltage within specification as required for Safety-Related 4.16KV loads.

Having the RAT 'B' LTC in Manual and tap position 5 is required for RAT 'B' (offsite source) Operability.

5. CPS 3505.01 SWITCHYARD Electrical and Valve Lineup procedures control the electrical and mechanical configuration of each RAT.

HU Tools (for lineups) include Procedural Compliance, First Checks, STAR for Positioners and Checkers, and the requirements for verifications (I/V, C/V) per HU-AA-101. [.1.4.2]

6. RAT B is located on the west side of the Turbine Building (just north of the Service Bldg and northwest of the UATs) whereas RAT 'A' and RAT 'C' are located north of RAT 'B' and west of the Main Power Transformers (MPTs). RAT 'A' is west of RAT 'C'.

7. Cooling System

[.1.3.2][.1.4.2]

   a. The transformer cooling system for each RAT consists of 2 Stages (banks) of cooling fans which are normally setup for automatic operation. There are 4 fans per stage for RAT 'A' and 8 fans per bank for RATs 'B' & 'C'.

   b. The fans cool transformer oil (via radiator banks) which naturally circulates within the oil tank of each transformer to remove heat. An oil conservator system (RATs 'B' & 'C' only) is used to keep the transformer oil tank full of oil even with changes in oil temperature. RAT 'A' contains a Main oil tank by which a minimum oil level must be maintained.

c. One of the two Stages of cooling fans for each RAT are configured to automatically energize ON based on transformer winding temperature. The first Stage of cooling fans energize at 60C for RATs B & C and 70C for RAT A. The second Stage of fans will also energize ON if transformer winding temperature reaches 70C for RATs B & C and 80C for RAT A.

d. See CPS 3505.01 345 & 138 KV Switchyard Section 8.3.4 for further information.

e. The cooling fans for each RAT are normally powered from TB MCC 1G (1AP54E) located in the Turbine Building 737'. The alternate fan supply source for each RAT is from the 12KV switchyard via Circuit 305 and a 1500 KVA transformer located South of RAT 'A'. The alternate source of power would be automatically selected via an automatic bus transfer switch upon a loss of the normal supply.

[.1.4.2]

8. Instrumentation

a. MCR panel 1H13-P870

1) RAT A,(B),[C] Primary Current meters.

2) Bus 1RT6 Feeder To 6900 V bus 1A (1B) Current meters.

3) Bus 1RT6 Feeder To 6900 V bus 1A (1B) Watt meters.

4) 6900 V Bus 1A (1B) Voltage meters.

5) Bus 1RT4 Feeder To 4160 V bus 1A (1B) Current meters.

6) Bus 1RT4 Feeder To 4160 V bus 1A (1B) Watt meters.

7) 4160 V Bus 1A (1B) Voltage meters.

b. MCR panel 1H13-P877

1) Bus 1RT4 Feeder To 4160 V Bus 1A1 Current meter.

2) 4160 V Bus 1A1 Voltage meter.

3) Bus 1RT4 Feeder To 4160 V Bus 1B1 Current meter.

4) 4160 V Bus 1B1 Voltage meter.

c. MCR panel 1H13-P601

1) Bus 1RT4 Feeder To 4160 V Bus 1C1 KW meter.

2) Bus 1RT4 Feeder To 4160 V Bus 1C1 Current meter.

3) 4160 V Bus 1C1 Voltage meter.

d. SERVERON Transformer Gas Analyzer sample status. Unit is located near the associated RAT.

See Attachment Q for CPS OPEX related to SEVERON blue service light status and what it means.

e. MCR Alarms are provided for several abnormal RAT conditions. Refer to Attachments A through G (as applicable) for alarm details.

[.1.6]

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

f. There are two RAT relay panels located in the Relay Room at 781' elevation of the Control Building: **[.1.4.2]**

1) Relay panel PL90J is used to house key protection and lockout relays for RAT 'B' in addition to certain protective relays for RATs 'A' & 'C'. The front of the panel allows the manual reset of seven different lockout relays when directed by procedure. Each manual reset switch has a White (tripped) and Blue (reset) light indication associated with it.

2) Relay panel PL90JA is used to house key protection and lockout relays for RATs 'A' & 'C'. The relays consist of advanced SEL-501 relays used for phase and neutral overcurrent protection and SEL-587 relays used for differential current protection. The front of the panel allows the manual reset of four different lockout relays when directed by procedure. Each manual reset switch has a White (lockout relay tripped and energized) and Blue (lockout relay reset and deenergized) light indication associated with it. **[.1.5.9][.1.5.10]**

g. Local controls and indications available at each RAT include: **[.1.4.2]**

1) Cooling Fan and Heater controls.

2) Local alarm annunciators (which provide input into common RAT annunciators in the MCR).

3) Load Tap Changer (LTC) controls (located within the LTC Control Panel).

4) Indications of liquid oil temperatures and levels and transformer winding temperatures.

9. RAT Lockouts **[.1.5.7][.1.16.2]**

a. <u>Fault Pressure Trip and Lockout</u> relays detect a pressure rise (due to an internal transformer fault) designed to trip and lockout affected RAT before significant internal damage occurs.

1) RAT 'A' produces a Fault Pressure Trip at 4 psig using 1 of 2 taken twice trip logic.

2) RATs 'B' & 'C' produce a Fault Pressure Trip at 4 psig using 2 of 2 trip logic.

b. Differential Overcurrent relays constantly measure the amplitude and phase relationship of each of the transformer phases to calculate a current difference used to detect a phase imbalance resulting from a possible fault. These relays when tripped will lockout the affected RAT (using protection system F). [.1.5.9]

c. Neutral Overcurrent relays monitor for potential faults which would cause a phase imbalance to ground resulting in a rise in neutral-to-ground current flow. These relays when tripped will lockout the affected RAT (using protection system S). [.1.5.10]

d. Instantaneous / Timed Overcurrent relays monitor for overcurrent conditions and are designed such that a more severe fault condition (higher fault current sensed) results in a faster response time of the relay device when tripping. These relays when tripped will lockout the affected RAT (using protection system S). [.1.5.10]

e. Each RAT uses a combination of differential overcurrent, neutral overcurrent, and instantaneous / timed overcurrent relays to protect both the transformer primary & secondary windings, attached bus work, and associated loads from potential damage.

f. Automatic Actions

1) RAT circuit switcher 4538 opens and locks out (F or S protection system).

2) Feeder breakers supplied by the Non-segregated Phase Bus Ducts connected to the affected RAT will open and lock out (F or S protection system). [.1.3.4]

3) RAT 'B' SVC trip (F or S protection system).

4) RAT 'B' Fire Protection Deluge system automatically initiates (F protection system only).

C. Emergency Reserve Auxiliary Transformer (ERAT) [.1.3.3][.1.4.3]

1. The Emergency Reserve Auxiliary Transformer is a single, three-phase transformer rated at 18/24/30 MVA @65C OA/FA/FA. It transforms the 138 KV line input into 4.16 KV output to supply a redundant source of off-site emergency power to the Class 1E buses through cable connections to Non-segregated Phase Bus Duct networking. [.1.3.4]

2. The ERAT has one (1) wye-connected primary and one (1) wye-connected secondary.

[.1.4.3]

3. The ERAT is located outdoors west of the Service Bldg and north of the Makeup Water Pump House.

4. Attached to the ERAT, in a separate enclosure with its own insulating oil volume, is the Load Tap Changer. The LTC regulates voltage to the 4.16 KV buses to accommodate voltage swings in the 138 KV system by increasing or decreasing the number of windings in service. The LTC will work in conjunction with or independent of the ERAT Static Var Compensator (SVC). There are four modes of operation:

Having the ERAT LTC in Manual and tap position 2L is required for ERAT (offsite source) Operability.

   a. Automatic SVC Mode

      1) The ERAT SVC automatically controls the tap settings.

   b. Automatic Voltage Regulator Mode

      1) The ERAT voltage regulator automatically controls the tap settings.

   c. Manual Mode With Tap Motor

      1) Tap settings are changed with the tap motor Raise/Lower selector switch.

   d. Manual Mode With Hand Crank

      1) Tap settings are changed with a hand crank.

NOTE:
Per the plant operating procedure the LTC can only be run in manual mode of operation (normally using the tap motor).

5. With the grid experiencing a degraded voltage condition such that the 138 KV line voltage feeding the ERAT has lowered to a given level, the ERAT LTC may be manually adjusted such as to raise ERAT output voltage. This action helps to mitigate the degraded grid voltage condition with the ERAT supplying divisional Class-1E bus (1A1, 1B1, 1C1) equipment while maintaining 138 KV offsite source operability.

HU Tools (for LTC adjustments) include Procedural Compliance, using two 138KV Switchyard qualified operators, Peer Checks, STAR, and proper 3-Part (and continuous) communications when executing the ERAT LTC Switching Order per CPS 3505.01C002.

See EC 370607

Revision 3 to the 19-AK-13 calculation identifies an alternative tap setting for the ERAT LTC under low grid voltage conditions.

NOTE:

Although Revision 3 to the 19-AK-13 calculation identified an alternative tap setting, this new tap setting will not be used until implemented within approved procedures.

6. Cooling System

   [.1.3.3][.1.4.3]

   a. The ERAT is cooled by two Groups (banks) of forced air coolers. Group 1 has four fans and Group 2 has four fans. There are no oil pumps.

   b. A local Cooler Transfer switch selects one of two separate control circuits for controlling which group of fans will be the lead Group and which is the backup Group. In Position 1, Group 1 is the Lead and Group 2 is the Backup. In Position 2 it is reversed.

      1) Lead Group comes on at 70 C.

      2) Backup Group comes on at 75 C.

   c. AUTO/OFF/MAN switch for each Cooler Group when placed in Manual will cause the associated Group to run continuously. In OFF the Group is secured.

   d. See CPS 3505.01 345 & 138 KV Switchyard Section 8.3.4 for further information.

7. CPS 3505.01 SWITCHYARD Electrical and Valve Lineup procedures control the electrical and mechanical operating configuration of the ERAT.

   HU Tools (for lineups) include Procedural Compliance, First Checks, STAR for Positioners and Checkers, and the requirements for verifications (I/V, C/V) per HU-AA-101.

8. Auxiliary power (480V) for the ERAT is supplied from a 75KV/138KV transformer in the ERAT fenced area. Backup 480Vpower is provided from a 12KV source.

9. Major Instrumentation

   a. MCR panel P870 Primary Side Ammeter (0-200 amps)

   b. MCR panel 1H13-P877

      1) 1ET4 current to Bus 1A1

2) 1ET4 current to Bus 1B1

c. MCR panel 1H13-P601

1) 1ET4 current and kW to 1C1

d. MCR Alarms are provided for the following conditions. Refer to Attachments A through G (as applicable). **[.1.6]**

1) DC Failure Protective System S & F
2) Lockout Trip
3) Sudden Pressure/Fault Pressure
4) Trouble
5) High Temperature (Xfmr winding & oil, LTC oil)

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

e. The following will cause a MCR panel P870 ERAT Trouble alarm: **[.1.6]**

1) ERAT Voltage Reg. Transferred to backup power
2) Intertaire Pressure System (Hi/Lo Pressure)
3) ERAT 480V auxiliary power transfer to 12KV source.
4) Loss power to Cooling Fan controls
5) Low Oil Level
6) Mechanical Relief actuated.

f. A loss of voltage from the ERAT will alarm 5060-1D and 5061-1D, NOT AVAILABLE 4160v BUS BREAKER. The undervoltage condition can be confirmed by using the synchroscope controls. **[.1.6]** **[.1.15.1]**

g. The ERAT relay panel (1PL90J) is located in the Aux. Electrical Equipment Room 781' elevation of the Control Building. There are 4 lockout relays mounted on the Panel with White (tripped) and Blue (reset) light indication. **[.1.4.3]**

h. ERAT Local Control include the following:

1) Load Tap Changer Controls

a) Test / Operate switch

b) Local Control / Remote Control switch

c) Manual Control / Automatic Control switch

d) Manual Raise / Manual Lower switch

e) Inertaire gas system controls

2) Cabinet Heater On-Off handswitch

3) Alarm Test/Reset - Off toggle switches

4) Fan Selector and Control switches

5) Thermal device current test knife switch

6) Auxiliary power breaker

i. The following are local indications on the ERAT:

1) Oil Temperature

2) Liquid Oil Level (Referenced to 25°C)

3) Tap Changer Setting (LTC Cabinet)

4) Inertaire System nitrogen cylinder gauge

5) SERVERON Transformer Gas Analyzer sample status. Unit is located near the ERAT.

See Attachment Q for CPS OPEX related to SEVERON blue service light status and what it means.

6) ERAT Tank Pressure

10. The ERAT relay panel (0PL90J) is located at 781' Control Building.

11. ERAT Lockouts

[.1.4.3][.1.5.8][.1.16.3]

a. Sudden/Fault Pressure Lockout relay detects a rapid pressure rise within the transformer tank as a result of internal arcing. This relay will not be activated by normal pressure variations due to transformer temperature changes.

Content/Skills	Activities/Notes
b. Internal fault in the transformer.	
1) Transformer Differential Current	**[.1.5.9]**
2) 138 KV Winding Neutral Overcurrent	**[.1.5.10]**
3) 138 KV Winding Overcurrent	**[.1.5.10]**
4) 4 KV Winding Neutral Overcurrent	**[.1.5.10]**
c. Automatic Actions	
1) ERAT circuit switcher B018 opens and locks out.	
2) Lockout ET or RT Non-segregated Phase Bus Ducts connected to the ERAT.	**[.1.3.4]**
3) Feeder breakers supplied by the Non-segregated Phase Bus Ducts connected to the ERAT (1ET4) open and lock out.	**[.1.3.4]**
4) ERAT Fire Protection Deluge.	
D. Non-Segregated Phase Buses	**[.1.3.4]**
1. Non-segregated Phase Bus Duct networking is designed for use on power distribution circuits whose importance requires greater reliability than typical power cables provide. Non-segregated Phase Bus Ducts are therefore used as an electrical conduit between the major Auxiliary Power System sources and their respective buses.	
2. Non-segregated Phase Bus Ducting consists of an assembly of bus conductors with associated connections, joints, and insulating supports confined within a metal enclosure without interphase barriers. The conductors are adequately separated and insulated from each other to ensure reliability.	
3. The Non-Segregated Phase Bus Duct provides for connecting the ERAT and each RAT to their respective buses. The connection is made through a network of disconnects that are interlocked using Kirk Key Interlocks. The UATs are connected directly to the non-Class 1E 6.9 KV and 4.16 KV buses through the respective bus Main supply breakers.	**[.1.4.4]**

4. The disconnect switches will allow alignment of either the ERAT or RAT 'B' to the ET4 Bus. Initially the disconnect switches were installed to allow cross connecting Auxiliary Power between Unit 1 and 2 Emergency and Reserve Auxiliary Transformers.

5. The Kirk Key Interlocks are designed to prevent paralleling two different sources through the Non-segregated Phase Bus Ducts. One switch must be opened before the key can be removed and used to unlock another disconnect, which can then be closed on the alternate source. The disconnects are not to be operated under load.

HU Tools (for manipulating disconnects) include First Checks and STAR. A Questioning Attitude (and Verifying Assumptions) is very important in ensuring disconnects are not operated under load.

6. To prevent continuous transformer paralleling, the following "Kirk Key" interlock arrangements are provided such that only one out of two in each group of the following disconnect switches may be closed at any one time.

   a. RT14, and RT4

   b. RT16, and RT6

   c. ET14, and ET4

See E02-1AP07
See E02-1AP03

7. During normal operation RT14, RTC14, RT16 and ET4 are closed. The other disconnects are left open. Refer to Attachment I for locations.

8. Major Instrumentation

   a. For each feed to a 4.16 KV or 6.9 KV bus, indication of current and wattage is provided in the MCR Panels P870, P877, P601 and P827. Refer to Attachment J. **[.1.4.5][.1.4.6]**

   b. There are individual Red (closed) and Green (open) indicating lights on MCR Panel P870 for bus disconnect switches: RT16, RT6, RT14, RT4 & RTC14.

9. Protective Relaying

   a. The Non-segregated Phase Buses are protected by a set of lockout relays for a fault sensed either on the bus section or on the transformer source feeding the Non-segregated Bus section. Actuation of the associated transformer or bus section relays will trip open and block closure of any feeder breakers, which are routing power from the bus section to the high voltage Auxiliary Power switchgear. **[.1.3.5]**

   b. The Non-segregated Phase Bus protection has two sub-systems, the "F" and "S" systems. The "F" system is typically the first to actuate on a fault and the "S" is a backup. Transfers that occur due to "F" System operation should not cause bus loads to shed due to undervoltage, however, transfers initiated from the "S" System operation will most likely result in bus loads being shed.

   c. The Non-segregated Phase Bus disconnects, when closed, establish the lockout logic by grouping transformer and bus protective relays into relay networks. This causes the bus relays and associated transformer relays within a network to work in parallel, cross tripping to provide robust fault protection. This configuration results in a transformer or bus fault causing:

      1) Lockout trip of the associated transformer.

      2) All of the high voltage feeder breakers connected to the network to be tripped open and locked out. **[.1.3.5]**

d. The F and S Systems are formed up into two separate and independent relay networks. The disconnect switches make up the proper logic ties within the F System and separately within the S System.

e. RAT 'A' protection system logic based on the normal disconnect electrical lineup configuration enables the following "F" and "S" System logic protection:

1) RAT 'A' "F" System Logic

[.1.5.9]

a) RAT 'A' 87/150BFF-RTA Differential Relay will trip the 86F-RTA Lockout Relay, 586F-B1 Lockout Relay, and 186BF-4538 Lockout Relay. This directly actuates a lockout of RAT 'A' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and 6.9 KV bus Reserve feeds 552-521A & B.

NOTE: Trip & Lockout of RAT Circuit Switcher 4538 is directly actuated via the main RAT lockout (86) device for the affected RAT.

b) RAT 'A' 587-B1 Differential 6.9 KV Bus Relay on the RT-6 Non-segregated Phase Bus will trip the 86F-RTA Lockout Relay and 586F-B1 Lockout Relay. This directly actuates a lockout of RAT 'A' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and 6.9 KV bus Reserve feeds 552-521A & B.

NOTE: Tripping of the 186BF-4538 Lockout Relay occurs after RAT Circuit Switcher 4538 fails to open on fault. Annunciator 5010-2A comes in as a result.

c) RAT 'A' 150H-RTA Overcurrent Relay will trip the 186BF-4538 Lockout Relay causing a lockout of the 186BF-4538 RAT Circuit Switcher.

2) RAT 'A' "S" System Logic

[.1.5.10]

a) RAT 'A' 151N/551N-RTA Neutral Overcurrent Relay will trip the 86S-RTA Lockout Relay and 586S-B1 Lockout Relay. This directly actuates a lockout of RAT 'A' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and 6.9 KV bus Reserve feeds 552-521A & B.

b) RAT 'A' 150/151/150BFS-RTA Overcurrent Relay will trip the 86S-RTA Lockout Relay, 586S-B1 Lockout Relay, and the 186BF-4538 Lockout Relay. This directly actuates a lockout of RAT 'A' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and 6.9 KV bus Reserve feeds 552-521A & B.

f. RAT 'B' protection system logic based on the normal disconnect electrical lineup configuration enables the following "F" and "S" System logic protection:

1) RAT 'B' "F" System Logic

[.1.5.9]

a) RAT 'B' 87-RT1 Differential Relay will trip the 86F-RT1 Lockout Relay and the 286F-B1 Lockout Relay. This directly actuates a Lockout of RAT 'B' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher, 4.16 KV Class-1E bus Main feeds 252-201A1, 252-201B1 and 252-201C1 and non-Class 1E 4.16 KV bus 1A Reserve feed 252-221A.

NOTE: Trip & Lockout of RAT Circuit Switcher 4538 is directly actuated via the main RAT lockout (86) device for the affected RAT.

b) RAT 'B' 287-B1 Differential 4.16 KV Bus Relay will trip the 86F-RT1 Lockout Relay and the 286F-B1 Lockout Relay. This directly actuates a lockout of RAT 'B' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher, 4.16 KV Class-1E bus Main feeds 252-201A1, 252-201B1 and 252-201C1 and non-Class 1E 4.16 KV bus 1A Reserve feed 252-221A.

c) RAT 'B' 150BF-RT1 Overcurrent Relay will trip 162BF-4538 Time Delay Relay (TD-5), and 186BF-4538 Lockout Relay causing a lockout of the 186BF-4538 RAT Circuit Switcher.

NOTE: Tripping of the 186BF-4538 Lockout Relay occurs after RAT Circuit Switcher 4538 fails to open on fault. Annunciator 5010-2A comes in as a result.

d) RAT 'B' 150H-RT1 Overcurrent Relay will trip the 186BF-4538 Lockout Relay causing a lockout of the 186BF-4538 RAT Circuit Switcher.

e) Any RAT 'B' "F" System lockout will result in automatic FP deluging of the RAT 'B' transformer.

f) Any RAT 'B' "F" System lockout will result in automatic trip of the RAT 'B' Static Var Compensator (SVC).

2) RAT 'B' "S" System Logic

[.1.5.10]

a) RAT 'B' 151N-RT1 Neutral Overcurrent Relay will trip the 86S-RT1 Lockout Relay and the 286S-B1 Lockout Relay. This directly actuates a lockout of RAT 'B' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher, 4.16 KV Class-1E bus Main feeds 252-201A1, 252-201B1 and 252-201C1 and non-Class 1E 4.16 KV bus 1A Reserve feed 252-221A.

b) RAT 'B' 251N-RT1 4.16 KV Neutral Overcurrent Relay will trip the 86S-RT1 Lockout Relay and the 286S-B1 Lockout Relay. This directly actuates a lockout of RAT 'B' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher, 4.16 KV Class-1E bus Main feeds 252-201A1, 252-201B1 and 252-201C1 and non-Class 1E 4.16 KV bus 1A Reserve feed 252-221A.

c) RAT 'B' 151/150-RT1 345KV Time Overcurrent Relay and 151/150-RT1 IIT Relay will trip the 86S-RT1 Lockout Relay and the 286S-B1 Lockout Relay. This directly actuates a lockout of RAT 'B' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher, 4.16 KV Class-1E bus Main feeds 252-201A1, 252-201B1 and 252-201C1 and non-Class 1E 4.16 KV bus 1A Reserve feed 252-221A.

d) Any RAT 'B' "S" System lockout will result in automatic trip of the RAT 'B' Static Var Compensator (SVC).

g. RAT 'C' protection system logic based on the normal disconnect electrical lineup configuration enables the following "F" and "S" System logic protection:

1) RAT 'C' "F" System Logic

[.1.5.9]

a) RAT 'C' 87/150BFF-RTC Differential Relay will trip the 86F-RTC Lockout Relay and 186BF-4538 Lockout Relay. This directly actuates a lockout of RAT 'C' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and non-Class 1E 4.16 KV bus 1B Reserve feed 252-221B.

NOTE: Trip & Lockout of RAT Circuit Switcher 4538 is directly actuated via the main RAT lockout (86) device for the affected RAT.

b) RAT 'C' 150H-RTC Overcurrent Relay will trip the 186BF-4538 Lockout Relay causing a lockout of the 186BF-4538 RAT Circuit Switcher.

NOTE: Tripping of the 186BF-4538 Lockout Relay occurs after RAT Circuit Switcher 4538 fails to open on fault. Annunciator 5010-2A comes in as a result.

2) RAT 'C' "S" System Logic

[.1.5.10]

a) RAT 'C' 151N/251N-RTC Neutral Overcurrent Relay will trip the 86S-RTC Lockout Relay. This directly actuates a lockout of RAT 'C' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and non-Class 1E 4.16 KV bus 1B Reserve feed 252-221B.

b) RAT 'C' 150/151/150BFS-RTC Overcurrent Relay will trip the 86S-RTC Lockout Relay and the 186BF-4538 Lockout Relay. This directly actuates a lockout of RAT 'C' which includes the trip & lockout of 186BF-4538 RAT Circuit Switcher and non-Class 1E 4.16 KV bus 1B Reserve feed 252-221B.

h. ERAT "F" System logic based on the normal disconnect electrical lineup configuration enables the following: [.1.5.9]

1) ERAT Transformer Differential Current relay (87 ET device) actuates the **86F-ET** "F" Lockout. This relay directly actuates a Lockout of the ERAT and actuates Fire Protection.

2) Differential Current relay (287-BE) on the ET-4 Non-segregated Phase Bus actuates the **286F-BE** Bus Lockout relay. This relay directly actuates a Lockout trip of 252-221A1, 1B1 and 1C1.

3) Normally, Disconnect ET-4 is closed. This results in relays **86F-ET** and **286F-BE** to be connected in parallel. If the inputs to either of these relays actuate, both are energized resulting in the Lockout actuation associated with both relays.

i. The major sections of the ERAT "S" System logic that are normally connected through the disconnects are as follows: [.1.5.10]

1) ERAT Transformer Neutral and Winding Overcurrent relays (350, 351, 351N, 251N) monitor the primary and secondary windings. They can each actuate the 86S-ET "S" Lockout. Fault Pressure (63FP) also actuates Lockout **86S-ET**. Lockout relay **86S-ET** directly actuates a Lockout of the ERAT and actuates Fire Protection.

2) There are no relays that directly monitor faults on the ET-4 Non-segregated Phase Bus to actuate the "S" System. However, **286S-BE** Bus Lockout relay is actuated by the same inputs as **86S-ET** when ET-4 is closed. The **286S-BE** relay directly actuates a Lockout trip of 252-221A1, 1B1 and 1C1.

3) Normally, Disconnect ET-4 is closed. This results in relays **86S-ET** and **286S-BE** to be connected in parallel. If the inputs to either of these relays actuate, both are energized resulting in the Lockout actuation associated with both relays.

j. Refer to Attachments A through G for major annunciators associated with the Auxiliary Power system.

E. High Voltage Breakers (General)

[.1.3.5]

1. The circuit breakers used in the 6.9 KV and 4.16 KV Switchgear are air magnetic or vacuum, three pole, single throw, of the stored energy type, with electrically charged spring, and operated from a 125 VDC control source. The breakers have anti-pumping features to prevent damage to the load and/or breaker.

2. General physical locations of HV circuit breakers used in the 6.9 KV and 4.16 KV Switchgear are described with the respective Switchgear in the next section.

3. The 6.9 KV and 4.16 KV breakers are of the "draw out" type to allow racking out the breaker from the switchgear.

HU Tools (for breaker ops) include Procedural Compliance, First Checks, Peer Checks and STAR before and during breaker operation.

   a. For all 4.16 KV and 6.9 KV switchgear, a Safety Remote Breaker Racking System (SARRACS) is used to safely position the Magna-Blast type breakers from a remote location to ensure personnel safety.

   b. This places the breaker in the racked-out / racked-down / disconnected position. The breaker can subsequently be drawn-out / removed per maintenance procedures.

4. The doors of the switchgear are equipped with bolts/latches to securely tighten them.

- **Having a Solid Understanding of Plant Design, Engineering Principles and Sciences**

   a. For all 4.16 KV switchgear except Division 3 4.16 KV 1C1 switchgear, the breaker front cubicle door is shut and bolts torqued per the torque values posted on the cubicle door.

   b. For all 6.9 KV switchgear, the breaker front cubicle door is shut and latches engaged.

   c. For Division 3 4.16 KV 1C1 switchgear, the breaker cubicle door is shut and cubicle door latches engaged.

   d. If bolts are untorqued or latches disengaged (as applicable) on an above switchgear breaker door during operation / on-line maintenance / PMT / surveillance, etc, this places the breaker in a 'Seismically Unanalyzed Configuration' on OPERABLE switchgear. The switchgear need not be declared INOPERABLE, provided the time in this configuration is limited to 48 hours per occurrence, and appropriate personnel remain at the breaker cubicle (when the cubicle door is open) in order to return the breaker cubicle to a 'Seismically Analyzed Configuration' when directed.

An exception to the above requirement is for non-safety related Division 1 & 2 switchgear located in Seismic Category 1 areas which do not perform any safety functions.

e. NSED-Equipment Qualification Impact Assessment was performed to determine the operability of this switchgear given one of the bolts either being loose or stripped. The results determined that the operability was not impacted with just one of the bolts loose or stripped.

5. All the 4.16 KV and 6.9 KV switchgear feeder breakers are equipped with timed overcurrent trip relays for ∅A and ∅C and a ground fault relay. The main feeder breakers are equipped with bus under voltage relay ∅A to B and ∅B to C, and bus under voltage auxiliary relays.

6. Controls and Indications

[.1.5.1][.1.5.3]

a. With exception of Division 3 4.16 KV 1C1 switchgear, the breakers on the 4.16 KV & 6.9 KV switchgear have a Local-Remote selector switch, which allows transfer of the breaker control to the MCR when in "Remote". In the "Local" position, the breaker can be cycled open and closed while it is racked in the "Test" position only.

[.1.15.2]

b. The Division 3 4.16 KV 1C1 switchgear (GE Magna-Blast) breakers do not use a Local-Remote switch but instead rely on procedurally positioning the breaker within its enclosure (i.e. racked-out / racked–down / disconnected position and then withdrawn ~2 ¼ inches) to allow local testing of the breaker. In addition, for surveillance testing requiring automatic (remote) operation of the breaker in the Test Position, a mechanical jumper is used to allow the breaker to actuate the breaker auxiliary switches while in its Test Position.

c. All the breakers for motors on the 4.16 KV and 6.9 KV switchgear have an elapsed time meter that can be used to determine the run time on the associated motor.

d. Most of the breakers on the 4.16 KV and 6.9 KV switchgear that are equipped with Lock Out Relays have White (Tripped) and Blue (Reset) indicating lights.

e. All 4.16 KV and 6.9 KV switchgear breakers are equipped with Green (Open) and Red (Closed) indicating lights which are powered from breaker DC control power (via supply and return control power fuses).

Figure 9

1) The Green (Open) indication "looks" directly at the position of the breaker via the breaker's auxiliary 52/b contact. When the breaker is open, the 52/b contact is shut allowing for the open indication.

2) The Red (Closed) indication "looks" directly at the position of the breaker via a pair of the breaker's auxiliary 52/a contacts (in series with the breaker trip coil (TC)). When the breaker is shut, the 52/a contacts are shut allowing for the closed indication.

<u>**IMPORTANT**</u>: The breaker Red (Closed) indicating lights provide more information to the operator than just breaker closed indication. The Red (Closed) lights being lit also informs the operator that the breaker trip coil (which is electrically in series with the Red lights) is electrically intact standing by to trip the breaker on an electrical fault on its associated bus.

A major contributing factor which increased the severity of the H.B. Robinson event (Appendix N) was the inability of a key breaker to trip open on a bus overcurrent condition due to one of its control power fuses becoming dislodged from its fuse holder via mechanical shock. This condition remained unidentified by the station. See Appendix N for more information.

Control power fuses which are not installed correctly, have blown, or otherwise just lose physical contact with the circuit they are designed to power and protect, will cause both breaker indications (both Open and Closed) to either extinguish or not light depending on the position of the breaker.

For a breaker which is already closed under this condition, the ability of the breaker to automatically protect its bus (by tripping open via its trip coil) is lost since power to the breaker trip coil would be unavailable from DC control power (i.e. the trip coil must energize to trip the breaker).

Using Figure 9, trace the control power flowpath through a typical 4.16 or 6.9 KV breaker in terms of breaker status (open or closed) indication and the relationship of the breaker's trip coil with the breaker closed indication. PROVE how a defective breaker control power fuse related to closed breaker position indication affects the ability of the breaker to automatically trip.

Print Reading Exercise:

Using Figure 9, PROVE how a defective breaker control power fuse related to breaker closed position indication affects the ability of a breaker to automatically trip.

For other than a defective control power fuse, what else can cause a loss of Red (Closed) indications? What is the potential impact on the plant?

As an operator, it is important to realize (i.e. on rounds, casual observation, etc.) what a loss of breaker indication REALLY means and the potential impact on personnel & plant safety.

Refer to Appendix N (H.B. Robinson event) to learn more about the potential consequence of ignoring what APPEARS to be a MINOR equipment issue.

Think about the Fundamentals to be applied here at CPS which can help mitigate or prevent such an event.

7. All breaker activities performed on operable switchgear shall be evaluated for switchgear operability, and seismic qualification per CPS 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program. This includes, but is not limited to, opening the cubicle door and racking operations.

   HU Tools (for breaker ops) include Procedural Compliance, First Checks, Peer Checks and STAR before and during breaker operation.

   a. Prior to racking out or in a 4160V or 6900V breaker, remove the control power fuses.

b. When verifying breakers racked in, verify that the charging spring motor circuit is energized (on breakers that are so equipped).

c. Each time a 4160V 1C1 (1E22-S004) Magna-Blast Breaker is racked-in, the Plunger/Aux Switch Rod Contact Gap measurements shall be verified SAT per CPS 3515.01, Operation Of 6900/4160/480V Circuit Breakers.

8. Breaker Identification

a. Physical identification of safety-related equipment involves two methods of identification, color code and segregation code. The codes are used to distinguish between the different Class 1E Divisions and non-Class 1E components.

b. In addition to the color codes described in Attachment I, AC breakers are designated as follows: X-52-X-X-XX (52 = AC Circuit Breaker) Refer to Attachment K, Auxiliary Power Breaker Codes.

HU Tools (for breaker identification) include a Questioning Attitude (and Verifying Assumptions) if something does not "look right" (i.e. same component with multiple IDs or two components with the same ID).

Given the following Breaker Numbers, identify the breaker.

- 552-501A
- 552-521B
- 452-401A

Given the following breaker description identify the breaker number.

- 4.16 KV AC Circuit Breaker, 4.16 KV Bus Main Feed Breaker, Bus 1A1
- 480 V AC Circuit Breaker, 480 V Bus, Tie Breaker, Bus 1L & 1M

F. 6900 Volt Switchgear

1. The 6.9 KV System consists of 2 non-divisional buses, 1A & 1B. Each bus is an enclosed, free-standing structure rated at 2000 amperes, three phase, 60 Hz, resistance grounded wye, which limits ground fault current to 2,000 amperes and 1,000 MVA.

2. 6.9 KV bus 1A is located on the east side of 762' Auxiliary Building and 6.9 KV bus 1B is located on the west side of 762' Auxiliary building. Lockout and reset indications and controls are located on the front of the switchgear structure. The large motor loads supplied by these buses are tabulated as follows (for the entire load list, refer to CPS No. 3501.01 E001): [.1.4.5]

6.9 KV Bus 1A	6.9 KV Bus 1B
RR Pump 1A	RR Pump 1B
CW Pump 1A	CW Pump 1B
CW Pump 1C	FW Pump 1C

3. The two 6.9KV buses 1A and 1B supply eighteen 480V Unit Substations. Each substation contains a 6.9KV to 480 volt transformer. [.1.5.13]

4. Key Unit Substations have cross connecting breakers to a companion Substation that is supplied from the opposite 6.9KV bus. For certain fault conditions the source of power to these Substations will be automatically transferred.

   See Attachment L for 480 volt Substation locations.

5. Indications

   a. On MCR panel P870, 6.9 KV Bus Voltage meters for Bus 1A and 1B are provided with a selector switch for each meter to select indication from Phases A-B, B-C, and A-C or to turn the meter off.

   b. A Red Bus Energized status light is place on the mimic for Bus 1A and 1B.

c. Synchronizing instrumentation on the Switchyard section of MCR panel P870 is used when manually closing the Normal or Alternate feeders to the 6.9 KV buses. Synchronizing switches associated with each of the four feeder breakers will align the Running and Incoming voltages as appropriate to the indication on the Switchyard section.	[.1.15.1]
6. Controls and Interlocks	[.1.5.1]
a. The Main feed breakers each have an individual four position (Trip-Normal-Close, Pull-to-Lock) control switch located on P870.	[.1.15.3]
1) The associated Sync Selector Switch must be turned on and the Unit Synchronized to the Grid (permissive provided by relay logic) in order to close the breaker. There is no sync check relay on 6.9 KV buses.	[.1.15.1]
2) If the bus is being fed from the reserve feed and the main feed breaker is closed, both the main and reserve breakers will stay closed until the control switch for the main feed breaker is returned to **NORMAL** at which time the reserve breaker will automatically trip open.	
3) If the on-coming source breaker trips prior to releasing the source breaker control switch from the "After Close" position, a loss of power to the bus will not occur due to the off-going source breaker sensing the position of the on-coming breaker even though the control switch for the on-coming source breaker is taken to the "After Close" position. (Note that CPS 3501.01 High Voltage Auxiliary Power System requires the operator to place the sync switch to off before releasing the source breaker control switch if the on-coming source breaker fails to close. This is done to prevent an auto trip of the load breaker and resultant loss of the bus in the event that this interlock fails).	[.1.15.1] **HU Tools (for ensuring a bus is not inadvertently de-energized) include a pre-evolution brief and Procedural Compliance especially when an "If-Then" condition occurs during an evolution. In this case, the required actions when the source breaker does not stay closed as expected.**
b. The Reserve feed breakers each have an individual four position (Trip-Auto-Close, Pull-to-Lock) control switch which is located on MCR panel P870.	[.1.15.3]
1) The associated Sync. Selector Switch must be turned on in order to close the breaker. There is no sync check relay on 6.9 KV buses.	[.1.15.1]

2) If the bus is being fed from the main feed and the reserve feed breaker is closed, both the main and reserve breakers will stay closed until the control switch for the reserve feed breaker is returned to **AUTO**, at which time the main breaker will automatically trip open.

c. On a loss of power from the UATs (Generator Trip), the buses will automatically transfer to their respective RAT if the associated reserve feeder breakers are in the "Normal-After-Trip" position.

1) On a loss of any one or all of the RATs, the respective non-vital buses will not automatically transfer to the UATs.

2) There are no undervoltage transfer relays on the 6.9 KV Buses. The automatic transfer from Main to Reserve is initiated by logic relays.

d. If a fault occurs on a 6.9 KV bus, the main breaker trips, the reserve feed breaker is blocked from closing, the associated 480 V feed breakers trip and the associated 480 V tie breakers close.

[.1.5.5]

7. Alarms

[.1.6]

a. The automatic trip of the Main or Reserve Breaker is alarmed in the MCR (5011-1C, Auto Trip Breaker). The alarm will result from a manually initiated bus transfer as well as a fault or loss of the Generator. To reset the alarm, the tripped breaker must be "flagged" by placing the control switch to tripped for the tripped breaker causing the position flag to go from Red to Green.

[.1.15.3]

b. Loss of DC Control power for breaker control is alarmed in the MCR (5011-1E). Breakers that lose status light indication can only be tripped locally.

c. Loss of power to a 6.9KV bus will be alarmed in the MCR (5011-1F, AC Undervoltage). This condition will cause the 480V Substation breakers, fed by the bus to trip open; however, neither the Reserve nor Main breakers will attempt to reclose as a result of the detected undervoltage.

[.1.5.13]

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

d. Automatic transfer from the Main Feeder to the Reserve Feeder is alarmed by Auto XFER 6900 V Bus Reserve Feed Bkr alarm (5011-2C). If the automatic transfer to the Reserve source is blocked, a XFER Blocked alarm (5011-2D) will alarm in the MCR.

e. Refer to Attachments B through H (as applicable) for alarm details.

G. 4160 Volt Switchgear Non-Class 1E

1. The 4.16 KV non-Class 1E System includes buses 1A & 1B. Each bus is an enclosed free standing structure with buses rated at 3,000 amperes, 3-phase, 60 Hz, resistance grounded wye, which limits ground fault current to 3,000 amperes and 250 MVA. Bus in plant locations are as follows:

a. 4.16 KV buses 1A is located on 762' Auxiliary Building east side. **[.1.4.6]**

b. 4.16 KV buses 1B is located on 762' Auxiliary Building west side. **[.1.4.6]**

c. Lockout and reset indications and controls are located on the front of the switchgear structure.

2. Large motor loads supplied by the 4.16 KV Buses are as follows (for a complete list of all loads, refer to CPS No. 3501.01 E001).

4.16 KV Bus 1A	4.16 KV Bus 1B
RR M-G 1A	RR M-G 1B
CA Pump A	CA Pump B
WO Chiller A & C	WO Chiller B, D & E
CC Pump 1A & C	CC Pump 1B
WS Pump 1A & C	WS Pump 1B
SA Compressor 0	SA Compressor 1 & 2
RD Pump 1A	RD Pump 1B
CD Pump 1A & C	CD Pump 1B & D
CB Pump 1A & C	CB Pump 1B & D

3. The two 4.16 KV Non-Class 1E buses 1A and 1B supply six 480V Unit Substations. Each substation contains a 4.16KV to 480 volt transformer. There are no cross connects between the Substations. **[.1.5.13]**

4. Indications

   a. On MCR Panel P870, 4.16 KV Bus Voltage meters for Non Class 1E buses 1A and 1B are provided with a selector switch for each meter to select indication from Phases A-B, B-C, and A-C or to turn the meter off.

      1) A Red Bus Energized status light is place on the mimic for Bus 1A and 1B. **[.1.16.4]**

      2) Synchronizing instrumentation on the Switchyard section of MCR panel P870 is used when manually closing the Normal or Alternate feeders to the 4.16 KV buses. Synchronizing switches associated with each of the four feeder breakers will align the Running and Incoming voltages as appropriate to the indication on the Switchyard section. **[.1.15.1]**

5. Controls and Interlocks **[.1.5.3]**

   a. Feeder Breaker Controls **[.1.15.3]**

      1) The 4.16 KV 1A and1B Main and Reserve feed breakers each have a four position (Trip-Auto-Close, Pull-to-Lock) control switch on P870.

      2) The associated Sync. Selector Switch must be turned on and the Unit Synchronized to the Grid (permissive provided by relay logic) in order to close the breaker. There is no sync check relay on 4.16 KV buses. **[.1.15.1]**

      3) If the bus is being fed from the main feed and the reserve feed breaker is closed, both the main and reserve breakers will stay closed until the control switch for the reserve feed breaker is returned to **NORMAL**, at which time the main breaker will automatically trip open.

4) If the on-coming source breaker trips prior to releasing the source breaker control switch to the "After Close" position, a loss of power to the bus will not occur due to the off-going source breaker sensing the position of the on-coming breaker even though the control switch for the on-coming source breaker is taken to the "After Close" position. (Note that CPS 3501.01 High Voltage Auxiliary Power System requires the operator to place the sync switch to off before releasing the source breaker control switch if the on-coming source breaker fails to close. This is done to prevent an auto trip of the load breaker and resultant loss of the bus in the event that this interlock fails).

[.1.15.1]

HU Tools (for ensuring a bus is not inadvertently de-energized) include a pre-evolution brief and Procedural Compliance especially when an "If-Then" condition occurs during an evolution. In this case, the required actions when the source breaker does not stay closed as expected.

b. On a loss of power from the UATs (Generator Trip), the buses will automatically transfer to their respective RAT if the associated reserve feeder breakers are in the "Normal-After-Trip" position.

1) On a loss of any one or all of the RATs, the respective non-vital buses will not automatically transfer to the UATs.

[.1.16.4]

2) There are no undervoltage transfer relays on the 4.16 KV Buses. The automatic transfer from Main to Reserve is initiated by logic relays.

c. If a fault occurs on a 4.16 KV bus, the main breaker trips, the reserve feed breaker is blocked from closing, the associated 480 V feed breakers trip. There are no tie-breakers on the substations associated with 4.16 KV.

[.1.16.4]

[.1.5.5]

6. Alarms

[.1.6]

a. The automatic trip of the Main or Reserve Breaker is alarmed in the MCR (5012-1A, Auto Trip Breaker). The alarm will result from a manually initiated bus transfer as well as a fault or loss of the Generator. To reset the alarm the tripped breaker must be "flagged" by placing the control switch to tripped for the tripped breaker causing the position flag to go from Red to Green.

[.1.15.3]

b. Loss of DC Control power for breaker control is alarmed in the MCR (5012-1C). Breakers that lose status light indication can only be tripped locally.

c. Loss of power to a 4.16 KV bus will be alarmed in the MCR (5012-1D, AC Undervoltage). This condition will cause the 480V Substation breakers, fed by the bus to trip open; however, neither the Reserve or Main breakers will attempt to reclose as a result of the detected undervoltage.

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

d. Automatic transfer from the Main Feeder to the Reserve Feeder is alarmed by Auto XFER 4160V Bus Reserve Feed Bkr alarm (5012-2A). If the automatic transfer to the Reserve source is blocked, a XFER Blocked alarm (5012-2B) will alarm in the MCR.

e. Refer to Attachments A through G (as applicable) for alarm details.

[.1.6]

H. 4160 Volt Switchgear Class 1E

1. The 4.16 KV Class 1E System consists of three buses. Each bus is an enclosed free standing structure and are rated at 1,200 amperes, 3-phase, 60 Hz. Bus in plant locations are as follows:

   a. 4.16 KV buses 1A1 is located on 781' Auxiliary Building east side. [.1.4.6]

   b. 4.16 KV buses 1B1 is located on 781' Auxiliary Building west side. [.1.4.6]

   c. 4.16 KV buses 1C1 is located on 781' Control Building. [.1.4.6]

   d. Lockout and reset indications and controls are located on the front of the switchgear structure.

2. Large motor loads supplied by the 4.16 KV Buses are as follows (for a complete list of all loads, refer to CPS No. 3501.01 E001).

Bus 1A1	Bus 1B1	Bus 1C1
LPCS Pump	RH Pump 1B	HPCS Pump
RH Pump 1A	RH Pump 1C	
SX Pump 1A	SX Pump 1B	
FC Pump 1A	FC Pump 1B	
VP Chiller 1A	VP Chiller 1B	

3. The 4.16 KV Class 1E buses 1A1 and 1B1 each supply two 480V Unit Substations with each substation containing a 480V transformer. Ten MCCs are assigned to Division 1 and 11 MCCs to Division 2. Division 3 has three Motor Control Centers, which are fed off of one step down transformer. There are no cross connects between the substations. [.1.5.13]

   a. Nine of the ten MCCs assigned to Division 1 are Safety-related.

   b. Ten of the eleven MCCs assigned to Division 2 are Safety-related.

   c. The table below lists the safety related MCCs powered by bus 1A1 and bus 1B1.

Bus 1A1	Bus 1B1
480V Unit Sub A	480V Unit Sub B
• CB MCC E1 • CB MCC E2 • CB MCC G	• CB MCC F1 • CB MCC F2 • CB MCC H
480V Unit Sub 1A	480V Unit Sub 1B
• SSW MCC 1A • DG bldg MCC 1A • AB MCC 1A1 • AB MCC 1A2 • AB MCC 1A3 • AB MCC 1A4	• SSW MCC 1B • DG bldg MCC 1B • AB MCC 1B1 • AB MCC 1B2 • AB MCC 1B3 • AB MCC 1B4 • TB MCC 1M

4. Essential Switchgear Heat Removal System maintains the switchgear, battery, inverter rooms and cable spread areas within the design temperature limits of the equipment. If the system becomes degraded the following actions are taken.

   a. Open all doors to the overheating room. Opening the doors violates fire boundary integrity.

   b. Set up a portable air blower to cool the room.

   c. If possible, reduce electrical load on components located in overheated switchgear or inverter room.

5. Indications

   a. MCR Panel P877 has the controls and indications for Class 1E Buses 1A1 and 1B1. The 1C1 Bus indications and controls are on Panel P601.

      1) A separate 4.16 KV Bus Voltage meters for each of the Class 1E Buses is provided on the associated MCR panel. A Red Bus Energized status light is place on the mimic for each bus. **[.1.16.4]**

2) The two synchroscopes (Division 1 & 2 1E buses) on P877 have Running and Incoming Voltmeters with a range of 0-5250 volts. There is also a slow-fast indicator with two white voltage indicator lights located above the voltmeter for each of the synchroscopes. The lights indicate if the running bus and/or the incoming bus are in phase. The slow-fast indicator is used to indicate the frequency difference between the two sources on either side of the breaker that has been selected to parallel across. The synchroscopes are common to each division's 4.16 KV buses main and reserve feed breakers and the D/G output breaker.

3) The synchroscope for the Division 3 safety related bus on MCR Panel P601 is similar to the synchroscopes for Division 1 & 2.

4) There is an individual, key locked, two position (Off-On) Sync selector switch for 4.16 KV bus 1A1, 1B1 and 1C1 main, reserve and D/G feed breakers that is used to select the associated division's synchroscope. Each of the switches is located above its associated breaker control switch on MCR panel P877 (Division 1 & 2) and P601 (Division 3). **[.1.15.1]**

5) Local Indications **[.1.4.6]**

   a) The main and reserve 4.16 KV supply breaker each has an ammeter selector switch that is selectable for each phase (A-B-C) and one ammeter each (0-600 amps).

   b) The 4.16 KV HPCS Transformer feeder breaker is equipped with a transformer current selector switch that selects for each phase (A, B, C), and one ammeter (0-75 amps).

   c) The 4.16 KV bus Auxiliary Compartment has a bus potential voltmeter selector switch (Off, A-B, B-C, C-A) and a Bus 1C1 voltmeter (0-5250 volts). Bus 1C1 current can be read on P601 using the ET 4 Normal or Alternate Feeder indication.

6. Controls and Interlocks [.1.5.3]

   a. Feeder Breaker Controls

      1) The 4.16 KV 1A1, 1B1 & 1C1 Main, Reserve and D/G feed breakers each have a four position (Trip-Auto-Close, Pull-to-Lock) control switch on P877 (Division 1 & 2) and on P601 for Division 3. [.1.15.3]

      2) The associated Sync. Selector Switch must be on and the synchronization check relay satisfied to manually close any of these breakers. [.1.15.1]

         a) Ensuring that the equipment being paralleled is synchronized with each other prevents equipment damage.

         b) Typically, the phases are required to be within 20°. The relay senses voltages on both sides; if one side is not energized, this condition bypasses the synchronization relay to allow energizing the line that is de-energized.

      3) If the bus is being fed from the main (reserve) feed and the reserve (main) feed breaker is closed, both the main and reserve breakers will stay closed until the control switch for the reserve (main) feed breaker is returned to NORMAL. When the switch is released the main (reserve) breaker will then automatically trip open. If the on-coming source breaker trips prior to releasing the source breaker control switch to the "After Close" position, a loss of power to the bus will not occur due to the off-going source breaker sensing the position of the on-coming breaker even though the control switch for the on-coming source breaker is taken to the "After Close" position. (Note that CPS 3501.01 High Voltage Auxiliary Power System requires the operator to place the sync switch to off before releasing the source breaker control switch if the on-coming source breaker fails to close. This is done to prevent an auto trip of the load breaker and resultant loss of the bus in the event that this interlock fails).

         [.1.15.1][.1.15.3]

         HU Tools (for ensuring a bus is not inadvertently de-energized) include a pre-evolution brief and Procedural Compliance especially when an "If-Then" condition occurs during an evolution. In this case, the required actions when the source breaker does not stay closed as expected.

      4) Automatic transfer is available between either source breaker if the incoming feeder breaker, has 4.16 KV

power available, the closing and tripping DC control power for the breakers is available, incoming breaker control switch is in the "NORMAL-AFTER-TRIP" position, and the Lockout Relays are not tripped.

5) The Division 2 ESF bus breakers for RHR pump 1B and SX pump 1B may be operated from the locally mounted control switch if the associated local Remote Shutdown control switch is selected to "Emergency"(refer to the Remote Shutdown lesson plan for further details).

b. Loss of Power (LOP) Instrumentation

[.1.5.11][.1.5.12][.1.16.4]

1) The Loss of Power (LOP) Instrumentation monitors the 4.16 KV Class 1E emergency buses. If the monitors determine that insufficient off site power is available, the Emergency Diesel Generator is automatically started and a bus transfer sequence is initiated to restore an adequate power source.

Note that DGs also start on LOCA signals.

2) Each 4.16 KV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for the Division 1, 2, and 3 buses is monitored by two different undervoltage functions: Loss of Voltage (1st Level) and Degraded Voltage (2nd Level).

3) The First Level, Loss of Voltage, is indicative of a loss of offsite power. It uses a low voltage setting of ~2870V (Div 1 and 2) and ~2538 (Div 3) with a short 2 sec time delay.

[.1.5.12]

4) The Second Level, Degraded Voltage, indicates that while offsite power may still be available it may be insufficient for starting large motors without risking damage to the motors due to excessive starting currents. Attempting to obtain the required power with degraded voltage requires higher currents. It uses low voltage setting of ~4072 V with a longer, 15 sec time, delay.

[.1.5.11]

5) Each Division 1 and 2 emergency bus Loss of Voltage Function is monitored by two undervoltage relays on the emergency bus and two undervoltage relays on each of the two offsite power sources. The outputs of these relays are arranged in a two-out-of-two taken three times logic configuration. Each of

these relays is an inverse time delay relay. Alarms in MCR (5060-3C, 5061-3C)

6) The Division 3 emergency bus Loss of Voltage Function is monitored by four undervoltage relays on the emergency bus whose outputs are arranged in a one-out-of-two taken twice logic configuration. The output of this logic inputs to a time delay relay. Alarms in MCR (5062-3B)

7) Degraded Voltage Function logic is identical for Division 1, 2, and 3 emergency buses. Degraded Voltage Function is monitored by two undervoltage relays with contacts arranged in series (a two-out-of-two logic) configuration. The output of this logic inputs to a 15 second time delay relay. Alarms are provided in MCR for Div 1 and 2 5060-3D, 5061-3D) A direct alarm for Div 3 is not provided. The condition would be indicated by Auto XFER 4160V Bus RES/DG Feed Bkr alarm 5062-1B.

[.1.6]

8) A Loss of Power condition on a 4.16 KV safety related bus while power is provided from the normal (reserve) source, will cause the normal (reserve) source to automatically trip and the reserve (normal) source to close and pick up loads depending upon the following considerations.

If a fault or overload exists on the bus the normal (alternate) breaker will not close in.

a) Differential overcurrent lockout on the main source will cause a fast transfer to the reserve source, if it is available. No loads should be lost. Other conditions locking out the main source are slower to react and loss of loads should be anticipated.

b) Automatic slow source transfer of a bus occurs if all source breakers are open for any reason and a fast source transfer has not resulted due to bus protective action and the other source being "available" to the bus at the instant all source breakers become open. This takes approximately 2.5 seconds for Div 1 and 2. Div 3 is very quick.

c) If the reserve (normal) source voltage is also low and the 1st Level Undervoltage logic times out, then the Diesel Generator (DG) will start and the DG output breaker closes. The DG does not auto start unless both the main and reserve feed power sources and associated breakers are not available.

d) If the 2nd Level Undervoltage logic times out (15 sec), the Diesel Generator auto starts, Reserve(Main) feeder will open, the Main(Reserve) feeder locks-out, the bus loads are stripped, and DG closes in.

e) The loads on the bus will be stripped and sequentially loaded onto the DG if the associated ECCS initiation signals are present.

If DG output breaker auto trips, do <u>not</u> attempt to reclose the breaker.

f) If several sources become available to the bus after the loads are shed, due to bus undervoltage, the breaker for the source that becomes available first is closed. If several sources become "available to the bus" at the same instant, the RAT 'B' source breaker will have preference.

g) There is no automatic transfer back to the normal, or reserve power source from the DG should the normal, or reserve source be restored.

c. Undervoltage Relays

[.1.16.4]

1) Loss of Power signals are sensed by potential and control power transformers.

a) There are 4 Potential Transformers on each of the 1A1 and 1B1 buses and 3 Potential Transformers on the 1C1 bus.

b) On the 1A1 and 1B1 buses there is a Potential Transformer on each of the main and reserve power sources, on DG power source and one off of the bus itself.

c) The 1C1 bus has only 3 and is the same as the 1A1 and 1B1 with the exception that there is no Potential Transformer for the DG source as it is located in the DG control panel.

d) Two of the three power distribution phase-pairs are continuously monitored by the undervoltage relays to detect a degraded or loss of voltage condition. Phase pair A-to-B are monitored in addition to phase-pair B-to-C. A degraded or loss of voltage in BOTH phase-pairs must be sensed before the bus logic responds.

This turns out to be a vulnerability and limitation in the undervoltage sensing logic. If, for example, phase 'C' was lost (no phase 'C' voltage) but sufficient voltages remained on phases A & B, only one of the two phase-pairs would 'see' loss of phase 'C' and no automatic actions would occur to help protect important loads.

The vulnerability described here became apparent during the Byron event when the 345 KV 'C' phase (feeding off-site sources) open-circuited. This condition was not sensed by the protection logic. See Attachment O for further information.

2) The potential and control power transformers, up to 15 KVA, single phase, are enclosed within their own compartments. They are mounted on a cradle, which is linked to the door of the compartment.

10/98 at CPS, while in Cold Shutdown Bus 1A1 was momentarily de-energized causing the loss of Shutdown Cooling. An operator opened the wrong PT compartment while attempting to replace fuses from a clearance order. DG 1 started and closed in on the bus. This will be reviewed in detail later.

a) When the door is closed, both the primary and secondary disconnecting contacts are engaged.

b) When the door is open, the cradle and transformers are automatically rotated about a horizontal axis disconnecting both the primary and secondary contacts, and grounding the fuses (PT Fuses) and the high voltage windings of the transformers.

(a) A shutter comes down to block access to the primary contacts, and a catch secures the door in the open position. In this position the fuses may be safely removed.

(b) This also causes low voltages (no voltage) to be sensed by the undervoltage relays resulting in Bus transfers and possible DG startup and tie onto the bus.

(c) The PT fuses are contained in door type cabinet enclosure sitting on top of the switchgear or mounted flush with front of switchgear. On Division 3 the Bus and Main Feed PT Fuses are contained in a drawer type enclosure inside Auxiliary Compartment.

d. Diesel Generator Operations

[.1.15.1]

1) If the bus is paralleled between the associated DG and either the main or reserve feed, turning the DG Sync. Selector switch to "Off" will trip the DG feed breaker.

2) If the associated DG trips or a LOCA signal is received while the D/G is paralleled, the DG breaker will trip open. If a LOCA signal causes the DG output breaker to trip open while it is paralleled and a subsequent bus undervoltage occurs, the DG breaker will automatically reclose and loads will be sequentially placed onto the bus (depending upon ECCS initiation signals). **[.1.16.5]**

3) The DG output breaker has an overcurrent trip. This trip is bypassed when a LOCA signal is present. **[.1.16.5]**

4) If the DG output breaker trips while the DG is the only supply tied to the Class 1E 4160V bus, the bus will not automatically re-energize from an off-site source. Manual operator action is required to restore vital bus power from off-site sources. **[.1.16.5]**

5) Due to the potential for a fault to adversely impact the off-site sources, the use of the Offsite Source Permissive push-button shall not be used to re-energize a Class 1E 4160V bus unless an in-use surveillance or test procedure specifically directs the use of this function.

7. Alarms

a. The automatic trip of the Div 1 or 2 Main, Reserve, or Diesel Generator Breaker is alarmed in the MCR (5060-1B, 5061-1B). The alarm will result from a manually initiated bus transfer as well as a bus fault. To reset the alarm the tripped breaker must be "flagged" by placing the control switch to tripped for the tripped breaker causing the position flag to go from Red to Green. **[.1.6]** **[.1.15.3]**

b. Division 3 is provided with individual automatic breaker trip alarms for the Main, Reserve and DG output breakers (5062-1A, and 1C, 3A).

c. A 4160V Bus Breaker Not Available alarm (5060-1D, 5061-1D) indicates that one or both of the offsite power source feeds is not available. This could be due to F or S System actuation on RT 4 and/or ET 4, breaker overcurrent trip, loss of control power, or breaker maintenance.

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

d. The initiation of a transfer sequence from the Main Feeder to either the Reserve Feeder or DG is alarmed by Auto XFER 4160 V Bus alarm (5060-2B, 5061-2B, and 5062-1B). The alarm actuation does not imply that the transfer was successful. Failure of the transfer may be accompanied by a XFER Blocked alarm (5060-2C, 5061-2C, and 5062-2B). This alarm may be cause by overcurrent trip of a feeder breaker, breaker maintenance, or a bus fault.

e. Loss of DC Control power for breaker control is alarmed in the MCR (5060-3A, 5061-3A, and 5062-7A). Breakers that lose status light indication can only be tripped locally.

f. Refer to Attachments B through H (as applicable) for alarm details.

I. 480 Volt Unit Substations

[.1.5.13]

1. The unit substations are fed from their associated 6.9 KV and 4.16 KV buses. There are 28 unit substations supplying 111 MCCs plus 2 Hydrogen Igniter Panels, which are actually MCC type equipment.

2. See Attachment L for the 480 volt Substation locations.

3. Refer to CPS 3502.01E001 (480 VAC Distribution Electrical Lineup) for a complete list of physical locations of 480 VAC Substations and associated Motor Control Centers (MCCs).

4. Risers (also known as Plug-in Buses) provide convenient tap-off points to the 480 V bus from selected substations. They are used to conveniently power loads such as welding receptacles and lighting panels. Other loads can be mounted to the riser in either a permanent or temporary configuration, as needed. Riser access points are segmented to allow breaker box installation. Riser covers (which provide a barrier to the underlying 480 V bus) must be in place for personnel safety and should only be removed by authorized maintenance personnel.

5. 480 VAC Unit substations typically supply motors between 250 and 50 horsepower and have transformers with supplemental fan(s) cooling to increase their load capability.

6. If normal power is lost to some of the 480V Substation supplied by 6.9 KV, power can be restored to the 480V substation via a 480 V cross-tie breaker.

[.1.5.5]

7. All breaker activities performed on OPERABLE switchgear shall be evaluated for switchgear operability and seismic qualification per CPS No. 1014.11, 6900/4160/480V SWITCHGEAR/CIRCUIT BREAKER OPERABILITY PROGRAM.

   a. This includes, but is not limited to, opening the cubicle door and racking operations.

   b. When verifying breakers racked in, verify that the charging spring motor circuit is energized (on breakers that are so equipped).

8. 480 Volt Transformers

   a. The transformer sources in the substations are low resistance grounded through a grounding resistor to limit maximum ground fault current to 1200 amperes. The 480 V system is solidly grounded.

   b. A three position control switch (Auto-Hand-Off) operates the transformer cooling fans. In Hand, the fan runs continuously; in Auto, the fan cycles automatically to control transformer temperature.

      1) 480 V transformers are equipped with local winding temperature indication.

      2) A high temperature condition is alarmed by 5011-3G for 6.9 KV and 5012- 4D for 4.16 KV. These alarm procedures provide the computer points to aid in identifying the alarming transformer. **[.1.6]**

9. Indications

   a. 480V Buses voltages are monitored on P870 using a network of selector switches and 0 to 600 volt meters for the non-Class 1E 6.9 KV and 4.16 KV systems. Panel P877 has a similar arrangement for Division 1 and 2 Class 1E systems. Division 3 has a single voltage meter for 480V Bus 1C.

   b. A separate current meter is provided for each 480V Bus supplied by the non-Class 1E 6.9 KV and 4.16 KV systems. Panel P877 has the same arrangement for Division 1 and 2 Class 1E systems. Division 3 does not have current indication on P601 specifically for 480V loads.

10. Breaker Controls

a. The feeder breaker control switches are four position (Trip-Normal-Close, Pull-to-Lock). A single feed breaker, from the non-Class 1E 6.9 KV or 4.16 KV buses, will generally supply two 480 VAC Bus transformers.

b. Division 1 and 2 distribution has a single feed breaker on each 4160 V Bus that supplies two transformers (1A & A and 1B & B). The control switches for these breakers are located on P877. Division 1 4160 feeder 252-AT 1AA1 can also be controlled from the Remote Shutdown Panel (RSP).

[.1.4.6]

c. Division 3 has only one 480 V transformer, 1C. The control switch for the supply breaker is located on P601.

d. The 480 V bus tie-breaker control switches (1L &1M, 1D & 1E, 1H & 1I, C & D and O & P) are four position, and located on P870. The cross-tie breakers can be manually closed with both normal feed breakers closed, the following notes apply to this operation.

[.1.5.5]

1) Short duration paralleling is acceptable in the event it is desirable not to interrupt power to a 480V Bus. However, when two buses are paralleled, the available fault current is above the short circuit rating of the breakers. A fault occurring at this time would almost certainly cause breaker failure and equipment damage. Time spent in this condition should be kept to a minimum.

2) Prior to paralleling two 480V Buses, ensure there is < 5° phase angle difference between the two sources by checking across a 6.9 KV feeder breaker with the Sync Switch. There are no interlocks; this is a procedure requirement.

3) CPS No. 3502.01, 480VAC Distribution also provides for a "Drop and Pick-up Method" method for transferring 480V buses.

4) Maximum allowable amperage of the 480V bus pairs:

   a) 480V Bus C & D: 112 amps

   b) 480V Bus 1H & 1I: 112 amps

   c) 480V Bus 1L & 1M: 84 amps

e. Unit substation main feed breakers that cannot be operated from the MCR have local operating panels. These panels are wall mounted remotely from the 480 V main feed breaker. The wall-mounted units contain push buttons to close and trip the breaker, and have red and green lamp indication. Bus mimics in the Main Control Room have red (energized) lamp indication for these breakers. Refer to Attachment M for locations. [.1.5.13]

11. Relay Protection and Interlocks

a. The Unit Substation Transformer Breakers that feed two unit substations are equipped with an instantaneous overcurrent and timed overcurrent automatic trip relay for ∅ (phase) A, ∅B, and ∅ C, and an individual ground fault relay for each of the unit substations that they feed. [.1.5.13]

b. The Unit Substation Main Feeder Breakers that are the feed to an individual unit substation are equipped with an instantaneous overcurrent and timed overcurrent automatic trip relay for ∅A, ∅B, and ∅C, and a ground fault relay for the unit substation that they feed.

c. An undervoltage condition on 6.9 KV or 4.16 KV supply bus will trip the associated 480V Transformer Breakers and 480V Main Feeder Breakers. In the 6.9 KV distribution system the 480Vbuses with cross-connects, the tie breaker closes if the 480V feeder is tripped. [.1.5.5] [.1.4.5]

d. An overcurrent trip on the Transformer and Main Feeder Breakers will block closure of the Tie Breakers where they are provided. The Tie Breakers also have an overcurrent trip protection. [.1.5.5]

12. Alarms

a. Computer points can be used to identify which non-Class 1E Main Feeder Breakers have tripped. The computer points are listed in the associated alarm procedures (5011-3D, 5012-3B).

[.1.6]

b. Annunciators 5011-3D and 5012-3B each serve as common alarms for the respective Unit Subs they monitor. The respective alarm can be cleared once the affected Unit Sub causing the alarm is identified. If the affected Unit Sub tripped on overcurrent, resetting (pressing in) the white tab on the Unit Sub breaker will clear the respective annunciator. This allows the annunciator to warn of other Unit Sub breaker trips.

HU Tools (for addressing annunciators) include Procedural Compliance (as directed by ARPs and related procedures) in addition to using confirmatory indications in accessing actual plant/ equipment status.

c. Computer points can also be used to determine which non Class 1E 480V substation have lost DC Control Power by referencing the associated alarm procedure (5011-3E, 5012-3C)

[.1.5.13]

d. Automatic breaker operation and undervoltage are alarmed on P870, P877, and P601. Refer to Attachment C, D, E, and F.

e. Refer to Attachments A through G (as applicable) for alarm details.

J. 480V Motor Control Center (MCC)

1. The 480 V Motor Control Centers are mostly fed from the 480 V unit substations. There are 111 MCC plus 2 Hydrogen Igniter Panels that are actually MCC type equipment. A few MCCs are powered off of the 12KV loop.

2. MCC supply power for 480 V motors up to 50 HP. Those breakers, which supply a load in the Containment or Drywell, are equipped with double breakers to protect the Containment and Drywell penetrations from overcurrent conditions and thus satisfy the design criteria for the penetration.

3. Many of the 480 V MCCs include 480-208/120 V non-regulating and regulating transformers and distribution panels.

4. Refer to CPS 3502.01E001 (480VAC Distribution Electrical Lineup) for the location of MCCs which are fed from 480-volt substations.

[.1.3.9]

V. Interlocks

A. Fault Protection

1. Fault protection for the transformers and various distribution systems are addressed in the Components, Section IV.

2. A summary of the relay nomenclature used in the Auxiliary Power System is as follows:

   a. Overcurrent-Instantaneous Relay (Type 50) protects the switchgear and supply equipment due to high phase current exceeding a predetermined value during an instantaneous time period. Relay trip is indicated by a red flag dropping inside the relay box on the switchgear. **[.1.5.10]**

   b. Overcurrent-Time Relay (Type 51) protects the switchgear and supply equipment due to high phase current exceeding a predetermined value over a calibrated time period. A trip is indicated by a red flag. **[.1.5.10]**

   c. Ground-Overcurrent Instantaneous Relay (Type 50G) protects the switchgear and supply equipment due to high phase current to ground. A trip is indicated by a red flag. **[.1.5.10]**

   d. Neutral-Overcurrent Time Relay (Type 51N) protects the switchgear and supply equipment due to high phase unbalance loading exceeding a predetermined value over a calibrated time period. A trip is indicated by a red flag. **[.1.5.10]**

   e. Under-Voltage Relay (Type 27) monitors loss of voltage or degraded voltage at the switchgear. A trip is indicated by a red flag.

   f. Lockout Relay (Type 86) trips ACB's and blocks closing of the ACB's. When an 86 relay has been tripped the problem is serious and shall be fully investigated before the relay is reset. The relay trip is indicated by lights on the switchgear and is reset by a switch located on the switchgear.

   g. Alarm Relay (Type 74) is a device other than an annunciator, which is used to operate, or to operate in connection with, a visual or audible alarm.

h. Differential Protective Relay (Type 87) is a protective device which functions on a percentage of phase angle or other quantitative difference of two currents or of some other electrical quantities. [.1.5.9]

3. CPS 4200.01 LOSS of AC POWER, includes Trip Data Sheets that list all of the relays associated with the loss of major electrical distribution centers listed below. When a lockout occurs it is imperative that these forms are filled out completely to support the post event analysis.

D001,	Main Generator
D002,	RAT A,(B),[C]
D003,	ERAT
D004,	6900V Bus 1A
D005,	6900V Bus 1B
D006,	4160V Bus 1A
D007,	4160V Bus 1B
D008,	Emergency Bus 1A1
D009,	Emergency Bus 1B1
D010,	Emergency Bus 1C1
D011,	Switchyard

B. Unit Synchronization Relays (U-Z)

1. These six relays are normally energized when MOD 4508 is closed AND either GCB 4506 OR GCB 4510 is closed. These conditions are used to indicate that the Main Generator is on line and power is available to Auxiliary Power System through the Unit Auxiliary Transformer.

2. Through use of these relays the following interlocks are satisfied.

   a. Unit Auxiliary Transformer feeder breakers to 4.16 KV and 6.9 KV buses 1A and 1B may be closed. Loss of these relays will initiate a transfer of the 6.9KV and 4.16KV Buses to the respective RAT.

b. The EXCITER FLD CONTROL switch at P680 in the MCR is interlocked with the unit sync relays such that the operator cannot manually turn off Exciter field excitation while the Main Generator is loaded (synchronized to the grid).

c. Turning Gear Motor start permissive is fed by the relays.

C. Loss of Coolant Accident Response

1. During operation when offsite power is available a Loss of Coolant Accident (LOCA) will cause the Emergency Diesel Generators to start and to run idle.

- **Working Effectively as a Team**

a. Emergency loads are sequenced on even though offsite power is available. RHR Pumps A and B start is delayed by 5 second, SX Pump 1A and 1B are delayed by 10 seconds, and the other emergency loads promptly start.

b. Shunt trips are actuated stripping non-Class 1E loads from the Class 1E Buses. Selected Class 1E loads are shed.

2. If a loss of all offsite power occurs in conjunction with a LOCA, the Emergency Diesel Generators start, non-Class 1E loads are shunt tripped, and the Class 1E bus loads are shed except Substation feeders.

[.1.5.13]

a. RHR Pump A and B start is delayed by 5 seconds, SX Pump 1A and 1B start is delayed by 10 seconds, and the other emergency loads promptly sequence on as soon as the Class 1E Bus power is available from the associated DG.

b. Balance of Plant loads from non-Class 1E 6.9KV and 4.16KV buses are lost when the Main Generator Lockout is actuated.

3. The Shunt Trips and the selected Class 1E loads which are shed are listed in CPS 4001.02 AUTOMATIC ISOLATION in Table 1. The resetting of the shunt trips and restoration of loads that are shed is addressed in the respective system operating procedures.

D. Station Blackout

[.1.9]

1. A Station Blackout is the total loss of offsite AC power sources (including Main Generator), and failure of Div 1 & Div 2 DG power sources. The Auxiliary Power System will respond as described for LOOP depending on plant conditions.

2. Div 3 AC power source is in excess of the number required to meet the minimum redundancy requirements (i.e., single failure) for safe shutdown. For extended SBO conditions, it should be referenced for strategies the ERO could employ to supply Div 1 or 2 ECCS busses from the Division 3 Diesel Generator to support decay heat removal. RCIC is the other source of cooling.

3. AC power loss is assumed for all operating AC equipment including nuclear instruments, level indication and RPV metal temperatures powered from the ECCS and non-ECCS buses, and a loss of all AC lighting.

    a. As long as DC buses are available, instrumentation may be available where powered by un-interruptible supplies, such as the NSPS ATMs.

    b. CPS 4200.01 Loss of AC Power directs you to CPS 4201.01C002 DC Load Shedding which provides direction for manually decreasing loads on the station batteries to prolong the availability of critical DC loads and instruments.

4. Operator Time Response during a Station Blackout

    a. ATLAS Database assumes operator take actions in 10 minutes to control RPV level and pressure.

VI. Controls/Instrumentation/Power Supplies

Controls, Instrumentation and Power Supplies for the Auxiliary Power System is addressed with the associated major components in Section IV.

VII. Interrelationships

A. Support Systems	[.1.7]
1. Main Generator	
a. Generator output of approximately 22 KV is supplied to the UATs for in house loads. The UATs step the voltage down from 22 KV to 6.9 and 4.16 KV. A UAT fault will trip and lockout the Main Generator.	
2. Switchyard	
a. The 345 KV and 138 KV Switchyard supplies two independent sources of offsite power to the Auxiliary Power System through the three RATs and ERAT.	
b. Static Var Compensators are installed on the secondary sides of RAT 'B' and the ERAT to help maintain plant voltage for the 4.16 KV safety buses during transient conditions on the offsite system.	
c. 138 KV through the 12 KV distribution system supplies some Auxiliary Power loads.	
3. Emergency Diesel Generators	
a. Supply emergency power to the associated Class 1E buses.	
b. The Auxiliary Power System allows a load connection for the D/Gs to accomplish surveillances on the D/Gs.	
c. The Auxiliary Power System provides an auto start signal to the D/Gs on an associated ESF bus degraded or undervoltage condition.	[.1.5.11][.1.5.12]
4. 125 VDC Electrical Distribution	
a. Supplies control power to all the Air and Vacuum Circuit Breakers in the Auxiliary Power System.	
b. Loss of DC Control power will result in the breakers' inability to close or open remotely or automatically. Inoperable breakers can be identified by a loss of status light indication. Manual operation can be done in an emergency, but is not desirable.	

5. Fire Protection

   a. Each RAT uses Protecto-wire to detect excessive heat generation (or fire) at the respective transformer which provides ties into the Fire Protection system for annunciation and alarm.

   b. Fire protection portion of the Auxiliary Power system initiates a FP deluge on certain conditions such as sudden pressure (UATs, RAT 'B' & ERAT) or a fast lockout condition (RAT 'B' & ERAT). The deluge system can also be manually initiated. A FP deluge initiation on the UATs, RAT 'B' or ERAT will automatically trip off the cooling system for these transformers.

6. Essential Switchgear Heat Removal System

   a. Maintains the switchgear and cable spreading areas within the design temperature limits of the equipment.

   b. The Essential Switchgear Heat Removal System is required to support the Technical Specification operability of the AP System.

   c. The switchgear rooms are also maintained at a positive pressure as an aid in maintaining cleanliness.

7. Plant Process Computer (PPC)

   a. PPC provides indication of the status of the AP System components, including transformer and bus voltages, currents, transformer temperatures, and status of certain important relays in the AP system.

B. Systems Supported — **[.1.8]**

1. Refer to Section IV, Components. Major loads supplied by the high voltage buses are listed.

2. CPS 3514.01 BUS/UNIT SUB OUTAGES provides an index of the check sheets that may be used to identify the loads from the Auxiliary Power System.

VIII. Technical Specifications

A. Safety Limits

1. None

B. Limiting Conditions for Operation (LCOs)

1. 3.3.8.1 - Loss of Power (LOP) Instrumentation — [.1.12][.1.14]

Example:

a. Plant is in Mode 1.

b. The Degraded Voltage Time Delay function was discovered INOPERABLE for Division 1 safety bus (see Table 3.3.8.1-1).

c. The affected channel will not become OPERABLE again within the next two weeks.

What is the LCO impact on the Division 1 DG and when?

2. 3.8.1 - AC Sources - Operating — [.1.12] [.1.14]

What constitutes an offsite source? Example:

a. Plant is in Mode 1.

b. Time = 0 - Security has reported that a wooden 138KV pole north of the main parking lot is on fire. Ameren/IP has been called. (Actual event occurred at CPS on 4/23/08)

c. Time = + 5 minutes - Ameren/IP has de-energized the 138 KV line between Bloomington and Decatur.

What LCO actions are required to be performed for this event?

d. Due to loss of the 138 KV line, one offsite circuit is INOPERABLE.

e. Enter the following LCO actions:

1) 3.8.1 Action A.1 - Perform SR 3.8.1.1 (CPS 9082.01) within 1 hour and once per 8 hours thereafter **AND** — [.1.13]

2) 3.8.1 Action A.2 - Restore offsite circuit to OPERABLE status within 72 hours **AND**

3) 3.8.1 Action A.2 - Restore offsite circuit to OPERABLE status within 17 days of discovery of failure to meet the LCO (for this example, meeting the 72 hour action satisfies this action).

3. 3.8.2 - AC Sources - Shutdown

[.1.12] [.1.14]

   a. Plant is in Mode 5.

   b. HPCS system is required to be OPERABLE.

   c. The ERAT is de-energized for an extended outage.

   d. Division 3 DG was just declared INOPERABLE.

   What is the LCO impact if Division 3 DG is not restored to OPERABLE status until 4 days from now?

   HPCS must be declared INOPERABLE if Division 3 DG not restored to OPERABILITY within 72 hours as directed by LCO 3.8.2 C.1.

4. 3.8.9 - Distribution Systems- Operating

[.1.12] [.1.14]

   What constitutes an AC Distribution system?

5. 3.8.10 - Distribution Systems- Shutdown

[.1.12] [.1.14]

   What AC Source are required when Shutdown?

Potential impact of a degradation of Non-segregated Phase Bus Ducting on LCOs 3.8.1 / 3.8.2 / 3.8.9 / 3.8.10 – These LCOs could be potentially impacted (i.e. Required Actions entered) based on degradation of a Non-segregated Phase Bus duct going from a safety related source to safety (divisional) loads, especially if the reliability, voltage & current requirements of the ducting cannot be met. Determination of the Operability impacts of degraded Non-segregated Phase Bus Ducting would most likely require an engineering evaluation of the degraded condition.

Recent CPS OPEX involved finding a degraded (sagging) rubber alignment joint on bus RT14 supplied by RAT 'B'.

See IR 1309865 for more information.

Content/Skills	Activities/Notes
C. Operating Requirement Manual 1. 2.5.1 Containment Penetration Conductor Overcurrent Protection Devices. a. What action is required for an inoperable 6.9 KV breaker while in Mode 1, 2 or 3? 1) Evaluate the system(s) affected by the 6.9 KV breaker for OPERABILITY and enter the appropriate Technical Specification and/or ORM ACTION. 2) For 6.9-KV circuit breakers, remove the 6.9-KV circuit(s) from service by racking out the breaker within 72 hours and verify the inoperable breaker(s) to be racked out at least once per 7 days thereafter.	**[.1.12]** **https://www.youtube.com/watch?v=2WlN7iO-cfk [.1.14]**

IX. Operational Characteristics

A. Precautions and Limitations

1. CPS 3501.01 - HIGH VOLTAGE AUXILIARY POWER SYSTEM PRECAUTIONS

[.1.10]

a. When operating the Auxiliary Power System the operator must ensure that only one Sync Selector Switch per Synchroscope is placed ON at a time. Failure to do this can result in equipment damage.

b. When closing any 6900V or 4160V breaker on an energized bus, synchronization and voltage match must be verified to prevent equipment damage.

c. Before attempting to restore systems following a power outage (i.e., Station Black Out or Bus Outage), ensure that power is available/restored to the radiation monitors prior to restoring power to the trip system logic. This is to avoid inadvertent actuations and/or isolations.

d. The Main/Reserve supply breakers to the 6900V and 4160V buses should not be held in the CLOSE position longer than 5 seconds to preclude an undesirable trip due to circulating current between the sources (RAT/ERAT/UAT).

- **Operating the Plant with a Conservative Bias**

e. All breaker activities performed on OPERABLE switchgear shall be evaluated for SWITCHGEAR OPERABILITY/SEISMIC QUALIFICATION per CPS 1014.11, 6900/4160/480VSwitchgear/Circuit Breaker Operability Program. This includes, but is not limited to, opening the cubicle door and racking operations.

   1) Prior to racking out or in a 4160V or 6900V breaker, remove the control power fuses.

   2) When verifying breakers racked in, verify that the charging spring motor circuit is energized (on breakers that are so equipped).

f. Many loads, powered (directly or indirectly) from the 6900V or 4160V buses, are designed with automatic start capability. To minimize the current surge, during bus restoration, the unwanted automatic start of major loads is prevented. This procedure provides direction for preventing the automatic start of those loads that are directly powered from the 6900V or 4160V buses.

   480V Unit Subs are energized and de-energized per CPS 3502.01, 480VAC Distribution.

   CPS 3514.01, Bus/Unit Sub Outages checklists, loading diagram E02-1AP03, and bus load lists may be checked to determine if there are other loads, with automatic starting capability, that could have a significant impact on bus restoration or plant operation.

g. Potential Transformer (PT) Cubicles associated with the Safety Related 4160V Bus 1A1, 1AP07E (1B1, 1AP09E) [1C1, 1E22-S004] should not be opened when the bus is energized.

   Opening the door can cause ESF actuations including tripping of the ECCS bus and DG auto starts.

   Each PT Cubicle is labeled as such, and Div 1(2) PT Cubicles (2 each) are pad locked.

h. In the case of RAT 'A' (1AP02EA) primary LTC controller (M-2001B) failure, RAT 'A' secondary terminal voltage must be above the minimum acceptable level of 6845V to start 6.9kV motors (Calc 19-AN-37).

i. WHEN both 6.9kV buses are connected to RAT 'A' (1AP02EA) in MODE 1 at 100% power (loaded with both RR pumps, 3 CW pumps and MDRFP), THEN Increased monitoring of RAT 'A' (1AP02EA) temperature should be conducted (3800.02C005 Switchyard and Transformer Log) to prevent overloading damage (Calc 19–AK-13).

j. All switching operations on 4160V and 6900V disconnects shall be performed using written instructions by qualified personnel.

Written instructions shall be reviewed and approved/ initialed by the SMngt prior to performing switching instructions.

Switching instructions are to be prepared and performed as follows:

1) The instructions will be prepared on Switching Order Form 302-2, if available. The Switching Order number should be left blank.

2) The Switching Order shall clearly state the reason for the switching and give sequential steps for the switching evolution and include verification of the status of components not operated that are important to the safe operation.

3) Ensure disconnect switches are not operated under load.

4) Remotely operated breakers used to interrupt power flow during disconnect operation should have their remote control switches danger tagged open to prevent remote operation.

5) The status of Tagouts and Hold cards shall be reviewed prior to preparing the Switching Order to ensure that the Switching Order does not conflict, causing a tagged component to be operated.

6) Switching orders shall be conducted by at least 2 SY Area qualified operators (normally 'E' Area operators, but may be specially qualified for switchyard work, e.g., qualified electrical maintenance personnel or lineman).

   One of the qualified personnel shall observe the performance of the Switching Order, verifying the order is performed as written.

7) The persons performing the switching share the responsibility with the SMngt. They shall call to the SMngt's attention any condition causing them to believe the Switching Order is in error.

8) Prior to performance of the Switching Order, the individuals performing the switching shall discuss the operation with the initiating supervisor. Each individual should read the Switching Order in its entirety and using applicable drawings or mimics indicate each component to be checked or operated.

9) Completed Switching Orders initiated by the SMngt should be forwarded to the Operations Support Group.

2. CPS 3501.01 - HIGH VOLTAGE AUXILIARY POWER SYSTEM LIMITATIONS

[.1.10]

a. If the 4160V Bus 1A1(1B1)[1C1], or any of the buses' potential power supplies are degraded, refer to:

1) ITS LCOs 3.8.1/2 (CPS 9082.01, Offsite Source Power Verification)

2) ITS LCOs 3.8.9/10 (CPS 9082.02, Electrical Distribution Verification)

b. Reclosure of a breaker that has tripped due to electrical protection logic should not be attempted except in emergency situations, and then only when reclosure can be performed remotely to prevent hazard to personnel should a breaker fault occur.

c. Reclosure of a breaker that has tripped for some reason other than an initiation by the electrical protection logic may be performed if the cause of the trip is clearly understood and corrected prior to attempting reclosure, and if reclosure will not conflict with large motor starting restrictions.

d. Work on Main Generator and MPT protective relaying which can trip GCBs 4506 and 4510, should not be performed during Backfeed using MPTs & UATs.

e. IF Any Safety Related 4160V Bus is being supplied from the RAT (ERAT) when the respective RAT (ERAT) SVC is not in-service, THEN voltage monitoring shall be initiated per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet.

f. 4160V/6900V Bus configuration should be maintained on the listed Primary source unless transfer to the Secondary source is desired to support surveillance testing, maintenance activities, or as required due to degraded grid conditions.

RAT 'B' and ERAT are functionally equivalent in their ability to support 4160V Safety Bus power requirements.

Keep the Transmission Electric System Coordinator (Dispatcher) informed of changes in the lineup.

g. If an SVC fails to 'FREEZE' (5011-7G/8G) while transferring safety related busses, the bus transfer should be completed without delay, and the SVC investigated.

h. Each time a 4160V 1C1 (1E22-S004) Magne Blast Breaker is racked-in, the Plunger/Aux Switch Rod Contact Gap measurements shall be verified SAT per CPS 3515.01, Operation Of 6900/4160/480V Circuit Breakers.

i. If the DG 1A(1B)[1C] output breaker trips while the Div 1(2)[3] DG is the only supply to the 4160V Bus 1A1(1B1)[1C1], the 1A1(1B1)[1C1] bus will not automatically re-energize.

Due to the potential for the fault to adversely impact the off-site sources, the use of the Offsite Source Permissive push-button (only functions within 15 secs to allow the RAT/ERAT breaker to automatically close & re-energize the bus) shall not be used unless an in-use surveillance or test procedure specifically directs the use of this function.

j. Notify Ameren and the Power Team of any problems with Aux Power that will limit plant operation or capability. This includes, but is not limited to:

1) Any unplanned Diesel Generator unavailability

2) Any Static Var Compensator unavailability

3) Extended unplanned unavailability of any normal or reserve source to a 6.9KV or 4.16KV bus.

3. CPS 3502.01 – 480 VAC DISTRIBUTION PRECAUTIONS [.1.10]

   a. During Auxiliary Power System operation, all safety requirements in SA-AA-129, ELECTRICAL SAFETY should be observed.

   b. All breaker activities performed on OPERABLE switchgear shall be evaluated for SWITCHGEAR OPERABILITY/SEISMIC QUALIFICATION per CPS No. 1014.11, 6900/4160/480V SWITCHGEAR/ CIRCUIT BREAKER OPERABILITY PROGRAM.

      1) This includes, but is not limited to, opening the cubicle door and racking operations.

   c. When verifying breakers racked in, verify that the charging spring motor circuit is energized (on breakers that are so equipped).

   d. Prior to energizing the 480V Substation, careful consideration should be given to specific loads supplied from the Substation, especially those that may start, to prevent equipment damage and/or plant instability.

   e. Prior to de-energizing the 480V Bus all loads being de-energized should be considered and, if necessary, alternate components supplied from a different power source should be started. The applicable bus outage checklist should be consulted for plant conditions and precautions to be taken.

   f. If the two 480V Buses to be paralleled are energized from different sources, ensure there is < 5° phase angle difference between the two sources by checking across a 6.9KV/4.16V feeder breaker with the Sync Switch.

   g. Short duration paralleling is acceptable in the event it is desirable not to interrupt power to a 480V Bus. However, when two buses are paralleled, the available fault current is above the short circuit rating of the breakers. A fault occurring at this time would almost certainly cause breaker failure and equipment damage. Time spent in this condition should be kept to a minimum.

h. Maximum allowable amperage of the 480V bus pairs:

1) 480V Bus C & D: 112 amps

2) 480V Bus 1H & 1I: 112 amps

3) 480V Bus 1L & 1M: 84 amps

Monitor the ammeters of the 480V Buses that are paired. In the event the maximum allowable amperage is exceeded, reduce the overload condition by manually tripping unit heaters on the various MCCs supplied by the substation until the desired transformer load is obtained.

There are no amperage limitations defined for 480V buses O&P, and 1D&1E because the total load of the busses, when paired on a single unit substation transformer does not exceed the 100% KVA rating of the transformer.

Before attempting to restore systems following a power outage (i.e., Station Black Out or Bus Outage), ensure that power is available/restored to the radiation monitors prior to restoring power to the trip system logic. This is to avoid inadvertent actuations and/or isolations.

4. CPS 3502.01 – 480 VAC DISTRIBUTION LIMITATIONS **[.1.10]**

a. Refer to ITS 3.8.9 and 3.8.10 for Electrical Power Systems, AC Sources, Limiting Conditions for Operation.

b. Reclosure of a breaker that has tripped on thermal overload may be performed once.

c. Reclosure of a breaker that has tripped on other than thermal overload may be performed once, providing the following conditions are met:

1) Shift Management has given permission.

2) Reclosure can be done remotely to prevent hazard to personnel should a breaker fault occur.

3) Loss of component availability will cause a significant disruption of operational activities.

d. The preferred method for operation of locally controlled breakers is to use the remotely mounted handswitches for each of the 480V substation main feed breakers.

5. Refer to the following lesson plans for precautions and limitations applicable to the following auxiliary power related systems:

   a. N-CL-OPS-262004 (Switchyard)

   b. N-CL-OPS-264000 (Diesel Generator/ Diesel Fuel Oil)

6. SA-AA-129 (Electrical Safety) provides the safe work practices and proper personal protective equipment requirements to be used by all personnel at Exelon Nuclear facilities.

B. Transformer Cooling System Operations

1. Placing UAT Cooling in Service (CPS 3504.01 Section 8.1.11) — **[.1.11.1]**

   NOTE: With Mode Switches in AUTO, if UAT windings are 60°C - 70°C (140°F - 158°F), stage 1 fans will continue to run, above 70°C (158°F) both stage 1 and 2 fans will continue to run, and below 60°C (140°F), neither will continue to run.

   a. Perform CPS 3504.01E001 (MAIN POWER AND UNIT AUX TRANSFORMERS) electrical lineup to place each UAT cooling system in service.

   b. Verify all cooling fans running.

   c. Place following UAT switches to AUTO:

      1) UAT 1A - Cooler Stage 1.

      2) UAT 1A - Cooler Stage 2.

      3) UAT 1B - Cooler Stage 1.

      4) UAT 1B - Cooler Stage 2.

   d. Unless waived by NSED, start-up Serveron Monitor.

1) Open/verify open 1AP01EA(B)-TM8-1, UAT 1A(1B) - Serveron Oil Supply Valve.

2) Open/verify open 1AP01EA(B)-TM8-4, UAT 1A(1B) - Serveron Oil Return Valve.

3) In the Serveron Monitor cabinet (upper right hand corner) place the Power switch to ON.

a) The monitor will take 2 - 3 hours to thermally stabilize, after which it will make the next scheduled sample run.

2. UAT Cooling System Shutdown (CPS 3504.01 Section 8.1.13) [.1.11.2]

a. Place following UAT switches to OFF:

1) UAT 1A - Cooler Stage 1.

2) 2) UAT 1A - Cooler Stage 2.

3) 3) UAT 1B - Cooler Stage 1.

4) 4) UAT 1B - Cooler Stage 2.

b. Unless waived by NSED, secure the Serveron Monitor:

1) In the Serveron Monitor cabinet (upper right hand corner) place the Power switch to OFF.

2) Shut 1AP01EA(B)-TM8-1, UAT 1A(1B) - Serveron Oil Supply Valve.

3) Shut 1AP01EA(B)-TM8-4, UAT 1A(1B) - Serveron Oil Return Valve.

3. UAT Degraded Cooling System Response (CPS 3504.01 Section 8.3.2) [.1.11.3]

a. IF UAT cooling is reduced THEN perform the following:

1) Monitor transformer operating parameters (loading, winding/liquid temp, control panel, etc.).

2) Attempt to restore cooling.

b. Observe UAT loading guidelines and temperature limits as specified in CPS 3504.01 (MAIN POWER AND

UNIT AUXILIARY TRANSFORMERS COOLING), Table 3.

NOTE: UAT temperature limits are not expected to be exceeded if the loading guidelines in Table 3 are observed. Exceeding the loading guidelines requires more frequent monitoring for temperature. Exceeding any temperature limit requires action to reduce the temperature to avoid transformer damage. Consider implementing alternate cooling (water sprays, blowers).

c. IF Any UAT temperature exceeds the temperature limit in Table 3, THEN reduce load on the affected UAT.

C. Energizing / De-Energizing High Voltage Buses

1. De-energizing 4160v Bus 1A1,(1B1), [1C1] (CPS 3501.01 Section 8.1.6)

[.1.11.4]

a. Complete CPS 3514.01C005 (C006) [C007], 4160V Bus 1A1 (1AP07E) (1B1 (1AP09E)) [1C1 (1E22-S004)] Outage Checklist (omit this step if rapid bus de-energization is required).

- **Controlling Plant Evolutions Precisely**

b. Place/verify the control switch for the sources not supplying 4160V Bus 1A1 (1B1) [1C1] to PULL-TO-LOCK.

1) 4160V Bus 1A1 (1B1) [1C1] Res Bkr, 1AP07EH (1AP09EC) [1ETR4C1], OR

2) DG 1A (1B) [1C] Output Bkr, 1AP07EC (1AP09EH) [1E22-S001], OR

3) 4160V Bus 1A1 (1B1) [1C1] Mn Bkr, 1AP07EK (1AP09EA) [1RT4C1]

c. Place the control switch for the source supplying 4160V Bus 1A1 (1B1) [1C1] to PULL-TO-LOCK.

1) 4160V Bus 1A1 (1B1) [1C1] Mn Bkr, 1AP07EK (1AP09EA) [1RT4C1], OR

2) 4160V Bus 1A1 (1B1) [1C1] Res Bkr, 1AP07EH (1AP09EC) [1ETR4C1], OR

3) DG 1A (1B) [1C] Output Bkr, 1AP07EC (1AP09EH) [1E22-S001]

2. De-energizing 4160v Bus 1A, (1B) (CPS 3501.01 Section 8.1.5) **[.1.11.5]**

   a. Complete CPS 3514.01C003 (C004), 4160V Bus 1A (1AP06E) (1B (1AP08E)) Outage Checklist (omit this step if rapid bus de-energization is required).

   b. Place/verify the control switch for the source not supplying 4160V Bus 1A (1B) to PULL-TO-LOCK.

      1) 4160V Bus 1A (1B) Res Bkr, 1AP06EM (1AP08EG)

      OR

      2) 4160V Bus 1A (1B) Mn Bkr, 1AP06EK (1AP08EJ)

   c. Place the control switch for the source supplying 4160V Bus 1A (1B) to PULL-TO-LOCK.

      1) 4160V Bus 1A (1B) Mn Bkr, 1AP06EK (1AP08EJ)

      OR

      2) 4160V Bus 1A (1B) Res Bkr, 1AP06EM (1AP08EG)

3. De-energizing 6900v Bus 1A, (1B) (CPS 3501.01 Section 8.1.4) **[.1.11.5]**

   a. Complete CPS 3514.01C001 (C002), 6900V Bus 1A (1AP04E) ((1B)(1AP05E)) Outage Checklist (omit this step if rapid bus de-energization is required).

   b. Place/verify the control switch for the source not supplying 6900V Bus 1A (1B) to PULL-TO-LOCK.

      1) 6900V Bus 1A (1B) Res Bkr, 1AP04EF (1AP05EE)

      OR

      2) 6900V Bus 1A (1B) Mn Bkr, 1AP04EC (1AP05EH)

   c. Place the control switch for the source supplying 6900V Bus 1A (1B) to PULL-TO-LOCK.

4. Energizing 4160v Bus 1A1, (1B1), [1C1] (CPS 3501.01 Section 8.1.3)

[.1.11.6]

NOTE: Prior to energizing 1AP07E (1AP09E) [1E22-S004], refer to CPS 3514.01C005 (C006), [C007], 4160V Bus 1A1 1AP07E (1B1 (1AP09E)) [1C1 (1E22-S004)] Outage checklist.

The NOT AVAILABLE 4160V BUS BREAKER annunciator (Div 1 & 2 only) will not be reset in the following step if one of the power sources to the bus is unavailable.

Steps applicable to component restoration that is not available for restoration per its controlling document may be skipped.

Only RAT 'B' and the ERAT are serviced by a SVC. Where "RAT SVC" appears, this refers to RAT 'B' SVC.

a. Prior to energizing the bus, Place/verify all feeds to the applicable 4160V Bus 1A1 (1B1) [1C1] in the PULL-TO-LOCK position.

   1) 4160V Bus 1A1 (1B1) [1C1] Mn Bkr, 1AP07EK (1AP09EA) [1RT4C1]

   2) 4160V Bus 1A1 (1B1) [1C1] Res Bkr 1AP07EH (1AP09EC) [1ETR4C1]

   3) 4160V Bus 1A1 (1B1) [1C1] DG Bkr 1AP07EC (1AP09EH) [1E22-S001]

b. IF any Safety Related 4160V Bus is being supplied from the RAT (ERAT) when the respective RAT (ERAT) SVC is not in-service, THEN voltage monitoring shall be initiated per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet.

c. Verify open/open the following breakers per CPS 3502.01, 480VAC Distribution (as applicable):

   1) 480V XFMR 1A & A1 BKR, 1AP07EJ

   2) (480V XFMR 1B & B1 BKR, 1AP09EB)

   3) [480V Transformer 1C Bkr (at 4160V Bus 1C1 Cub 5)]

d. Verify/place SSW Pump 1A (1B) [1C], 1SX01PA(B)[C] control switch in PULL-TO-LOCK.

e. Remove/verify removed the control power fuses or the breakers racked out for the following loads (as applicable):

This breaker activity requires a review of CPS 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program requirements.

1) 1A1: LPCS Pump, 1E21-C001 and RHR A Pump, 1E12-C002A

2) (1B1: RHR B Pump, 1E12-C002B and RHR C Pump, 1E12-C002C)

3) [1C1: HPCS Pump, 1E22-C001 (at 4160 Bus 1C1 Cub 4)]

f. Place 4160V Bus 1A1 (1B1) [1C1] Mn {Res} Bkr Sync to ON.

g. Verify 4160V Bus 1A1 (1B1) [1C1] Incoming Voltage is between 3950 to 4300 volts (Low: 5008-5L setpoint; High: Operability Limit). Adjust Incoming Voltage within allowable OPERABILITY range, if necessary.

h. Close 4160V Bus 1A1 (1B1) [1C1] Mn {Res} Bkr, 1AP07EK {1AP07EH} (1AP09EA {1AP09EC}) [1RT4C1 {1ETR4C1}].

i. Verify 4160V Bus 1A1 (1B1) [1C1] is energized.

j. Place 4160V Bus 1A1 (1B1) [1C1] Mn {Res} Bkr Sync to OFF.

k. If available, place the 4160V Bus 1A1 (1B1) [1C1] Res {Mn} Bkr, 1AP07EH {1AP07EK} (1AP09EC {1AP09EA}) [1ETR4C1 {1RT4C1}] control switch to AUTO.

l. If available, place DG 1A (1B) [1C] Output Bkr, 1AP07EC (1AP09EH) [1E22-C001] C/S to AUTO.

m. 480V Unit Subs [480V Transformer 1C] may be energized per CPS 3502.01, 480VAC Distribution.

[.1.11.7]

5. Energizing 4160v Bus 1A, (1B) (CPS 3501.01 Section 8.1.2)

   NOTE: Prior to energizing 1AP06E (1AP08E), refer to CPS 3514.01C003 (C004), 4160V Bus 1A (1AP06E) (1B (1AP08E)) Outage checklist.

   Steps applicable to restoration of a component that is not available for restoration per its controlling document may be skipped.

   a. Prior to energizing the bus, place/verify all feeds to the 4160 Bus 1A (1B) in the PULL-TO-LOCK position.

      1) 4160V Bus 1A (1B) Mn Bkr, 1AP06EK (1AP08EJ)

      2) 4160V Bus 1A (1B) Res Bkr, 1AP06EM (1AP08EG)

   b. Verify open/open the following breakers (as applicable) per CPS 3502.01, 480VAC Distribution:

      1) 480V XFMR Q & I BKR, 1AP06EJ (480V XFMR J & R BKR, 1AP08ED)

      2) 480V XFMR G & K BKR, 1AP06EQ (480V XFMR H & L BKR, 1AP08EK)

   c. Verify/place the following C/S's in PULL-TO-LOCK:

      1) For 4160V Bus 1A:

         a) Service Air Compressor 0, 0SA01C

         b) PSW Pump 1A, 1WS01PA

         c) PSW Pump 1C, 1WS01PC

         d) CCW Pump 1A, 1CC01PA

         e) CCW Pump 1C, 1CC01PC

      2) For 4160V Bus 1B:

         a) Service Air Compressor 1, 1SA01C

         b) Service Air Compressor 2, 2SA01C

         c) PSW Pump 1B, 1WS01PB

         d) CCW Pump 1B, 1CC01PB

d. As applicable, place the following pumps in LOCK/STOP:

a) Cond Booster Pump A (B), 1CB01PA(B)

b) Cond Booster Pump 1A (B) Aux Lube Oil Pmp, 1CB07PA(B)

c) Cond Booster Pump C (D), 1CB01PC(D)

d) Cond Booster Pump 1C (D) Aux Lube Oil Pmp, 1CB07PC(D)

e) Cond Pump A (B), 1CD01PA(B)

f) Cond Pump C (D), 1CD01PC(D)

e. Place 4160V Bus 1A (1B) Res {Mn} Bkr Sync to ON.

f. Close 4160V Bus 1A (1B) Res {Mn} Bkr, 1AP06EM {1AP06EK} (1AP08EG {1AP08EJ}).

g. Verify 4160 Bus 1A (1B) energized.

h. Place 4160V Bus 1A (1B) Res {Mn} Bkr Sync to OFF.

i. If available, place the 4160V Bus 1A (1B) Mn {Res} Bkr, 1AP06EK {1AP06EM} (1AP08EJ {1AP08EG}) C/S to AUTO.

j. 480V Unit Subs may be energized per CPS 3502.01, 480VAC Distribution.

6. Energizing 6900v Bus 1A (1B) (CPS 3501.01 Section 8.1.1) **[.1.11.7]**

NOTE: Prior to energizing 1AP04E (1AP05E), refer to CPS 3514.01C001 (C002), 6900V Bus 1A (1AP04E) (1B 1AP05E)) Outage checklist.

Steps applicable to restoration of a component that is not available for restoration per its controlling document may be skipped.

a. Prior to energizing the bus, place/verify all feeds to the 6900 Bus 1A(1B) in the PULL-TO-LOCK position.

1) 6900V Bus 1A (1B) Mn Bkr 1AP04EC (1AP05EH)

2) 6900V Bus 1A (1B) Res Bkr 1AP04EF (1AP05EE)

b. [6900V Bus 1B (1AP05E) only] Lock out the MDRFP to prevent auto start when the bus is reenergized.

c. On 1H13-P870, verify open/open the following breakers per CPS 3502.01, 480VAC Distribution (as applicable):

1) 480V XFMR 1F & 1J BKR, 1AP04EH (480V XFMR 1G & 1K BKR, 1AP05EC)

2) 480V XFMR 1L & 1D BKR, 1AP04EJ (480V XFMR 1E & 1M BKR, 1AP05EB)

3) 480V XFMR 1H BKR, 1AP04EG (480V XFMR 1I BKR, 1AP05EK)

4) 480V XFMR C & O BKR, 1AP04EA (480V XFMR P & D BKR, 1AP05ED

5) 480V XFMR M & E BKR, 1AP04EK (480V XFMR F & N BKR, 1AP05EG)

d. Place 6900V Bus 1A (1B) Res {Mn} Bkr Sync to ON.

e. Close 6900V Bus 1A (1B) Res {Mn} Bkr, 1AP04EF {1AP04EC} (1AP05EE {1AP05EH}).

f. Verify 6900V Bus 1A (1B) is energized.

g. Place 6900V Bus 1A (1B) Res {Mn} Bkr Sync to OFF.

h. If available, place the 6900V Bus 1A (1B) Mn {Res} Bkr, 1AP04EC {1AP04EF} (1AP05EH {1AP05EE}) C/S to AUTO.

i. 480V Unit Subs may be energized per CPS 3502.01, 480VAC Distribution.

D. Transferring High Voltage Buses

1. Transferring a 6900V or 4160V Bus TO or FROM its Reserve {Main} Source (CPS 3501.01 Section 8.1.8) **[.1.11.8]**

CAUTION: Main Generator Output voltage shall be > 21,560 volts prior to transferring 6.9KV busses or 4160V busses to the RAT. Voltages < 21,560 volts will under-voltage some BOP equipment.

NOTE: Transferring a 6900V or 4160V bus TO or FROM its Reserve (Main) Source should be monitored using BOTH computer points (AP-BA501 thru AP-BA520, and AP-BA536, APBA541, AP-BA542) and Control Board Meters to provide proper load shift indication.

a. IF Any Safety Related 4160V Bus is being supplied from the RAT (ERAT) when the respective RAT (ERAT) SVC is not in-service, THEN voltage monitoring shall be initiated per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet.

b. Place the Bus Res {Mn} Bkr Sync keylock switch to the ON position.

c. For 4160V Safety Related Bus 1A1 (1B1) [1C1] transfer: As time and resources permit, prior to transfer, attempt to adjust 4160V Bus Incoming Voltage within 4084 - 4300V.

NOTE: For all postulated 345 KV grid conditions, manual transfer of buses during high voltage conditions from RAT to ERAT, or vice-versa, can be performed with SVC out of service regardless of the difference in voltage between the two offsite sources of power. Transferring buses between the RAT and UATs will effect indicated MWe net and may require adjusting power or contacting the Power Team to adjust generation profile.

d. Verify the synchroscope is steady at ~ the 12 o'clock position. IF Synchroscope is NOT at ~ 12 o'clock position when closing the Main Source Feed Breaker, THEN verify:

1) The UAT's are fed in a backfeed lineup.

2) Cause of the synch switch indication is known.

3) SMngt permission is given for paralleling without normal synch scope indication.

NOTE: A stationary synchroscope at a position other than ~ 12 o'clock indicates the Reserve {Main} source is not energized.

e. Close the Bus Res {Mn} Bkr, and prior to releasing the switch to the AUTO position, verify:

1) Closed indication on the SOURCE breaker, and

2) A load shift is indicated on the bus load meters.

IF SOURCE breaker failed to close, OR a bus load shift is not indicated on the bus, THEN place the sync switch to OFF prior to releasing the switch to the AUTO position. This prevents the auto trip of the load breaker and the resulting loss of the bus.

IF OFF-GOING breaker failed to trip, THEN manually open the OFF-GOING breaker.

IF OFF-GOING breaker still fails to trip, THEN:

a) Verify both feed breakers are closed.

b) Using the breaker's handswitch, reclose the 'OFF-GOING' breaker.

c) Verify tripped/open the 'SOURCE' breaker when the 'OFF-GOING' breaker is returned to AUTO.

f. Place Handswitch for the tripped breaker to OPEN, and match the Flag with the indication on the tripped breaker in order to clear the AUTO TRIP Annunciator.

g. Place the Bus Res {Mn} Bkr Sync keylock switch to OFF.

h. Notify CMO Group to perform thermography on Circuit Switcher 4538 (RATs) & B018 (ERAT) if transformer assumed any significant loading.

2. Transferring a 4160V Bus TO or FROM the DG (CPS 3501.01 Section 8.1.7)

E. Abnormal Voltage

1. High Voltage 4160V Safety Bus Response (SAFETY RELATED 4.16KV BUS HIGH VOLTAGE – Annunciator 5007-5M) (CPS 3501.01 Section 8.3.4) [.1.11.9]

a. IF 4.16KV Bus 1A1 (1AP07E), 1B1 (1AP09E), or 1C1 (1E22-S004) voltage exceeds 4300V THEN take required action (below) as indicated in table below (note that time zero shall be established from the point of exceeding 4300V as determined from plant indications/ recorders):

Voltage	Required Actions
> 4300V and ≤ 4454V for ≤ 30 minutes	1) only
> 4300V for > 30 minute (INOPERABLE)	1), 2), 3), 4)
> 4454V (INOPERABLE)	1), 2), 3), 4)

1) Restore bus voltage to < 4300V. This is required within 30 minutes to maintain OPERABILITY.

2) Declare the affected divisional electrical distribution subsystem(s) INOPERABLE. Refer to ITS LCO 3.8.9/10.

3) NSED perform an 'operability evaluation' or 'engineering evaluation' prior to the affected divisional electrical distribution subsystems being declared OPERABLE since the system has exceeded analyzed limits.

b. Perform CPS 9082.02, Electrical Distribution Verification for the affected ITS SR 3.8.9.1/3.8.10.1 divisional electrical distribution subsystems when < 4300V in order to support re-establishing OPERABILITY.

c. Additional actions required by CPS 3501.01 (HIGH VOLTAGE AUXILIARY POWER SYSTEM)

1) Initiate voltage monitoring per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet under the following conditions:

   a) Any Safety Related 4160V Bus is being supplied from the RAT (ERAT) when the respective RAT (ERAT) SVC is not in-service.

   b) When annunciator 5007-5M, 4KV BUS HIGH VOLTAGE is in an alarm condition, or is out-of-service.

2) Maintain and/or restore bus voltage to 4136 - 4251 V (5007-5M/5008-5L setpoints) using any available/applicable method below:

a) Placing RAT (ERAT) SVC in-service per CPS 3505.03 RAT & ERAT Static Var Compensator (SVC).

b) Increasing the RAT 'B' 4160V loading by placing additional 4160V BOP loads on the RAT 'B'.

c) Transferring loads to the alternate offsite source ERAT (RAT 'B').

d) Manually adjusting the ERAT-LTC Tap setting per CPS 3505.01, 345 & 138KV Switchyard (SY).

e) Lowering TG (DG) generator output voltage.

f) Requesting Electric Supply Dispatcher to lower 138KV/345KV line voltage.

g) Transferring the bus(es) to the DG. Transferring the bus(es) to the DG(s) should be done only when all other methods of controlling voltage have been exhausted, and when bus voltage is expected to significantly exceed 4454 volts or failure of safety related loads are imminent.

3) As necessary, assign computer points SY-DA501/2 (345KV support) and/or AP-BA525/530/535 (138KV support) to annunciator 5009-3H, PMS ALARM DISPLAY per CPS 3512.01 (DCS/CX & PMS/CZ) to act as an annunciator backup.

2. Low Voltage 4160V Safety Bus Response (SAFETY RELATED 4.16KV BUS LOW VOLTAGE – Annunciator 5008-5L) (CPS 3501.01 Section 8.3.1) **[.1.11.10]**

a. If Safety related buss voltage is < 4000 V then cause an auto transfer to alternate source by placing the appropriate RAT/ERAT feed breaker for the associated bus in Pull-to-Lock (Hard Card P870).

b. Initiate voltage monitoring per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet under the following conditions:

1) Any Safety Related 4160V Bus is being supplied from RAT B (ERAT) when the respective RAT (ERAT) SVC is not in-service.

2) When annunciator 5008-5L is in an alarm condition, or when this annunciator is out-of-service.

c. Additional actions required by CPS 3501.01 (HIGH VOLTAGE AUXILIARY POWER SYSTEM)

NOTE: Safety Related 4160V buses are analyzed for sustained operation as low as the secondary under voltage relay automatic DG start/bus tie in setpoint [≥ 4051 V & ≤ 4092 V (nominal 4072 V)].

The bus(es) shall be declared INOP when bus voltage is < 4084 V.

Only RAT 'B' & the ERAT are serviced by a SVC. Where "RAT SVC" appears, this refers to RAT 'B'.

1) Initiate voltage monitoring per CPS 3501.01D001, Monitoring Safety Related 4.16KV Bus Voltage Data Sheet under the following conditions:

a) Any Safety Related 4160V Bus is being supplied from the RAT (ERAT) when the respective RAT (ERAT) SVC is not in-service.

b) When annunciator 5008-5L, 4KV BUS LOW VOLTAGE is in an alarm condition, or is out-of-service.

2) Maintain or restore bus voltage to 4136 - 4251 V (5007-5M/5008-5L setpoints) using any available/ applicable method below:

a) Placing RAT (ERAT) SVC in-service per CPS 3505.03, RAT & ERAT Static Var Compensator (SVC).

b) Reducing BOP auxiliary loads on RAT 'B'.

c) Transferring loads to the alternate offsite source ERAT (RAT 'B').

d) Manually adjusting the ERAT-LTC Tap setting per CPS 3505.01, 345 & 138KV Switchyard (SY).

e) Raising TG (DG) generator output voltage.

f) Requesting Electric Supply Dispatcher to raise grid voltage.

3) As necessary, assign computer points SY-DA501/2 (345KV support) and/or AP-BA525/530/535 (138KV support) to annunciator 5009-3H, PMS ALARM DISPLAY per CPS 3512.01 (DCS/CX & PMS/CZ) to act as an annunciator backup.

F. Paralleling Class 1E 4.16KV Bus With Respective DG

1. DG – Offsite Power Parallel Operation

[.1.11.11]

NOTE: This section discusses procedure for the Division 1 DG (DG 1A) only. Paralleling operations for the Division 2 & 3 DGs are similar.

CAUTION: Only one Diesel Generator is to be paralleled with offsite power at any one time, and then only for, 1) approved testing; 2) response to HIGH VOLTAGE on safety related 4160V busses; or 3) returning a bus to off-site power following recovery from the loss of both the Main and Reserve supplies. The time a DG is paralleled with off site power should be minimized to ensure the DG is available for emergencies.

Starting of DGs is allowed with lube oil temperature as low as 85°F, without damage occurring to the engine. However, the generator should not be loaded with a lube oil temperature less than 110°F.

a. Start DG 1A and make it ready for loading.

b. Lineup off-site power to safety related 4160V Buses as follows:

1) IF It is desired to parallel the DG with RAT 'B', THEN transfer/verify 4160V Bus 1A1 to/on RAT 'B'.

2) IF the diesel generator is going to be paralleled with RAT 'B' AND switchyard breaker 4502 or 4522 is open, THEN turn OFF the auto recloser for the other breaker (i.e., 4522 or 4502).

3) IF it is undesirable to parallel the DG with RAT 'B', THEN transfer/verify 4160V Bus 1A1 to/on the ERAT.

CAUTION: If RAT 'B' is not available, the Diesel Generators should not be paralleled with the ERAT, since turning off the reclosing relays reduces the reliability of the 138 KV source, precisely when it is needed the most. Under these conditions a fault could result in the loss of the 138 KV source as well as any safety related busses supplied by that source.

4) Inform the Electrical Supply Supervisor that the reclosing relays for breaker 1372, at the South Bloomington Substation, and breaker 1372, at Clinton Route 54 Substation, shall be turned off.

c. Place DG 1A Output BKR SYNC switch to ON position.

d. Adjust DG 1A Incoming voltage with DG 1A Generator Voltage Regulator control switch so that Incoming voltage is matched with Running voltage.

e. Adjust DG 1A speed with DG 1A Governor control switch such that DG frequency is slightly greater than bus frequency as indicated by the following:

1) CLOCKWISE rotation of the synchroscope at a speed of approximately one revolution every 60-120 sec (i.e., ½ – 1 RPM) or slower.

2) Both synchroscope lights are extinguished at the 12 o'clock position.

3) Both synchroscope lights are brightly lit at the 6 o'clock position.

f. WHEN the synchroscope's pointer nears the vertical (12 o'clock) position, and the synchronizing lamps go dark then:

1) Close DG 1A Output Bkr.

2) Promptly load DG 1A to at least 100 - 200 KW.

3) Verify VARs between -500 and +500 KVAR and adjust as necessary.

g. Gradually load DG 1A at a rate of approximately 1000 KW per minute to the desired load with DG 1A Governor control switch.

h. Maintain VARs within the limits of the DG 1A REACTIVE LOAD CAPABILITY CURVE using the DG 1A Voltage Regulator control switch.

CAUTION: To ensure operability and to prevent overloading of the Emergency Diesel Generators, the Continuous Load Rating of 3869 KW should not be exceeded, except as directed by approved surveillance tests.

G. DC Control Power Operations

1. DC FAILURE 4.16 KV BUS 1A (1B)) – ARP 5012-1C

[.1.11.12]

a. Refer to CPS 4201.01 (Loss of DC Power) to determine possible causes and impact of a loss of DC power.

b. Check control power supplies for Bus 1A and 1B (see table below):

	Bus 1A	**Bus 1B**
Main Power Supply	DC MCC 1E Ckt #1	DC MCC 1F Ckt #1
Main Power Supply Fuse (100 amp fuse)	Cubicle 1AP06EH	Cubicle 1AP08EC
Undervoltage Relay Power Supply Fuse (6 amp fuse)	Cubicle 1AP06EK	Cubicle 1AP08EJ

c. Transfer Service Air Compressors to a bus that has control power to it prior to swapping control power supplies to a bus.

d. At the 4160V Bus, remove the 100 amp DC fuse holder with fuses from the Main {Reserve} box and insert them in the Reserve {Main} box.

1) This breaker activity requires a review of CPS 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program requirements.

e. DC Control Power to the bus can be verified in the MCR by checking breaker indications for the bus and verifying that the DC FAILURE 4160V BUS annunciator is clear for the affected bus.

2. DC FAILURE 6.9 KV BUS 1A (1B)) – ARP 5011-1E

[.1.11.12]

   a. Refer to CPS 4201.01 (Loss of DC Power) to determine possible causes and impact of a loss of DC power.

   b. If alarm is due to loss of DC control power, attempt to restore DC control power to the 6900V bus using either:

      1) Cross tie DC MCC 1E/1F per CPS No. 3503.01, BATTERY AND DC DISTRIBUTION (DC), Cross-Connecting Distribution Panels 1E and 1F section, OR

      2) Transfer 125VDC Main Supply fuses to Reserve Supply source per CPS No. 3501.01:

         a) Transfer Circulating Water Pumps to a bus that has control power to it prior to swapping control power supplies to a bus.

         b) At the 6900V Bus, remove the 100 amp DC fuse holder with fuses from the Main {Reserve} box and insert them in the Reserve {Main} box.

            (1) This breaker activity requires a review of CPS 1014.11, 6900/4160/480V Switchgear/Circuit Breaker Operability Program requirements.

            (2) DC Control Power to the bus can be verified in the MCR by checking breaker indications for the bus and verifying that the DC FAILURE 6900 BUS annunciator is clear for the affected bus.

3. Notes, cautions & warnings when swapping DC control power fuses (common to 4.16 & 6.9KV buses):

   - All breakers which lose status light indication also lose trip power and can only be tripped manually.

- On a loss of control power to a Class 1E Bus, transferring control power fuses may not provide power to the bus for control power since the reserve supply is fed from the same 125VDC MCC as the main supply.

- Transferring of 125VDC for bus control power from Main {Reserve} to Reserve {Main} on a 4160V Bus with a Service Air Compressor running will cause the compressor breaker to trip open upon re-inserting the control power fuses.

- Do not swap bus control power fuses on a 6900V Bus with a Circulating Water Pump running. Removal of bus control power fuses may result in personnel injury and damage to the motor due to excessive overcurrent (motor is normally synchronous operation).

H. Backfeed Using MPTs and UATs (CPS 3501.01 Section 8.2.1 and 3501.01 C001)

1. Establishing Backfeed Using MPTs & UATs

[.1.11.13]

NOTES:

- Portions of this evolution will be performed by qualified electrical technicians.

- Whenever possible, minimize the time interval between taking the plant off-line and initiating the MPT Backfeed since residual magnetic flux present in the MPTs will serve to lower the in-rush current during the backfeed energization.

a. Coordinate with AMEREN/TSO to verify 345 KV Switchyard/Grid are stable and capable of supporting a split bus alignment [i.e., North & South busses separated via either GCB 4518 (preferred), 4522 or 4502 being open.] This will allow the MPT backfeed to be initiated from one bus while the other bus continues to feed the RATs, thereby isolating the RATs from the backfeed harmonics as much as practical. Grid and weather conditions shall be considered since this will reduce the sources feeding the RATs and introduce other risk factors. Note that operation of the Switchyard 345KV breakers are controlled via Switching Orders.

IF AMEREN/TSO determines that separating the switchyard busses is impractical or deemed insufficient

THEN Coordinate with AMEREN/TSO to verify 345 KV Switchyard/Grid are stable and capable of supporting the SVCs out-of-service and then remove the RAT and ERAT SVCs from service and enter the applicable LCOs.

b. Per CPS 3505.01, 345 & 138KV Switchyard (SY), open applicable GCB 4518 (preferred), 4522 or 4502. (Only applicable if the switchyard/grid is stable and capable of supporting a split bus configuration).

c. As necessary, transfer 4160V safety busses (1A1 & 1B1) to either RAT 'B' or the ERAT depending on AMEREN/ TSO Grid Evaluation/Recommendations.

d. Ensure 4160V safety bus 1C1 is aligned to RAT 'B'.

e. Prepare, approve and install a Tracking Purposes Temporary Configuration Change (TCC) to disable reverse power relays (this allows backfeed through the MPTs & UATs).

f. Shutdown the Isolated Phase Bus Duct Cooling System.

g. Install safety grounds in the PT Cubicle (Turbine Building 767') for all three Main Generator phases (A, B, & C) and the lines between 4508 & the MPTs in the Switchyard.

h. Remove the Generator to Isolated Phase Bus Duct Links (Phase A, B, and C).

i. Remove the safety grounds in the PT Cubicle (Turbine Building 767') for all three Main Generator phases (A, B, & C) and the lines between 4508 & the MPTs in the Switchyard.

j. IF Required per SMngt, THEN start Isolated Phase Bus Duct Cooling System.

k. Verify MPT cooling in service.

l. Reset/verify reset generator lockout relays. IF the relays are found to be tripped THEN with SMngt concurrence, reset the relays.

m. Verify power to the MPT and UAT protective relaying by verifying key annunciators are reset.

n. Hang Information Tag on MCR switches GCB 4506 & 4510 stating that the Generator Backfeed lineup is in effect.

o. Open/verify open GCB 4510 and GCB 4506.

p. Close Motor Operated Disconnect 4508.

q. Close applicable GCBs 4510 and/or 4506 using local control from the Relay House. Align MCR switches to 'After/Close' to reflect breaker status. Note that GCB 4510 is the preferred first tie-in when GCB 4518 or 4522 is open and GCB 4506 is the preferred first tie-in when GCB 4502 is open.

r. As desired, transfer power supplies to 4160V and 6900V Buses 1A and 1B from their Reserve Source's (RATs) to their Main Source (UATs).

s. As necessary, transfer 4160V safety busses (1A1, 1B1 & 1C1) to either RAT 'B' or the ERAT depending on AMEREN/ TSO Grid Evaluation/Recommendations.

t. As necessary, restore RAT and ERAT SVCs to service.

u. Evaluate operability of offsite sources per ITS and exit LCOs if possible.

2. Restoring From Backfeed — **[.1.11.13]**

a. Transfer power supplies to 4160V and 6900V Buses 1A and 1B from their Main Source (UATs) to their Reserve Sources (RATs).

b. Open/verify open GCB 4510, GCB 4506, and Motor Operated Disconnect 4508 from the MCR.

c. Shutdown/verify shutdown the Isolated Phase Bus Duct Cooling System.

d. Re-enable the reverse power relays which were previously disabled to support backfeed.

e. Install safety grounds in the PT Cubicle (Turbine Building 767') for all three Main Generator phases (A, B, & C) and the lines between 4508 & the MPTs in the Switchyard.

f. Re-Install the Generator to Isolated Phase Bus Duct Links (Phase A, B, and C).

g. Remove the safety grounds in the PT Cubicle (Turbine Building 767') for all three Main Generator phases (A, B, & C) and the lines between 4508 & the MPTs in the Switchyard.

h. Restore the 345KV Switchyard to the shutdown normal configuration (without Generator Backfeed).

i. Align the 4160V Safety Busses 1A1, 1B1, and 1C1 as appropriate for shutdown plant conditions.

X. Operating Experience (OPEX)

Optional Student Exercise #1

See Attachment M. Given CPS operating experience associated with PT fuse removal causing a de-energizing of 4160 Volt Bus 1A1, describe the lessons learned to prevent similar occurrences in accordance with the training materials and applicable procedures. Try to come up with at least one HU tool, performance, or behavior that could have prevented the event.

1.
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2.
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Optional Student Exercise #2

See Attachments N, N.1 & N.2. Given operating experience from the H.B. Robinson event associated with electrical equipment failures and inappropriate operator actions, describe the lessons learned to prevent similar occurrences in accordance with the training materials and applicable procedures. Include the following:

- A review of common deficiencies identified in SOER 10-02 (Engaged, Thinking Organizations) which tie in to the H. B. Robinson event.
- Come up with at least two HU tool, performance, or behavior fundamentals that could have greatly minimized the severity of the first electrical fault event then come up with two other fundamentals that could have prevented the second electrical fault event.
- What defenses do we have in place here at CPS to help prevent a similar occurrence related to the Auxiliary Power System?

1.
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2.
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3.
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Optional Student Exercise #3

NRC IN 2012-03 - DESIGN VULNERABILITY IN ELECTRIC POWER SYSTEM (BYRON EVENT)

- Read OPEX in Attachment O.
- Be ready to discuss auxiliary power protection scheme vulnerability which was discovered during and following the event.
- How does our CPS degraded / loss of voltage protection scheme compare?
- What MCR actions are currently in place at CPS to help compensate for this vulnerability?

Optional Student Exercise #4

CPS LER 2012-001-00 LOSS OF SECONDARY CONTAINMENT DIFFERENTIAL PRESSURE DUE TO TRANSFORMER TRIP

- Read OPEX in Attachment P.1.
- Be ready to discuss the auxiliary power protection scheme latent design error which was discovered during and following the event.
- In terms of potential plant impact, what is the difference between a slow (vice fast) transfer of divisional power to its reserve source?

Optional Student Exercise #5

CPS LER 2013-008-00 FAILURE OF DIV 1 TRANSFORMER LEADS TO ISOLATION OF INSTRUMENT AIR TO CONTAINMENT AND MANUAL REACTOR SCRAM

- Read OPEX in Attachment P.2.
- Discuss the immediate impact of trip of the 4160V 1A1 breaker to include substations lost and associated loads.
- Discuss operator actions which were required to help ensure a safe (and uncomplicated) plant shutdown.
- What means were used to ensure all control rods fully inserted?

Optional Student Exercise #6

Browns Ferry Unit 2 - ICES #311418 – (HU Event)
Inadvertent Trip of Condensate Booster Pump

- Read OPEX in Attachment P.3.
- What human performance (HU) errors were made?
- What were contributing factors to the event (emphasize flawed HU performance)?
- Discuss the immediate impact of the trip of the 2B Condensate Booster Pump.
- What are the lessons learned?

Optional Student Exercise #7

CPS LER 2017-002-00 FAILURE OF DIV 1 DG VENT FAN LOAD SEQUENCE RELAY CIRCUIT DURING CONCURRENT MAINTENANCE OF RHR DIV 2 RESULTS IN UNANALYZED CONDITION

- Read OPEX in Attachment P.4.
- What human performance (HU) techniques would have prevented or mitigated the event?
- What were the potential consequences of operating the plant in this condition?
- What are the lessons learned?

XI. Conclusion/Lesson Summary

A. Major Flow Paths

From this presentation you should be able to recall the overall configuration of the Auxiliary Power System from the various offsite sources down to the 480VDistribution Systems.

1. You should be able to trace the flow of power from the onsite generators and offsite source transformers through the Non-segregated Bus Ducting to each of the Class 1E and Non-Class 1E Buses.

2. The ability to describe the flow paths including configuration of the various 480Vdistribution systems.

B. Controls, Interlocks and Operations

1. Knowledge needed to support in plant training on the Auxiliary Power System Transformers and associated cooling systems was addressed in this lesson. This included the indications, controls and operation of the transformer equipment.

2. The lesson detailed the “S” and “F” protection logic for the source transformers and Non-segregated Buses. You should be able to recall the types of trip signals provided, linkage through the Kirk Key Disconnects and the automatic actions that result from actuation of the protective circuits.

3. From the knowledge gained in this lesson and applicable procedures you should be able to monitor automatic actions in the Auxiliary Power System and perform the manual transfer of power sources for each of the 6.9 KV, 4.16 KV, and 480V Buses. These operations include the de-energization and restoration of each bus.

4. The physical locations of the major components, controls and indication needed to perform Auxiliary Power System operations were included.

C. Emergency Operations

1. From the lesson you should be able to recall the design base and Auxiliary Power System response to the loss of offsite power, loss of selected onsite sources and loss of coolant accident events.

2. Knowledge of emergency events includes DG electrical operations and operation of shunt trips. This included knowledge of the DG automatic actions for undervoltage conditions and response when these conditions occur in conjunction with ECCS initiation signals.

D. Technical Specifications

1. From the review of Technical Specification you should be able to describe what equipment makes up an electrical distribution system and what portions of the distribution systems are required for various plant operations.

2. Given the references you should be able to apply the Technical Specification requirements to determine the specified actions for various Limiting Conditions of Operation and the associated time limits.

E. Operating Procedures

1. From a review of plant procedures related to the Auxiliary Power system you should be able to recall the major steps of the procedures and associated precautions. For the precautions you should be able to explain and apply the bases for each.

2. This knowledge should directly support your ability to complete the in-plant training on the Auxiliary Power System.

ATTACHMENTS & FIGURES

Attachments

Figures

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010–3A	DC FAILURE RES AUX TRANSF A (B) [C] PROT SYS S	20 amp Power Supply Fuses FU 1, FU 4	Fuse Blown	STATUS ALARM ONLY • Automatic RAT ground fault trips and fault pressure trips are supplied by this system.
		12 VDC Power Supply 1DC16E Ckt #21	Tripped	
		Loss of DC power relay SYS S 74S-RT1(A)[C] {RAT B(A)[C]}	1PL90JA: De-energized	
		Phase Overcurrent Relay with Breaker Failure RAT A[C] 150/151/150 BFS-RTA[C]		
		Neutral Overcurrent Ground Fault Relay RAT A[C] 151N/551N RTA[C]		

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010–3B	DC FAILURE RES AUX TRANSF A (B) [C] PROT SYS F	20 amp Power Supply Fuses FU 3, FU 6	Fuse Blown	STATUS ALARM ONLY • Automatic fault protection for the RAT and Buses 1RT4, 1RTC14, 1RTC4, 1RTC4 & 1RT6 are supplied by this system.
		12 VDC Power Supply 1DC16E Ckt #21	Tripped	
		Loss of DC power relay SYS F 74F-RT1(A)[C] {RAT B(A)[C]}	1PL90JA: De-energized	
		Current Differential Protection relay 6.9 KV 1A/1B (4.16 KV 1B) 87/150 BFS-RTA[C]		
5010-3E	DC FAILURE ERAT PROT SYS S	20 Amp Power Supply Fuses FU 2 FU 4	FUSE BLOWN	STATUS ALARM ONLY • Loss of all automatic RAT Ground Fault trips and Fault Pressure trips are disabled
		125V DC Power Supply 1DC17E Ckt #23	TRIPPED	
5010-3F	DC FAILURE ERAT PROT SYS F	10 Amp Power Supply Fuses FU 1 FU 3	FUSE BLOWN	STATUS ALARM ONLY • All automatic fault protection for the ERAT and Bus 1ET4 are disabled.
		125V DC Power Supply 1DC17E Ckt #23	TRIPPED	

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-4A	LOCK-OUT TRIP RES AUX TRANSF A(B)[C] PROT SYS S	86S-RT1 (RAT 'B') at 1PL90J 86S-RTA (RAT 'A') at 1PL90JA 86S-RTC (RAT 'C') at 1PL90JA	ENERGIZED	• RAT-1 Circuit Switcher, 4538 lockout trip. • Bus lockout on 1RT4, 1RT6, 1RTC4, or any other RT or ET bus being supplied by RAT A(B)[C]. • RAT 'B' SVC Trip (refer to 5011-7E).
5010-4B	LOCK-OUT TRIP RES AUX TRANSF A(B)[C] PROT SYS F	86F-RT1 (RAT 'B') at 1PL90J 86F-RTA (RAT 'A') at 1PL90JA 86F-RTC (RAT 'C') at 1PL90JA	ENERGIZED	• RAT-1 Circuit Switcher, 4538 lockout trip. • Bus lockout on 1RT4, 1RT6, 1RTC4, or any other RT or ET bus being supplied by RAT A(B)[C]. • RAT 'B' SVC Trip (refer to 5011-7E).

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-4E	ERAT LOCK-OUT TRIP PROT SYS S	86S-ET	ENERGIZED	• ERAT Circuit Switcher, B018 lockout trip. • Bus lockout on 1ET4 or any other ET or RT bus being supplied by the ERAT. • ERAT SVC Trip (refer to 5011-8E).
5010-4F	ERAT LOCK-OUT TRIP PROT SYS F	86F-ET	ENERGIZED	• ERAT Circuit Switcher, B018 lockout trip. • Bus lockout on 1ET4 or any other ET or RT bus being supplied by the ERAT. • ERAT SVC Trip (refer to 5011-8E). • Auto deluge system initiates for the ERAT.

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-5A	SUDDEN PRESSURE RES AUX TRANSF A(B)[C]	Fault Pressure Trip and Lockout Relay (RAT 'A') SP-1, SP-2 63X-1, 63X-2	4 psi (1/2 twice trip logic)	• 6900V Bus 1A and 1B reserve breaker lockout. • 4160V Bus 1A1, 1B1 and 1C1 main breaker lockout. • 4160V Bus 1A and 1B reserve breaker lockout. • RAT-1 Circuit Switcher, 4538 trip. • Auto deluge system initiates (RAT 'B' only).
		Fault Pressure Trip and Lockout Relay (RAT 'B', RAT 'C') 63X-1, 63X-2	4 psi (2/2 trip logic)	
5010-5F	SUDDEN PRESSURE/ FAULT PRESSURE ERAT	Tap Chgr: Press Relay 63B [0PY-AP074]	6.5 psi	Auto actions only via Fault Press Trip/LO Relay 86FP-ET: • 4160V Bus 1A1, 1B1 and 1C1 reserve breaker lockout. • Lockout of ET or RT buses connected to the ERAT. • ERAT Circuit Switcher, B018 trip. • ERAT auto deluge
		ERAT: Sudden Pressure Relay 63SP [0PY-AP072]	≥ 5.5 psi/sec	
		ERAT: Fault Press Relay 63FP [0PY-AP073]	3 - 3.25 psi	
		ERAT: Fault Press Trip/LO Relay [Fed from 63FP/0PY-AP073] 86FP-ET	Energized	

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-6A	TROUBLE RES AUX TRANSF A(B)[C]	**RAT 'A' Devices** 27-1 (Loss of Main Supply) 27-2 (Loss of Fan Control-1) 27-3 (Loss of Fan Control-2) **RAT 'B' & 'C' Devices** 27-1 (Loss of Main Supply) 27-2 (Loss of Fan Control)		STATUS ALARM ONLY
		RAT 'A' Device 63PR-1 (Main Tank Pressure Relief) **RAT 'B' & 'C' Devices** 63PR-2 (Tank Pressure Relief) 63GD (Gas Detector)		
		RAT 'A' Device 71Q-1 (Main Tank Low Oil Level) **RAT 'B' & 'C' Device** 71Q-1 (Conservator Low Oil Level)		
		RAT 'A' Device 90HV (High Voltage) - **Disabled** **RAT 'B' & 'C' Device** 90T (High Voltage) – **Disabled**		
		RAT 'A' Device 96C (Gas Monitor Alarm-1, Gas Monitor Alarm-2, Gas Monitor Failure) **RAT 'B' & 'C' Device** 63GM (Gas Monitor Alarm-1, Gas Monitor Alarm-2, Gas Monitor Failure)		
		RAT 'A' Device 83 (Loss of Normal Supply)		

List of Significant Annunciators
Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-6F	TROUBLE ERAT	Back-Up Relay [ERAT Voltage Regulator trans to Back Up Voltage Regulator M-0329A]	Energized	STATUS ALARM ONLY
		Intertaire System Pressure Switches	High: 8.5 psi Low: 0.25 psi Empty N2 Cyl: 200 psi	Inertaire Gauge #7 Gauge #7 Gauge #1
		Loss of Norm Supply [ERAT 480V supply from 0AP169E (138KV Source) transferred to Emergency Backup 12KV Source]	Energized	STATUS ALARM ONLY
		Loss of Voltage [TDDO Agastats] 27-1: Cool Grp #1 fans (5 total) 27-2: Cool Grp #2 fans (4 total) 27-3: Cool Sys Cont Ckts 27-4: Backup Volt Reg '59'	1 minute time delay for each Agastat	STATUS ALARM ONLY
		Low Oil Level	Low	Liquid Level (Xfrm & LTC)
		Mechanical Relief Device	Flow in line to oil retention pit	STATUS ALARM ONLY

List of Significant Annunciators

Panel 1H13-P870 Section 5010 Switchyard

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5010-7A	HIGH TEMP RES AUX TRANSF A(B)[C]	Oil Temperature Indicating Switch 26Q-1 (RAT 'A') 26Q (RAT 'B', 'C')	90°C (RAT A) 80°C (RATs B & C)	STATUS ALARM ONLY
		Transfer Winding Temperature Indicating Switches 49T1 (RAT 'A') 49A (RAT 'B', 'C')	105°C (RAT A) 95°C (RATs B & C)	
5010-7F	HIGH TEMP ERAT	Hotspot [Winding] Thermometer 49-3[0TIS-AP070]	105°C	Winding Temperature
		Hot Oil Temp – Transformer 26Q-1[0TIS-AP063]	90°C	Liquid Temperature
		Hot Oil Temp - Tap Changer 26Q-2[0TIS-AP064]	90°C	LTC Temperature
5010-8A	LTC VLT REG FAIL RES AUX TRANSF A, (B), [C]	• LTC Volt Reg. Failure • LTC Volt Reg. Backup Alarm • LTC Tank Pressure Relief (RAT 'A') • LTC Pressure Relief (RAT 'B' & 'C') • LTC Tank Low Oil Level (RAT 'A') • LTC Low Oil Level (RAT 'B' & 'C') • LTC Vacuum Bottle Failure (RAT 'B' & 'C')		STATUS ALARM ONLY

List of Significant Annunciators
Panel 1H13-P870 Section 5011 6900 v Distribution

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5011-1C	AUTO TRIP BREAKER	6.9 KV BUS 1A (1B) MAIN BRKR TRIP	Handswitch in CLOSE with breaker OPEN	If Bus Fault: • Assoc 480V Xfrm & Main Feeder Bkrs Open. • Assoc 480V X-Tie Bkr Close. If Main Generator Trip: • 6.9 KV Bus 1A (1B) Reserve Breakers close.
		6.9 KV BUS 1A (1B) RSRVE BRKR TRIP		If the alarm is not caused by closing the 6.9 KV Bus 1A (1B) Main Breaker: • Assoc 480V Xfrm & Main Feeder Bkrs Open. • Assoc 480V X-Tie Bkr Close.
		480V TRANSFRMR BRKR TRIP		• Auto trip of any associated remotely controlled 480V breakers.
		480V MN BRKR TRP		• 480V tie breaker closes (Non-Fault trip only)
		480V BUS TIE BRKR TRP		• STATUS ALARM ONLY
5011-1E	DC FAILURE 6900V BUS	ALARM RELAY 74-51A, B		• Breakers that lose status light indication, also lose trip power and can only be tripped manually.
5011-1F	AC UNDERVOLTAGE 6900V BUS	UV RELAY 527X2-51A/B		• Assoc 480V Xfrm & Main Feeder Bkrs Open. • Assoc 480V X-Tie Bkr Close.

List of Significant Annunciators

Panel 1H13-P870 Section 5011 6900 v Distribution

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5011-2C	AUTO XFER 6900V BUS RES FEED BKR	BREAKER CONTACT 552-521A&B 52A	Bkr Closed & HS in Auto After Trip	• 6.9 KV Bus 1A(1B) Mn Bkr trip. • 6.9 KV Bus 1A(1B) Rsve Bkr closes.
5011-2D	XFER BLOCKED 6900V BUS	TRIP AND LOCKOUT RELAY 586-501A&B		6900V Bus 1A, 1B Reserve Breaker LOCKED OUT. • Assoc 480V Xfrm & Main Feeder Bkrs Open • Assoc 480V X-Tie Bkr Close
5011-3D	AUTO TRIP 480V BUS FEEDER BKR	BREAKER ALARM RELAY 452 r		STATUS ALARM ONLY (Note that resetting (pushing in) the white popout button on affected Unit Sub breaker, which tripped on overcurrent, will clear the annunc.).
5011-3E	DC FAILURE 480V BUS	ALARM RELAY 74		Breakers that lose status light indication, also lose trip power and can only be tripped manually.
5011-3F	AC UNDERVOLT AGE 480V BUS	UV RELAY 427X1		STATUS ALARM ONLY
5011-3G	HIGH TEMP 480V AUX TRANSFORMER	WINDING TEMP	200°C	STATUS ALARM ONLY
5011-4D	AUTO CLOSE 480V BUS TIE BKR	Bkr Closed & HS in Auto After Open	Bkr Closed & HS in Auto After Open	STATUS ALARM ONLY Non-Fault Trip of the associated 480V Bus Main Breaker
5011-4E	AUTO CLS BLOCKED 480V BUS TIE BKR	TRIP AND LOCKOUT RELAY		STATUS ALARM ONLY Overcurrent trip of the associated 480V Transformer Breaker

List of Significant Annunciators

Panel 1H13-P870 Section 5011 6900 v Distribution

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5011-5C 5011-5D	SUDDEN PRESS UAT 1A UAT 1B	SUDDEN PRESSURE RELAY 63X-AT1A 63X-AT1B	2/2 logic both Manhole and Tank	• Main Generator Trip and Lockout • Transfer of both 6.9 & 4.16KV Buses 1A & 1B to the RAT for either transformer trip. • UAT 1A(1B) Auto Deluge.
5011-5E	LOCK-OUT TRIP BUS 1RT4 PROT SYS S	TRIP AND LOCK-OUT RELAY 286S-B1		• 4160V Bus 1A1, 1B1 and 1C1 Main Breaker Lock-Out Trip. • 4160V Bus 1A Reserve Breaker Lock-Out Trip.
5011-5F	LOCK-OUT TRIP BUS 1RT6 PROT SYS S	TRIP AND LOCK-OUT RELAY 586S-B1		6900V Bus 1A and 1B Reserve Breaker Lock-Out Trip.
5011-5G	LOCK-OUT TRIP BUS 1ET4 PROT SYS S	TRIP AND LOCK-OUT RELAY 286S-BE		4160V Bus 1A1, 1B1 and 1C1 Reserve Breaker Lock-Out Trip
5011-6C 5011-6D	TROUBLE UAT 1A UAT 1B	OIL LEVEL GAGE	LOW	STATUS ALARM ONLY
		UV ALARM RELAY		
		PRESSURE RELIEF	10 psig	

List of Significant Annunciators
Panel 1H13-P870 Section 5011 6900 v Distribution

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5011-6E	LOCK-OUT TRIP BUS 1RT4 PROT SYS F	TRIP AND LOCK-OUT RELAY 286F-B1		• 4.16 KV Bus 1A1, 1B1 and 1C1 Main Breaker Lock-Out Trip. • 4.16 KV Bus 1A Reserve Breaker Lock-Out Trip. • Auto deluge initiates on RAT due to 86F-RT1 device (5010-4B).
5011-6F	LOCK-OUT TRIP BUS 1RT6 PROT SYS F	TRIP AND LOCK-OUT RELAY 586F-B1		• 6.9 KV Bus 1A and 1B Reserve Breaker Lock-Out Trip. • Auto deluge initiates on RAT due to 86F-RT1 device (5010-4B).
5011-6G	LOCK-OUT TRIP BUS 1ET4 PROT SYS F	TRIP AND LOCK-OUT RELAY 286F-BE		4160V Bus 1A1, 1B1 and 1C1 Reserve Breaker Lock-Out Trip. Auto deluge initiates on ERAT due to 86F-ET device (5010-4F).
5011-7C 5011-7D	HIGH TEMP UAT 1A HIGH TEMP UAT 1B	WINDING TEMP IND 1TS-AP006A, B, & C 1TS-AP009A, B, & C	105°C	STATUS ALARM ONLY
		OIL TEMP IND 1TS-AP005 1TS-AP008	90°C	
5011-8C 5011-8D	HIGH-HIGH TEMP UAT 1A UAT 1B	WINDING TEMP IND 1TS-AP006A, B, & C 1TS-AP009A, B, & C	120°C	STATUS ALARM ONLY If unable to correct: MANUAL transfer 6.9 KV &/or 4.16 KV Bus 1A (1B) to their respective RAT.

Attachment C (Page 1 of 2)

List of Significant Annunciators

Panel 1H13-P870 Section 5012 4160 v Distribution

<table>
<tr><th>Window Name</th><th>Window Nomenclature</th><th>Actuating Device</th><th>Setpoint</th><th>Automatic Action</th></tr>
<tr><td rowspan="5">5012-1A</td><td rowspan="5">AUTO TRIP BREAKER</td><td>Auto Trip 4160V MAIN BRKR 1A (1B)</td><td></td><td><u>If Bus Fault</u>
• Associated 480V transformer breakers trip on undervoltage .
<u>If Main Generator Trip</u>
• 4160V Bus 1A (1B) Reserve breaker auto closes.</td></tr>
<tr><td>Auto Trip 4160V RSRV BRKR 1A (1B)</td><td></td><td>If the alarm is <u>not</u> caused by closing 4160V Bus 1A (1B) main breaker:
• Associated 480V transformer breakers trip on undervoltage.</td></tr>
<tr><td>Auto Trip 480V TRANSFORMER BREAKER</td><td></td><td></td></tr>
<tr><td>Auto Trip 480V MAIN BREAKER:
• 480V Bus Bkr G, H, I, J, K, L, Q, or R
• 480V I & Q or 480V J & R Xfrm Bkrs</td><td></td><td></td></tr>
<tr><td>Auto Trip 480V TIE BREAKER:
Bus Q & R</td><td></td><td>STATUS ALARM ONLY</td></tr>
<tr><td>5012-1C</td><td>DC FAILURE</td><td>Alarm Relay
74-21A & B</td><td></td><td>STATUS ALARM ONLY
All breakers that lose status light indication also lose trip power and can only be tripped manually.</td></tr>
</table>

Attachment C (Page 2 of 2)
List of Significant Annunciators
Panel 1H13-P870 Section 5012 4160 v Distribution

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5012-1D	AC UNDER-VOLTAGE 4160V BUS	Undervoltage Relay 227X3-21A & B		• Undervoltage trip of all 480V transformer breakers that are fed from the 4160V Bus 1A (1B).
5012-2A	AUTO XFER 4160V RES FEED BKR	Trip Relay 286-221A & B		• 4160V Bus 1A and/or 1B main feeder breakers trip. • 4160V Bus 1A and/or 1B reserve feeder breakers close.
5012-2B	XFER BLOCKED 4160V BUS	Trip Relay 286-201A & B		• 4160V bus reserve breaker locked out. • Undervoltage trip of associated 480V transformer breakers. • Auto trip of associated 480V main breakers. • Auto closing of 480V bus tie breaker.
5012-3B	AUTO TRIP 480V BUS FEEDER BKR	Alarm Switch 452-400		STATUS ALARM ONLY (Note that resetting (pushing in) the white popout button on affected Unit Sub breaker, which tripped on overcurrent, will clear the annunciator).
5012-3C	DC FAILURE 480V BUS	DC Failure Alarm Relay 74-4		STATUS ALARM ONLY Breakers which lose status light indication also lose trip power and can only be tripped manually
5012-3D	AC UNDER VOLTAGE 480V BUS	AC Undervoltage Relay 427X1-4		STATUS ALARM ONLY

Attachment D (Page 1 of 3)
List of Significant Annunciators
Panel 1H13-P877 Section 5060 Division I

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5060-1B	AUTO TRIP BREAKER	4160V Main/Reserve Breaker Bus 1A1 AP-BC635 or BC636	Trip	• 4.16 KV Bus 1A1 Reserve/Main Bkr auto closes when the Main/Reserve Bkr trips (unless fault/overload on Bus 1A1). • If the 4.16 KV Bus 1A1 Reserve/Main Bkr fails to close, DG 1A auto start & load.
		Diesel Generator 1A Output Breaker AP-BC637	Trip	STATUS ALARM ONLY
		4160V Feeder Breaker AP-BC648	Trip	STATUS ALARM ONLY
		480V Bus A (0AP05E) Main Feed Breaker AP-BC661	Trip	STATUS ALARM ONLY
		480V Bus 1A (1AP11E) Main Feed Breaker AP-BC687	Trip	STATUS ALARM ONLY
5060-1D	NOT AVAILABLE 4160V BUS BREAKER	4160V Bus 1A1 Main Breaker	Trip	If Bus 1A1 Main Bkr tripped on overcurrent: • Bus 1A1 Reserve Bkr Auto Close if available. • If Reserve Bkr is unavailable, DG 1A will auto start & Close.
		4160V Bus 1A1 Reserve Breaker	Trip	If Bus 1A1 Reserve Bkr tripped on overcurrent: • Bus 1A1 Main Bkr Auto Close if available. • If Main Bkr is unavailable, DG 1A will auto start & Close.
		Diesel Generator 1A Output Breaker		STATUS ALARM ONLY
		480V A or A1 Feeder Breaker		STATUS ALARM ONLY

List of Significant Annunciators

Panel 1H13-P877 Section 5060 Division I

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5060-2B	AUTO XFER 4160V BUS RES/DG FEED BKR	Main Bkr Trip with auto close of either the Reserve or DG 1A Feed Bkr if the Reserve Bkr is unavailable.		• If trip was caused by non-fault conditions, Bus 1A1 Reserve Breaker auto closes. • If trip was due to a fault or if the 4160V Bus 1A1 Reserve Breaker fails to close, DG 1A auto starts and the Output Breaker attempts auto closes.
5060-2C	XFER BLOCKED 4160V BUS	• Overcurrent trip of either 1B1 Main or Reserve Breaker. • Breaker or bus fault, • Respective HS in Pull-to-Lock.		• Both the Main and Reserve Bkrs for Bus 1A1 receive a trip and lockout signal. • DG1A auto starts and attempts to auto close the DG output breaker.
5060-3B	DC FAILURE 4160V BUS	Control Power Monitor 74-21A1		Loss of control power disables auto control of 4.16 KV Bkrs requiring local breaker local operation.
5060-3C	AC UNDER VOLTAGE 4160V BUS	1st Level Undervoltage Relay 227X2-21A1	≥ 2345 V & ≤ 3395 V (nominal 2870 V)	• Trip of the Main (Rsrv) and close in of the Rsrv (Main), if voltage exists on standby bus. • If the Rsrv (Main) Bkr fails to close, DG1A starts; the Rsrv (Main) feeder will open & the Main (Rsrv) feeder locks-out; Bus 1A1 loads are stripped; & the DG1A closes in.
5060-3D	AC UNDER VOLTAGE SECOND LEVEL 4160V BUS	2nd Level Undervoltage Relay 227X1-21A1-2	≥ 4051 V & ≤ 4092 V (nominal 4072 V)	After 15 sec time delay, DG1A auto start; Reserve (Main) feeder will open & the Main (Reserve) feeder locks-out; Bus 1A1 loads are stripped; & the DG1A closes in.
5060-5C	AUTO TRIP 480V BUS FEEDER BKR	Auto Trip Any Feeder Breaker on 480V BUS A or 1A		STATUS ALARM ONLY

Attachment D (Page 3 of 3)

List of Significant Annunciators

Panel 1H13-P877 Section 5060 Division I

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5060-5D	NOT AVAILABLE 480V BUS MAIN FEED BKR	Bus A or 1A Main Feed Breakers	Racked-Out	STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.
		Bus A or 1A Control Power Monitor	Deenergized	
5060-6B	DC FAILURE 480V BUS	DC Control Power Failure 480V Bus A or 1A		STATUS ALARM ONLY Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.
5060-6C	AC UNDER VOLTAGE 480V BUS	480V Bus A Undervoltage Alarm	328V, 1 second @ 0 volts	Trip of MCR HVAC Supply & Return Fans 1VC03CA & 1VC04CA MCR HVAC Chiller, 0VC13CA
		480V Bus 1A Undervoltage Alarm		Trip of Diesel Generator Vent Fan 1A, 1VD01CA
5060-7B	HIGH TEMP 480V AUX TRANSFORMER	480V Bus A or 1A High Temperature	200°C	STATUS ALARM ONLY

List of Significant Annunciators
Panel 1H13 - P877 Section 5061 Division 2

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5061-1B	AUTO TRIP BREAKER	4160V Main/Reserve Breaker Bus 1B1 AP-BC638or BC639	Trip	• 4.16 KV Bus 1B1 Reserve/Main Bkr auto closes when the Main/Reserve Bkr trips (unless fault/overload on Bus 1B1). • If the 4.16 KV Bus 1B1 Reserve/Main Bkr fails to close, DG 1B auto start & load.
		Diesel Generator 1B Output Breaker AP-BC640	Trip	STATUS ALARM ONLY
		4160V Feeder Breaker AP-BC649	Trip	STATUS ALARM ONLY
		480V Bus B (0AP06E) Main Feed Breaker AP-BC662	Trip	STATUS ALARM ONLY
		480V Bus 1B (1AP12E) Main Feed Breaker AP-BC688	Trip	STATUS ALARM ONLY
5061-1D	NOT AVAILABLE 4160V BUS BREAKER	4160V Bus 1B1 Main Breaker	Trip	If Bus 1B1 Main Bkr tripped on overcurrent: • Bus 1B1 Reserve Bkr Auto Close if available. • If Reserve Bkr is unavailable, DG 1B will auto start & Close.
		4160V Bus 1B1 Reserve Breaker	Trip	If Bus 1B1 Reserve Bkr tripped on overcurrent: • Bus 1B1 Main Bkr Auto Close if available. • If Main Bkr is unavailable, DG 1B will auto start & Close.
		Diesel Generator B Output Breaker		STATUS ALARM ONLY
		480V 1B & B1 Feeder Breaker		STATUS ALARM ONLY

List of Significant Annunciators

Panel 1H13 - P877 Section 5061 Division 2

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5061-2B	AUTO XFER 4160V BUS RES/DG FEED BKR	Main Bkr Trip with auto close of either the Reserve or DG 1B Feed Bkr if the Reserve Bkr is unavailable.		• If trip was caused by non-fault conditions, Bus 1B1 Reserve Breaker auto closes. • If trip was due to a fault or if the 4160V Bus 1B1 Reserve Breaker fails to close, DG 1B auto starts and the Output Breaker attempts auto closes.
5061-2C	XFER BLOCKED 4160V BUS	• Overcurrent trip of either 1B1 Main or Reserve Breaker. • Breaker or bus fault, • Respective HS in Pull-to-Lock.		• Both the Main and Reserve Bkrs for Bus 1B1 receive a trip and lockout signal. • DG1B auto starts and attempts to auto close the DG output breaker.
5061-3B	DC FAILURE 4160V BUS	Control Power Monitor 74-21B1		Loss of control power disables auto control of 4.16 KV Bkrs requiring local breaker local operation.
5061-3C	AC UNDER VOLTAGE 4160V BUS	1st Level Undervoltage Relay 227X2-21B1	≥ 2345 V & ≤ 3395 V (nominal 2870 V)	• Trip of the Main (Rsrv) and close in of the Rsrv (Main), if voltage exists on standby bus. • If the Rsrv (Main) Bkr fails to close, DG1B starts; the Rsrv (Main) feeder will open & the Main (Rsrv) feeder locks-out; Bus 1B1 loads are stripped; & the DG1B closes in.
5061-3D	AC UNDER VOLTAGE SECOND LEVEL 4160V BUS	2nd Level Undervoltage Relay 227X1-21B1-2	≥ 4051 V & ≤ 4092 V (nominal 4072 V)	After 15 sec time delay, DG1B auto start; Reserve (Main) feeder will open & the Main (Reserve) feeder locks-out; Bus 1B1 loads are stripped; & the DG1B closes in.
5061-5C	AUTO TRIP 480V BUS FEEDER BKR	Auto Trip Any Feeder Breaker on 480V BUS B or 1B		STATUS ALARM ONLY

Attachment E (Page 3 of 3)

List of Significant Annunciators

Panel 1H13-P877 Section 5061 Division 2

<table>
<tr><th>Window Name</th><th>Window Nomenclature</th><th>Actuating Device</th><th>Setpoint</th><th>Automatic Action</th></tr>
<tr><td rowspan="2">5061-5D</td><td rowspan="2">NOT AVAILABLE 480V BUS MAIN FEED BKR</td><td>Bus B or 1B Main Feed Breakers</td><td>Racked-Out</td><td rowspan="2">STATUS ALARM ONLY
Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.</td></tr>
<tr><td>Bus B or 1B Control Power Monitor</td><td>Deenergized</td></tr>
<tr><td>5061-6B</td><td>DC FAILURE 480V BUS</td><td>DC Control Power Failure 480V Bus B or 1B</td><td></td><td>STATUS ALARM ONLY
Local breakers, which lose status light indication also lose control power, and can only be tripped by the static trip device.</td></tr>
<tr><td rowspan="2">5061-6C</td><td rowspan="2">AC UNDER VOLTAGE 480V BUS</td><td>480V Bus B Undervoltage Alarm</td><td rowspan="2">328V,
1 second @ 0 volts</td><td>Trip of MCR HVAC Supply & Return Fans 1VC03CB & 0VC04CB
MCR HVAC Chiller, 0VC13CB</td></tr>
<tr><td>480V Bus 1B Undervoltage Alarm</td><td>Trip of Diesel Generator Vent Fan 1B, 1VD01CB</td></tr>
<tr><td>5061-7B</td><td>HIGH TEMP 480V AUX TRANSFOR MER</td><td>480V Bus B or 1B High Temperature</td><td>200°C</td><td>STATUS ALARM ONLY</td></tr>
</table>

List of Significant Annunciators
Panel 1H13 – P601 Section 5062 Division 3

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5062-1A	AUTO TRIP 4160V BUS 1C1 MAIN FEED BKR	F or S System Lockout		• Bus 1C1 Reserve Breaker auto closes, unless a fault or overload on the bus caused trip. • If 4160V Bus 1C1 Reserve Breaker Fails to close, DG 1C auto starts and loads.
		Overcurrent	1240 amps or 1440 amps // with DG	
		Main Supply Undervoltage	2842V at 0.18 sec	
5062-1B	AUTO XFER 4160V BUS RES/DG FEED BKR	Bus 1C1 Main Feed Breaker	Tripped	• Reserve Bkr closes in if sufficient voltage exists. • If 2nd UV Relay (15 sec) times out, DG 1C starts; the Reserve (Main) Bkr will open & the Main (Reserve) Bkr will LO; the 4.16KV Bus 1C1 strips its loads; & the DG 1C closes in.
		Bus 1C1 DG Breaker	Auto Closure	
5062-1C	OVER CURRENT DIESEL GEN 1C	Overcurrent Relay	1440 amps at 9.5 sec	• OI trip is bypassed on a LOCA. • If DG // with Offsite, both Main & Reserve Bkrs trip & LO, if closed.
		OI with voltage restraint relay	1240 amps	• Main, Reserve, & DG output Bkrs trip & LO. • DG 1C trips.
5062-2A	AUTO TRIP 4160V BUS 1C1 RES FEED BKR	Manual Close Main Feed Bkr		• Main Breaker auto closes unless a fault or overload on 4160V Bus 1C1 caused trip. • If Main Breaker fails to close, DG 1C will auto start and load.
		F or S System Lockout		
		Overcurrent	1240 amps or 1440 amps // with DG	
		Main Supply Undervoltage	2842 Volts	
5062-2B	XFER BLOCKED 4160V BUS	OI trip & LO of Main or Reserve Bkr and failure of other to close.		• Main Reserve Bkrs trip & LO, if closed. • DG 1C auto starts and loads.

List of Significant Annunciators

Panel 1H13 – P601 Section 5062 Division 3

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5062-3A	AUTO TRIP DG FEED BKR	Manually closing Main or Reserve Breaker		STATUS ALARM ONLY If the DG 1C Bkr trips while the DG is the only supply to the 1C1Bus, bus will not automatically re-energize.
		DG 1C Trip		
		LOCA with DG 1C paralleled		
		DG 1C Trip/Lockout		
5062-3B	AC UNDER VOLTAGE 4160V BUS	1st Level UV Relay 27SX Cub 101 27SY Cub 105	≥ 2345 V & ≤ 2730 V (nom 2538 V)	• Trip of the Main (Rsrv), & close in of the Rsrv (Main), if voltage is sufficient on the standby bus. • If the Rsrv (Main) Bkr fails to close, the DG starts; the Rsrv (Main) feeder opens & the Main (Rsrv) feeder LO; the 1C1 Bus strips loads; & the DG closes in.
5062-4A	AUTO TRIP 480V TRANSFORMER BKR	Overcurrent Relay 51-1 & 51-3	40 amps @ 1.4 seconds	STATUS ALARM ONLY
5062-5B	AC UNDER VOLTAGE 480 BUS	Undervoltage Relay 27	328 V, 1 sec at zero volts	If OI exists in conjunction with the UV, 480V Bus 1C Transformer Breaker, 252-AT1C will auto trip.
5062-7A	DIV 3 TRIPPING CONTROL POWER FAILURE	Main Feeder UV Detection		STATUS ALARM ONLY
		Trip Pwr all Div 3 4160v Bkrs		

List of Significant Annunciators
Panel 1H13 - P680 Sections 5007 & 5008 4160 V Divisional Alarms

Window Name	Window Nomenclature	Actuating Device	Setpoint	Automatic Action
5007-5M	SAFETY RELATED 4.16 KV BUS HIGH VOLTAGE	4.16 KV Bus 1A1, 1B1, 1C1 Voltage AP-BA525 AP-BA530 AP-BA535	4251V	STATUS ALARM ONLY Restore bus voltage to ≤ 4300V. Required within 30 minutes to maintain OPERABILITY
5008-5L	4KV BUS LOW VOLTAGE	4.16 KV Bus 1A1, 1B1, 1C1 Voltage AP-BA525 AP-BA530 AP-BA535	4136V	• The loss of voltage relays will trip the RAT (ERAT), and close in the ERAT (RAT), if sufficient voltage exists on the standby bus. • If 2nd UV Relay (15 sec TD) activates for 4.16KV Divisional Bus the associated DG will start; the Rsrv (Main) feeder will open & the Main (Rsrv) feeder will LO; the bus will be stripped of its loads; and the DG will tie onto the bus.

Attachment H (Page 1 of 1)

DIVISIONAL COLOR CODES

Description	Color
Class 1E Division 1 Components	Yellow
Class 1E Division 2 Components	Blue
Class 1E Division 3 Components	Green
Class 1E Division 4 Components	Orange
Non-Class 1E Division 1 Associated Components	Yellow - White
Non-Class 1E Division 2 Associated Components	Blue - White
Non-Class 1E Division 3 Associated Components	Green - White
Non-Class 1E Division 4 Associated Components	Orange - White
Non-Safety Related Train A	Black or Gray
Non-Safety Related Train B	Black or Gray
Non-Safety Related Division X	Black or Gray

KIRK KEY INTERLOCKS

Description	Device Number	Normal Position	Location
RAT 'B' 4.16 KV Disconnect Switch to Bus 1ET4	ET14	OPEN	Outside above Service/Turbine Buildings Doors
ERAT 4.16 KV Disconnect Switch to Bus 1ET4	ET4	CLOSE	Control Building 737' Floor Level
RAT 'B' 4.16 KV Disconnect Switch to Bus 1RT4	RT14	CLOSE	Turbine Building 737', above Turbine/Service Building Door
4.16 KV Disconnect Switch from Bus 1RT4 to Unit 2	RT4	OPEN	Radwaste 737' in overhead of S-Line
6.9 KV Disconnect Switch from Bus 1RT6 to Unit 2	RT6	OPEN	Turbine Building 737' in overhead of S-Line
RAT A 6.9 KV Disconnect Switch to Bus 1RT6	RT16	CLOSE	Turbine Building 737' in overhead of S-Line
RAT C 4.16 KV Disconnect Switch to Bus 1B	RTC14	CLOSE	Above SB to TB Walkway

AUXILIARY POWER 4.16 KV & 6.9 KV CURRENT AND POWER INSTRUMENTATION (MCR)

MCR Panel P870

Ammeters

0-2000 amps
UAT 1A FDR to 6.9 KV Bus 1A Current
UAT 1B FDR to 6.9 KV Bus 1B Current
Bus 1RT6 FDR to 6.9 KV Bus 1A Current
Bus 1RT6 FDR to 6.9 KV Bus 1B Current

0-3000 amps
UAT 1A FDR to 4.16 KV Bus 1A
UAT 1B FDR to 4.16 KV Bus 1B
Bus 1RT4 FDR to 4.16 KV Bus 1A
Bus 1RTC4 FDR to 4.16 KV Bus 1B

Wattmeter

0-25 MW
UAT 1A FDR to 6.9 KV Bus 1A
UAT 1B FDR to 6.9 KV Bus 1B
Bus 1RT6 FDR to 6.9 KV Bus 1A
Bus 1RT6 FDR to 6.9 KV Bus 1B

0-22 MW
UAT 1A FDR to 4.16 KV Bus 1A
UAT 1B FDR to 4.16 KV Bus 1B
Bus 1RT4 FDR to 4.16 KV Bus 1A
Bus 1RTC4 FDR to 4.16 KV Bus 1B

MCR Panel P877

0-800 amps
Bus 1RT4 FDR to 4.16 KV Bus 1A1
Bus 1RT4 FDR to 4.16 KV Bus 1B1
Bus 1ET4 FDR to 4.16 KV Bus 1A1
Bus 1ET4 FDR to 4.16 KV Bus 1B1

MCR Panel P601

Wattmeter

0-5000 kW
Bus 1RT4 FDR to 4.16 KV Bus 1C1
Bus 1ET4 FDR to 4.16 KV Bus 1C1

Ammeter

0-600 amps
Bus 1RT4 FDR to 4.16 KV Bus 1C1
Bus 1ET4 FDR to 4.16 KV Bus 1C1

MCR Panel P827

0-2000 amps
UAT 1A FDR to 6.9 KV Bus 1A
UAT 1B FDR to 6.9 KV Bus 1B
Bus 1RT6 FDR to 6.9 KV Bus 1A
Bus 1RT6 FDR to 6.9 KV Bus 1B

0-3000 amps
UAT 1A FDR to 4.16 KV Bus 1A
UAT 1B FDR to 4.16 KV Bus 1B
Bus 1RT4 FDR to 4.16 KV Bus 1A
Bus 1RTC4 FDR to 4.16 KV Bus 1B

0-800 amps
Bus 1RT4 FDR to 4.16 KV Bus 1A1
Bus 1RT4 FDR to 4.16 KV Bus 1B1

AUXILIARY POWER BREAKER CODES

X – 52 – X – X - XX

System Voltage	Designates Device	Bus Voltage	Breaker Type	Bus Designation
X	52-	X	X	XX
5 = 6.9 KV	52 = AC Bkr	5 = 6.9 KV	0 = Main Breaker	1A
2 = 4.16 KV	52 = AC Bkr	2 = 4.16 KV	1 = Tie Breaker	1B1
4 = 480 V	52 = AC Bkr	4 = 480 V	2 = Reserve Breaker	1C1, etc.

Attachment L (Page 1 of 1)

UNIT 480V SUBSTATION and LOCAL MAIN FEEDER BREAKER CONTROL LOCATIONS

Unit Substation Main Feeder Breaker	Location of wall mounted control unit	Unit Substation Main Feeder Breaker	Location of wall mounted control unit
480 V Unit Sub 1A	AB 781' (East)	480 V Unit Sub 1B	AB 781' (West)
480 V Unit Sub 1F	CB 702'	480 V Unit Sub 1G	CB 702'
480 V Unit Sub 1J	TB 762'	480 V Unit Sub 1K	TB 762'
480 V Unit Sub A	CB 825'	480 V Unit Sub B	CB 825'
480 V Unit Sub E	RW 762'	480 V Unit Sub G	RW 762'
480 V Unit Sub F	RW 762'	480 V Unit Sub H	RW 762'
480 V Unit Sub I	RW 762'	480 V Unit Sub J	RW 762'
480 V Unit Sub K	CB 825'	480 V Unit Sub L	CB 825'
480 V Unit Sub M	SB 722'	480 V Unit Sub N	SB 722'
480 V Unit Sub 1H	TB 737'	480 V Unit Sub C	RW 737'
480 V Unit Sub 1D	AB 762'	480 V Unit Sub O	CB 719'
480 V Unit Sub P	CB 719'	480 V Unit Sub D	RW 737'
480 V Unit Sub 1E	AB 762'	480 V Unit Sub 1L	AB 762'
480 V Unit Sub 1M	AB 762'	480 V Unit Sub 1I	TB 737'

Attachment M (Page 1 of 1)

OPEX – Critique OPS-98-12

PT Fuse Operations Momentarily De-energized 4160 Volt Bus 1A1 and Cause a Loss of Shutdown Cooling

October 1998 while in cold shutdown (Mode 4), the 4160 volt Bus 1A1 momentarily de-energized causing a loss of shutdown cooling. The 1A1 Bus was being feed through the reserve supply breaker (ERAT) while the main feed breaker (RAT) was tagged-out for testing of the Static Var Compensator modification. While Operations personnel were attempting to replace Potential Transformer (PT) fuses to clear the tagout on the main feed breaker, the area operator inadvertently opened the Potential Transformer (PT) fuse compartment door for the bus. This caused the Bus PT fuse connections to open while the ERAT was carrying the bus. De-energizing the Bus PT fuses satisfied the logic for opening the ERAT feed breaker and starting the Division 1 Diesel Generator. The DG successfully started closed in to carry the 1A1 busloads. The momentary loss of power also caused a loss of Fuel Pool Cooling and Cleanup, Fuel Building HVAC, and RHR Pump A. The RHR A pump was in the Shutdown Cooling Mode at the time. Shutdown cooling was re-established by re-starting the A RHR pump.

Earlier in the shift the Operators restored the main feeder breaker for the 1C1 Bus. After some searching the operators found the main feeder breaker and the Bus PT fuses inside the 1C1 Switchgear. To access them you must first open the Auxiliary Cubicle door, then pull out the drawer for the fuses. There is a separate drawer for the main breaker fuses and one for the bus fuses. The danger tag was placed on the drawer making it visible only after opening the cubicle door. This effort was complicated by a miss match between the Switchgear labeling and the tagout documents.

Prior to the start of the tagout restoration work a pre-job brief was conducted including the tags to be removed, sequence for the restoration, ensuring all workers were signed off, and details of the switching order. The locations for the PT fuses were not discussed; however, this type of discussion is not typical for a pre-job briefing.

After restoring the 1C1 Bus the Operators completed the restoration of a 12 KV tagout and switching order, and then proceeded to the 1A1 Switchgear. At the 1A1 Switchgear, again they were to clear the tagout on the main feeder breaker. The Operators were familiar with the PT fuse locations and did not know that the main feeder breaker PT fuses are in the back of the Switchgear behind the main feeder breaker. The Bus PT fuses are located on the front of the 1A1 Switchgear above the main feeder breaker.

The Bus PT fuse compartment did not have a tag hanging on it. The main feeder breaker PT compartment did have a tag hanging on the front, but it was located in the back of the Switchgear. The tagout documents did have a note that the tag was located in the back of the Switchgear. Based on what they had experienced at the Div 3 Switchgear they were not concerned by what they perceived as a discrepancy between the labeling at the Switchgear and the tagout documents. They also expected to have to open a compartment prior to being able to view the actual danger tag. With these thoughts they opened the PT compartment for the Bus PT fuses.

When the Bus PT fuse compartment was opened, interlocks immediately cause the associated low voltage circuits to be de-energized though PT drawer interlocks resulting in de-energizing the 1A1 Bus.

OPEX – SER 3-10 (Previously SEN 282)
Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

INPO	SIGNIFICANT EVENT REPORT	SER 3-10

Executive Summary

On March 28, 2010, H. B. Robinson Steam Electric Plant sustained damage to two 4-KV buses and the unit auxiliary transformer (UAT) when an arc flash occurred in a cable conduit and the bus supply circuit breaker failed to open on overcurrent. Subsequently, an automatic reactor scram occurred that was complicated by electrical fire response, loss of power to balance-of-plant equipment, and a temporary loss of power to emergency bus E2. Following the reactor scram, a safety injection (SI) signal was initiated as a result of low pressurizer pressure when operator response to an uncontrolled reactor coolant system (RCS) cooldown was delayed. Additionally, reactor coolant pump (RCP) seal integrity was challenged when RCP seal injection flow became inadequate with component cooling water (CCW) flow to the RCP thermal barriers isolated. Operators were slow to recognize this problem, and they further threatened RCP component integrity when they restored CCW to the RCPs.

During recovery activities following the initial arc flash event, operators inappropriately reset the main generator (MG) 86 lockout relay, re-energizing the faulted bus causing additional damage to electrical switchgear and a second electrical fire. An Alert emergency was declared because the fire resulted in degraded safety-related systems required to achieve and maintain safe shutdown conditions.

Significant aspects of the event include the following:

- A 4-KV cable insulation fault initiated events that led to an automatic reactor scram, fires, equipment damage, and SI actuation.

- Operator actions to restore RCP seal cooling without checking RCP temperatures had the potential to thermally shock RCP seals, distort RCP shaft components, and cause boiling of the CCW in the RCP thermal barrier cooling coils.

- Control room operators did not effectively monitor important control board indications and act promptly to control key plant parameters, contributing to an automatic safety injection actuation, an uncontrolled cooldown, and a challenge to RCP seal cooling.

- Failure of the bus 4 to bus 5 tie breaker—a major contributor to the event—occurred because control power was not available as a result of a malfunctioning fuse that had been open-circuited for an extended period.

- The operating crew did not effectively manage resources to simultaneously handle the fire and plant transient.

- An inappropriate action that reset the MG 86 lockout relay reenergized the faulted bus components, causing a second arc flash that resulted in additional damage and endangered personnel in the area.

OPEX – SER 3-10 (Previously SEN 282)

Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

Description

On March 28, 2010, cable insulation on the 4-KV supply to non vital bus 5 at H. B. Robinson Steam Electric Plant failed at the bus 5 cabinet entry point (see Attachment N.2). The cable failure caused an arc flash event, internal damage to the UAT, and a subsequent cable fire in the conduit.

The reactor scram occurred during the shift crew meeting at the start of the shift. Most of the shift members were in a room in the work control center building that is separated from the turbine building. The control room supervisor (CRS), the operator at the controls (OATC), and the balance-of-plant (BOP) operator were in the control room participating in a teleconference with the rest of the crew members. The crew meeting was stopped, and the shift manager (SM),shift technical advisor (STA), and two auxiliary operators proceeded to the control room by way of the plant transformer area because the control room team had announced a loss of startup transformer (SUT) occurring with the scram. The erroneous loss of SUT diagnosis was based on the SUT energized light being extinguished for several seconds—most likely a result of degraded SUT voltage caused by the initial fault current. The SM and STA observed the fire on 4-KV bus 5 cabling and conduit near the transformer area. The SM and STA arrived in the control room approximately 4 minutes after the reactor scram and announced the fire at 4-KV bus 5.

After completing the required immediate action steps of the EOPs, the CRS assigned the BOP operator to initiate the plant abnormal operating procedure (AOP) for fire events. The BOP operator was not available for EOP actions or parameter monitoring for the next 35 minutes of the event. During this period, the SM and STA were concurrently evaluating the emergency plan criteria, initiating calls for off-site fire assistance, and making duty manager notifications. Little oversight of the control room team activities was achieved during the first 25 – 30 minutes of the event.

(See Attachment N.1 for the following discussion)

<u>When the fault occurred, circuit breaker 52/24 did not trip on over current as expected and remained closed throughout the event. A faulty fuse disabled the breaker trip control circuit. Timely repair of a deficiency on breaker 52/24 local indicating lights may have prevented this breaker failure. This deficiency was first identified in November 2008.</u> As a result of the breaker failure, the fault persisted on buses 4 and 5 while the time over current protection for bus 4 feeder breaker 52/20 began timing. During this over current timing period, the fault caused voltage for buses 4 and 5 to become significantly depressed and the B RCP motor slowed the RCP, actuating the low RCS flow reactor protection logic for the B RCS loop, which tripped the reactor.

The fault current was initially fed from the UAT. After three to four seconds, the UAT failed internally and tripped on fault pressure protection, initiating an MG 86 lockout and live fast bus transfer by closing breaker 52/19 and opening breaker 52/20. The fault was then transferred from the UAT to the SUT. Following transfer of the fault to the SUT, voltage for bus 3 became significantly depressed, resulting in actuation of the loss-of-voltage relays for the E-2 safety bus. E-2 then separated from 4- KV bus 3, the B emergency diesel generator auto started and connected to bus E-2, and the load sequencer ran as designed.

OPEX – SER 3-10 (Previously SEN 282)

Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

After several seconds, the time over current relays for 52/19 actuated and tripped the breaker, clearing the fault and ending the first electrical fault event.
The loss of electrical power in the plant caused the moisture separator reheater drain tank alternate dump valves to the condenser to fail open and prevented remote closing of the moisture separator reheater steam shutoff valves, resulting in an uncontrolled RCS cooldown. The RCS cooldown exceeded 100 degrees in 60 minutes and led to an automatic low pressurizer pressure SI signal. The SI system injected to the reactor coolant system for approximately 12 minutes with a maximum flow of approximately 260 gpm. The main steam isolation valves closed automatically when instrument bus (IB) 3 lost power and this stopped the RCS cooldown. IB 3 lost power from an unknown cause although an auxiliary operator bumped the IB 3 inverter breaker while traveling to restore power to B battery charger that was lost when emergency bus E-2 was deenergized. Additionally, EOPs require the battery charger to be reenergized in 30 minutes after a power loss, and it took operators 38 minutes to complete this task.

Station expectations require operators to manually initiate SI if an automatic set-point is being approached. However, the operators did not closely monitor pressurizer pressure because they were focused on the fire response and executing emergency operating procedure (EOP) steps without taking time to observe key plant parameters and trends. Additionally, the operators anticipated a high steam line differential pressure SI based on previous training experiences involving a loss of RCP at power.

Instrument bus 4 experienced a loss of power as a result of emergency bus E-2 losing power temporarily. The loss of IB 4 power initiated a false high thermal barrier CCW flow signal causing the thermal barrier return flow control valve (FCV-626) to isolate CCW cooling to the RCP thermal barriers when power was restored to E-2. This condition went undetected by the operating crew for 39 minutes. Also, other instruments needed to complete scram immediate actions lost power when IB 4 lost power and operators were required to use alternate indicators to verify immediate actions.

The charging pumps were providing seal cooling injection flow to the RCPs following the loss of thermal barrier cooling. When the safety injection occurred, charging flow decreased from 65 gpm to 18 gpm as a result of automatic (design) tripping of the charging pump running on bus E-2, causing the parallel seal injection flow to also be significantly reduced. The amount of injection flow to each RCP seal is only indicated locally near the charging pump and has no computer monitoring capability. RCP bearing water temperatures on all three RCPs began to slowly increase. The differential pressure on the RCP labyrinth seal indirectly indicates adequacy of injection flow to seals. A positive labyrinth seal differential pressure indicates seal injection flow into the RCS. The differential pressure on the B RCP went to zero immediately after the SI, and the differential pressure on the operating pumps dropped significantly. At that point, the shutdown B RCP had no seal cooling from the thermal barrier heat exchanger and seal injection flow was uncertain.

OPEX – SER 3-10 (Previously SEN 282)

Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

Nineteen minutes after the SI signal, an air-operated valve on the alternate charging line to the RCS failed open because containment instrument air is isolated as a result of a phase A isolation and a slow air leak on the valve diaphragm. Indicated charging flow to the RCS increased from16 gpm to 25 gpm. At the same time, labyrinth seal differential pressure on the operating pumps dropped significantly, reaching approximately zero on the A RCP. At that point, the A RCP seal injection cooling was in doubt, and CCW flow to the thermal barrier was isolated. Labyrinth seal differential pressure on the shutdown B RCP went negative, indicating probable flow of hot RCS water towards the seal. RCP bearing water and seal outlet temperatures on all RCPs began to increase. Operators are trained to refrain from initiating cooling to RCP seals if cooling has been lost for more than 15 minutes. Operators were not fully aware that seal injection flow and therefore seal cooling had degraded when they reopened FCV-626. Seal leakoff temperature on the B RCP was at 195 degrees F and within 15 minutes of boiling when FCV-626 was opened.

During the event, the expected automatic actions on low-low volume control tank level to transfer charging pump suction to the refueling water storage tank (RWST) did not occur because of an equipment malfunction. This condition went undetected by the operating crew for 49 minutes. Also, the automatic makeup system had not been restarted after the power loss. The running charging pump lost suction and stopped delivering flow to the reactor coolant system and reactor coolant pump seals after 37 minutes (time 19:37). RCP seal cooling was reestablished through manual action to re-open component cooling water thermal barrier flow control valve FCV-626 at 19:31. In addition, the loss of filtered seal injection flow allowed unfiltered RCS water to flow through the RCP seals, requiring future inspection of the RCP seals for possible damage or particulate buildup.

While performing the GP-004, *Post Trip Stabilization*, procedure, (about three and one-half hours after the reactor scram), the operators were directed by the procedure to reset the MG 86 lockout relay. This action resulted in the SUT being reconnected to the uncleared fault on 4-KV bus 5. The action of positioning the MG 86 lockout relay to its reset state allowed breaker 52/19 antipump logic to reset, arming the breaker to reclose. Also, because the UAT fault pressure trip input to the MG 86 lockout relay was still locked in, the relay would not latch into the reset position and was tripped back to its lockout position. When this occurred, the fast transfer contacts reclosed breaker 52/19. This caused an arc flash in the back of breaker 52/24 switchgear cubicle. Operators did not fully understand how the plant would respond to the resetting of the relay. After several seconds, the time over current relays for 52/19 actuated and tripped the breaker, clearing the fault and ending the second electrical fault event.

During the second arc flash and fire, both safety-related 125-VDC battery buses developed electrical grounds that were likely caused by arc flash and fire damage. At this point, the shift manager declared an Alert and activated the emergency organization.

Plant conditions required a cooldown to MODE 5, and the operators placed the plant in MODE 5 on March 30. A refueling outage was scheduled for April 17, 2010. The outage was entered early to facilitate repairs to the damaged electrical equipment.

OPEX – SER 3-10 (Previously SEN 282)
Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

Causes and Contributing Factors

Problems contributing to this event occurred in the areas of equipment performance, operating crew performance, and organizational effectiveness. The various causes of the problems in these three areas are described below.

Equipment Performance:

Cable Fault Problems:

(NOTE: The 4-KV bus 5 was installed in 1986 to provide additional power for equipment additions to the plant.)

• The cables installed to provide power to 4-KV bus 5 did not have adequate strain relief at the bus connection

• Substitute cables were installed that did not meet original modification requirements for non-magnetic conduit, insulation quality, shielding, or flame retardation. Justification for the substitutions was not found during modification records retrieval.

Circuit Breaker (52/24) Failure:

• The breaker 30 amp control power fuse had an open circuit due to mechanical shock.

• Station personnel did not challenge the assumption that the circuit breaker closed indicating light deficiency, identified in November 2008, was caused by a light socket deficiency.

• Inadequate impact review of the breaker indicating light problem resulted in assigning the wrong priority for the work request.

Charging Pump Suction from the volume control tank to the RWST Auto-Transfer Failure:

• The volume control tank level comparator module was incorrectly configured during the previous refueling outage when the original Hagan comparator module was replaced withan NUS type module

• Post maintenance acceptance testing after the NUS comparator module replacement did not include a complete test of the module function. This testing deficiency introduced a latent equipment deficiency.

OPEX – SER 3-10 (Previously SEN 282)

Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

Operating Crew Performance:

Safety Injection Actuation:

• Ineffective control room command and control and assignment of resources allowed other control room activities, such as fire response phone calls, to delay progression through the EOPs and contributed to inadequate monitoring of critical plant parameters that would have identified the uncontrolled cooldown that led to the SI signal.

• The crew did not recognize the magnitude of the RCS cooldown. Based on not recognizing the magnitude of RCS temperature and pressure decrease the control room supervisor did not direct closing of the MSIVs. The control room supervisor could have directed local closing of the MSR shutoff valves or closed the main steam isolation valves (MSIV).

• Previous training experience led the crewmembers to believe they would receive an SI signal on high steam line differential pressure caused by the loss of one RCP. During and after the event the crew believed the SI was caused by a high steam line differential pressure signal rather than low pressurizer pressure. In three previous training scenarios with a loss of an RCP at power, a high steam line differential pressure signal resulted in an SI actuation.

• Insufficient detail in the EOPs concerning MSR isolation contingency actions and operator belief that the open MSR supply valves would not cause significant cooling contributed to a lack of response to stopping the cooldown. Also, the operators were not aware that the MSR drain tank alternate drain valves had failed open on loss of power.

Response to Reduced RCP Seal Cooling:

• The crew did not identify the loss of thermal barrier cooling until the emergency procedures directed monitoring this parameter.

• Crewmembers restored CCW to the RCP thermal barrier coolers without first verifying that adequate cooling had been maintained to the RCP seals from seal injection flow. Restoring CCW could have created a thermal shock condition on the RCP seals if the seal package had overheated from a loss of all cooling (CCW cooling and seal injection flow). The operating crewmembers took this action without referencing the appropriate alarm response procedure which would have required them to verify seal cooling prior to restoring CCW flow.

— Several plant procedures, including the EOP for response to SI, equate having a running charging pump to having adequate seal injection flow. Also, operator training and station procedures emphasize a 15-minute time limit for reinitiating cooling to an RCP seal when both seal injection flow and CCW flow are simultaneously lost. Either of these factors may have contributed to the operating crew's decision to open FCV-626 without first checking RCP seal temperatures.

OPEX – SER 3-10 (Previously SEN 282)
Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

• The volume control tank makeup control system transferred to an OFF condition when the makeup system lost power during the temporary loss of power to emergency bus E-2 and operators did not reset makeup after power was recovered.

• The crew did not identify that the volume control tank level was low until emergency procedures directed checking charging flow. At this time, the volume control tank was empty and the B charging pump had lost suction, causing inadequate seal injection flow and elevated RCP bearing water temperatures.

• The OATC positioned the volume control tank auto-transfer valve control switches to match the indicated valve positions believing the valves were in the correct position. The shift technical advisor noted the discrepancy, and the switches were moved to the correct position, causing the valves to properly align suction to the charging pumps from the RWST.

• The B charging pump was stopped because of concerns of damage from loss of suction flow. The C charging pump was then started, restoring seal injection flow and charging flow.

Resetting the Main Generator 86 Lockout Relay:

• Plant conditions were not fully evaluated following the fire and arc flash damage to electrical buses prior to operators performing procedure steps that assume a normal electrical alignment.

• Attempting to reset the MG 86 lockout relay reinstated the electrical fault on 4-KV buses4 and 5, causing further damage and endangering personnel in the area of these buses during the second event.

Organizational Effectiveness Factors:

• Improper behaviors, including leadership weaknesses that were identified during training scenarios and crew assessment shortfalls had not been adequately corrected and followup conducted.

• Station management had not aggressively pursued operating crew performance improvement corrective actions, ensured training was effective, monitored field performance, and provided critical timely feedback on performance shortfalls.

Outage control center (OCC) personnel did not provide a thorough post-event damage assessment or adequate assistance to the operating crew. OCC personnel were focused on identifying forced outage activities. Operations management did not request support, and plant management onsite did not direct action to support a damage assessment.

OPEX – SER 3-10 (Previously SEN 282)

Electrical Fault Complicated by Equipment Failures and Inappropriate Operator Action Leads to Damaged Electrical Equipment, Scram, Safety Injection, and Degraded Reactor Coolant Pump Seal Cooling

Lessons

There are many important lessons to be learned from this event. Case studies may be the most effective way of bringing out the appropriate lessons among key groups such as the management team, operations, maintenance, work management, and engineering. In addition to the lessons below, it is suggested that the significant aspects of the event as listed in the Executive Summary be thoroughly discussed and expectations for behaviors clarified and reinforced.

1. Past industry lessons about the importance of monitoring key plant parameters continue to apply. Shift leaders must ensure that control board operators are periodically monitoring all control board indications and responding to equipment failures. For example, monitoring of appropriate RCP seal cooling parameters is vital since overheating or thermally shocking these components can lead to a loss of coolant accident, bearing damage, or shaft warping.

2. The unavailability of control power to the 52/24 breaker was a key contributor to the complexity of the event. The fuse problem was long-standing.

3. Shift leaders need to ensure control room distractions are managed well, particularly during transient and accident conditions.

4. Shift leaders need to engage the plant's resources effectively during complex events. This involves ensuring resources are properly positioned to effectively cope with events that areoccurring.

5. Emergency operating procedures are intended to be performed as written. Conditions may arise; however, where it is advantageous to perform preemptive actions that are necessary to protect equipment, or lessen the severity of the transient. If the operators had taken preemptive action to close the MSIVs in this event, it is possible that the SI signal could have been avoided and it is probable that safety injection flow would not have injected. The station EOP user's guidance has provisions for preemptive action but this guidance was not implemented. Individual owner's groups offer guidance on implementing preemptive actions.

6. Events such as fires and loss of electrical power are particularly challenging because of the additional demands for operator attention. Control room operators need to enhance their focus on key parameters during these events. Training of operators to deal with complex multiple casualties such as what confronted the Robinson control room crew may not be adequate.

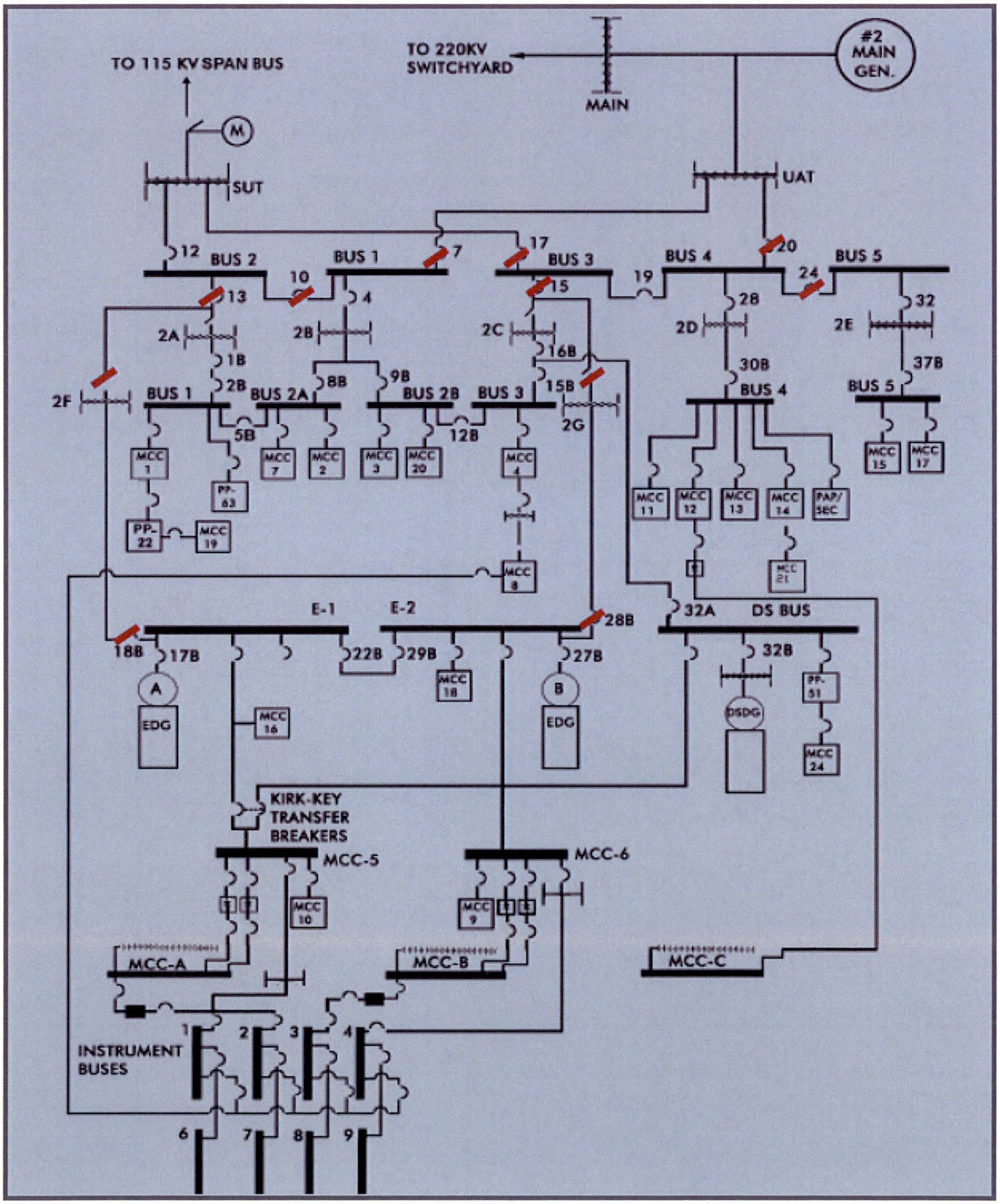
7. The consequences of performing each step of a recovery procedure following a fire and loss of electrical power event need thorough evaluation. Normal operating procedure guidance may not be appropriate for the conditions created by damage from the event. Using these procedures, especially when electrical systems are affected, without fully understanding the impact to the plant can substantially complicate the recovery.

8. If FCV-626 flow control circuitry had been powered from an uninterruptible power supply, the loss of bus E-2 would not have caused a loss of thermal barrier cooling.

Normal At-Power Electrical Bus Alignment

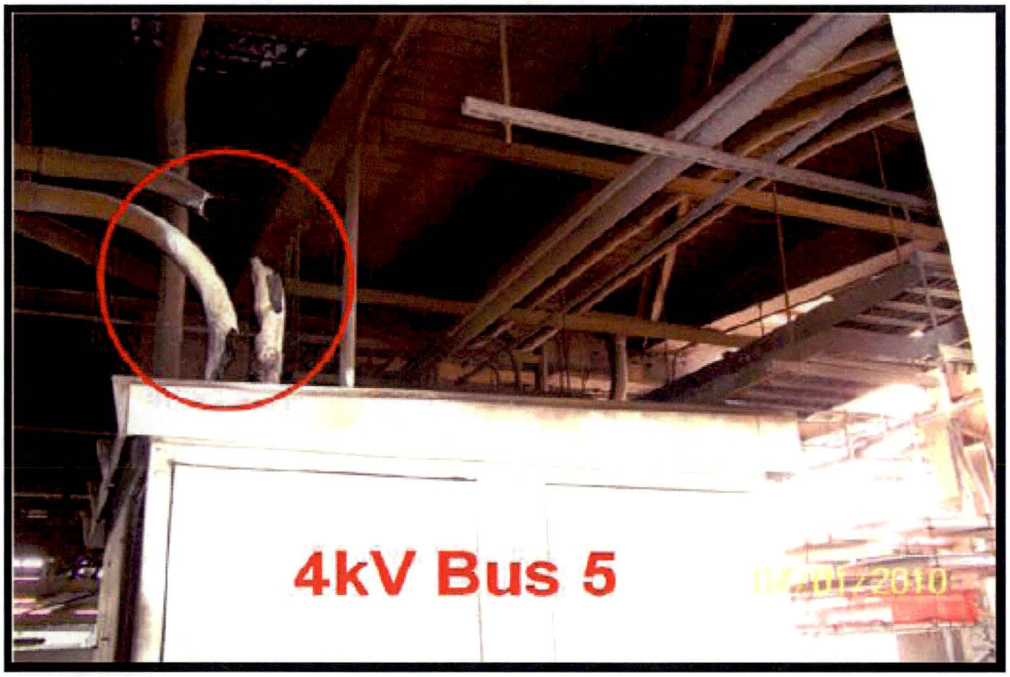
INPO **SIGNIFICANT EVENT REPORT** **SER 3-10**

(Shown for breakers that are closed to 4-kV buses and safety buses E-1 & E-2)



Attachment N.2 (Page 1 of 1)
4-KV Buses 4 & 5 Damage

INPO **SIGNIFICANT EVENT REPORT** **SER 3-10**



NRC IN 2012-03 - DESIGN VULNERABILITY IN ELECTRIC POWER SYSTEM (BYRON EVENT)

DESCRIPTION OF CIRCUMSTANCES

Byron Station, Unit 2

System Description: The Byron Unit 2 electrical system consists of four nonsafety-related 6.9-kilovolt (kV) buses, two nonsafety-related 4.16-kV buses, and two 4.16-kV engineered safety features (ESF) buses. The two 4.16-kV ESF buses and two of the nonsafety-related 6.9-kV station buses normally are supplied by one of the two station auxiliary transformers (SATs) connected through one 345-kV offsite circuit. The remaining two nonsafety-related 6.9-kV station buses and two nonsafety-related 4.16-kV station buses normally are supplied by one of two unit auxiliary transformers (UATs) when the main generator is online. On January 30, 2012, Byron Station, Unit 2 experienced an automatic reactor trip from full power because of an undervoltage condition on two 6.9-kV electrical buses that power reactor coolant pumps (RCPs) B and C. A broken insulator stack for the phase C conductor on the 345-kV power circuit that supplies both SATs caused the undervoltage condition. This insulator failure caused the phase C conductor to break off from the power line disconnect switch, resulting in a phase C open circuit. Although the break in the power line may have caused phase C to ground, the 345-kV circuit does not have ground fault protection and the switchyard breakers did not open. After the reactor trip, the two 6.9-kV buses that power RCPs A and D, which were aligned to the UATs, automatically transferred to the SATs, as designed. Because phase C was open circuited, the flow of current on phases A and B increased and caused all four RCPs to trip on phase overcurrent. With no RCPs functioning, control room operators performed a natural-circulation cooldown. Even though phase C was open circuited, the SATs continued to provide power to the 4.16-kV ESF buses A and B because of a design vulnerability this event revealed. The open circuit created an unbalanced voltage condition (loss of phase) on the two 6.9-kV nonsafety-related RCP buses and the two 4.16-kV ESF buses. ESF loads remained energized momentarily, relying on equipment-protective devices to prevent damage from single phasing or an overcurrent condition. The overload condition caused several safety-related loads to trip. Approximately 8 minutes after the reactor trip, the control room operators diagnosed the loss of phase C condition and manually tripped breakers to separate the unit buses from the offsite power source. When the SAT feeder breakers to the two 4.16-kV ESF buses were opened, the loss of ESF bus voltage caused the emergency diesel generators (EDGs) to automatically start and restore power to the ESF buses. The licensee declared a Notice of Unusual Event based on the loss of offsite power. The next day, the licensee completed the switchyard repairs, restored offsite power, and terminated the Notice of Unusual Event.

<u>The licensee reviewed the event and identified design vulnerabilities in the protection scheme for the 4.16-kV ESF buses. The loss-of-voltage relay protection scheme is designed with two undervoltage relays on each of the two ESF buses. These relays are part of a two-out-of-two trip logic based on the voltages being monitored between phases A–B and B–C of ESF buses. Even though phase C was open circuited, the voltage between phases A–B was normal; therefore, the trip logic was not satisfied. Because the conditions of the two-out-of-two trip logic were not met, no protective trip signals were generated to automatically separate the ESF buses from the offsite power source.</u>

Exelon Generation.

Clinton Power Station
8401 Power Road
Clinton, IL 61727

U-604100
October 26, 2012

10 CFR 50.73
SRRS 5A.108

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: Licensee Event Report 2012-001-00

Enclosed is Licensee Event Report (LER) No. 2012-001-00: Loss of Secondary Containment Differential Pressure Due to Transformer Trip. This report is being submitted in accordance with the requirements of 10 CFR 50.73.

There are no regulatory commitments contained in this report.

Should you have any questions concerning this report, please contact Ms. Kathy Ann Baker, Regulatory Assurance Manager, at (217)-937-2800.

Respectfully,

William G. Noll
Site Vice President
Clinton Power Station

JLP/blf

Enclosures: Licensee Event Report 2012-001-00

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Clinton Power Station
Office of Nuclear Facility Safety – IEMA Division of Nuclear Safety

NRC FORM 366 (10-2010) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB: NO. 3150-0104 EXPIRES: 10/31/2013

Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the FOIA/Privacy Section (T-5 F53), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects.resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Clinton Power Station, Unit 1	05000461	1 OF 4

4. TITLE
Loss of Secondary Containment Differential Pressure Due to Transformer Trip

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
09	02	2012	2012	- 001 -	00	10	26	2012	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 097

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☐ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☒ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER *(Include Area Code)*
Kathy Ann Baker, Regulatory Assurance Manager	217-937-2800

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	EB	RLY	Q011	YES					

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)*	☒ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

At 2204 on September 2, 2012, the Emergency Reserve Auxiliary Transformer (ERAT) transferred unexpectedly to the Reserve Auxiliary Transformer, causing a trip of the Fuel Pool Cooling and Cleanup system pump 'A' and trip of the Fuel Building Ventilation system. Secondary Containment differential pressure increased above the Technical Specification 0.25 inches vacuum and was restored at 2219 on September 2, 2012, when the Standby Gas Treatment System was manually started. This event is being reported as a condition that could have prevented the fulfillment of a safety function per 10 CFR 50.73(a)(2)(v)(C). The trip of the ERAT was caused by a spurious station ground on one of the ERAT sudden pressure seal-in relay cards (63SPX) caused by a latent design error. The ground revealed itself when Electrical Maintenance technicians were performing circuit checks to determine the source of a ground indicated on the 125 Volts Direct Current motor control center 1F. A temporary modification was implemented to disable the seal-in trip feature of the 63SPX relay card.

NRC FORM 366A
(10-2010)

LICENSEE EVENT REPORT (LER)
CONTINUATION SHEET

U.S. NUCLEAR REGULATORY COMMISSION

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REV NO.	
Clinton Power Station, Unit 1	05000461	2012	- 001 -	00	2 OF 4

NARRATIVE

PLANT AND SYSTEM IDENTIFICATION

General Electric -- Boiling Water Reactor, 3473 Megawatts Thermal Rated Core Power
Energy Industry Identification System (EIIS) codes are identified in test as [XX].

EVENT IDENTIFICATION

Emergency Reserve Auxiliary Transformer Trip and Subsequent Loss of Secondary Containment Differential Pressure

A. Plant Operating Conditions Before the Event

Unit: 1	Event Date: 9/2/2012	Event Time: 2204 hours CDT
Mode: 1	Mode Name: Power Operation	Reactor Power: 97 percent

B. DESCRIPTION OF EVENT

On September 1 and 2, 2012, Clinton Power Station (CPS) experienced significant precipitation (rain). Partly due to the rain, a hard ground alarm [ALM] was received on Direct Current (DC) Motor Control Center [MCC] 1F. To determine the location of the ground, station Electrical Maintenance technicians conducted ground fault tracing using a DC Scout ground test device.

At 2204 on September 2, 2012, when the DC Scout device was connected between the Balance of Plant (BOP) 125 Volts DC (VDC) battery [BTRY] 1F and station ground, the Emergency Reserve Auxiliary Transformer (ERAT) [XFMR] sudden pressure seal-in relay [RLY] (63SPX) sealed in causing both the ERAT and ERAT Static Var Compensator (SVC) to trip.

Immediately following the trip, the ERAT deluge system actuated and fire pumps [P] 'A' and 'B' started. Safety related 4160 kV Bus [BU] 1A1, which had been powered from the ERAT, momentarily lost power and transferred to the Reserve Auxiliary Transformer (RAT). Due to the momentary loss of power to Bus 1A1, Fuel Building Ventilation [VG] lost power and its dampers [DMP] closed causing a loss of Secondary Containment differential pressure. Secondary Containment differential pressure increased above the 0.25 inches vacuum required by Technical Specification (TS) 3.6.4.1, Secondary Containment. Due to high secondary containment differential pressure, operators entered Emergency Operating Procedure (EOP) - 8, Secondary Containment Control. Fuel Pool Cooling and Cleanup [DA] system pump 'A' tripped, causing the upper containment pool level to drop. However, upper containment pool level did not drop below the minimum level required by plant TS 3.6.2.4, Suppression Pool Makeup System. The Drywell fission product monitor [MON] required by TS 3.4.7, Reactor Coolant System Leakage Detection Instrumentation, isolated. Main Control Room Ventilation [VI] 'A' chiller [CHU] shut down. Diesel Generator [DG] Vent Oil Room 1A Exhaust Fan [FAN] lost power. Several radiation monitors momentarily lost power and were declared inoperable.

Secondary Containment differential pressure was restored at 2219 on September 2, 2012, when the Standby Gas Treatment System SGTS [BH] was manually started and operators exited EOP - 8 at 2238 on September 2, 2012. The fission product monitor was restored by 2309 on September 2,

NRC FORM 366A (10-2010) **LICENSEE EVENT REPORT (LER) CONTINUATION SHEET** U.S. NUCLEAR REGULATORY COMMISSION

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REV NO.	
Clinton Power Station, Unit 1	05000461	2012	- 001 -	00	3 OF 4

NARRATIVE

2012, within the 30 day TS completion time. The Main Control Room Ventilation 'A' Chiller was restarted at 2237. The DG Vent Oil Room 1A Fan was restarted at 0104 on September 3, 2012.

Since the secondary containment differential pressure was greater than the TS required pressure, this event was reported (Event Number: 48269) on September 3, 2012, at 0417 as a condition that could have prevented the fulfillment of a safety function per 10 CFR 50.72(b)(3)(v)(C).

Corrective action program Issue Report 1408282 was initiated to evaluate this event.

A review of the ERAT trip and of the 1A1 Bus fed breaker logic indicates that the DC Scout signal used during ground fault tracing actuated the sudden pressure relay logic which then actuated the lockout relays. One lockout relay specifically blocks the synchro-verifier relay logic, thus blocking a fast transfer. This resulted in an automatic slow 1A1 bus transfer from the ERAT to the RAT. The slow transfer resulted in the momentary loss of power on the 1A1 bus and all downstream loads.

During troubleshooting activities for this event, a latent design error was identified on seal-in relays 63SPX and 63FPX. Both relays are Qualitrol Model 909-200-01 AC/DC Seal-In Relays with 125 VDC supply power. The latent design error is a ground wire installed on terminal 13 of the relay. The current vendor manual information states that terminal 13 should not be connected to earth ground when a DC power supply is used. The vendor has acknowledged that spurious operation can occur when this device is used with DC supply power and a ground on terminal 13. All indications show that the latent error has existed since original transformer construction at the factory in 1998. The current ERAT was received and installed in 1998.

C. CAUSE OF EVENT

The cause of this event was due to a latent design error that involved the wiring of terminal 13 to ground for the sudden pressure seal-in relay cards (63SPX). Updated vendor manual information states that terminal 13 should not be connected to earth ground when a DC power supply is used. The relay manufacturer has acknowledged that spurious operation can occur when this device is used with DC supply power and a ground on terminal 13. The latent error has existed since original transformer construction at the factory.

D. SAFETY CONSEQUENCES

There were no actual nuclear safety consequences related to this event. This event resulted in the loss of secondary containment for approximately 15 minutes, from 2204 to 2219 on September 2, 2012 due to loss of power to the Fuel Building ventilation system and dampers closing. Secondary Containment differential pressure was greater than the 0.25 inches vacuum required by TS 3.6.4.1. The SGTS was manually started during this period and differential pressure was restored to within limits. The SGTS initiates automatically when conditions indicate a release of radioactive material or a loss of coolant accident to ensure that any radioactive materials that leak from the Primary Containment into the Secondary Containment following an accident are filtered by SGTS prior to release to the environment.

NRC FORM 366A (10-2010)

LICENSEE EVENT REPORT (LER) U.S. NUCLEAR REGULATORY COMMISSION
CONTINUATION SHEET

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REV NO.	
Clinton Power Station, Unit 1	05000461	2012	- 001 -	00	4 OF 4

NARRATIVE

This event is considered to be reportable as a loss of safety function under 50.72(b)(3)(v)(C) and 50.73(a)(2)(v)(C) as an event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to control the release of radioactive material.

E. CORRECTIVE ACTIONS

A Temporary Modification under Engineering Change (EC) 390386 was implemented to disable the 63SPX (Qualitrol Model No. 909-200-01) trip function and remove the ground connection from terminal 13 on the seal-in relays (63SPX and 63FPX). The trip function of the 63SPX relay can be restored during the next ERAT maintenance outage. Based on these actions the risk of an invalid ERAT trip has been mitigated.

F. PREVIOUS OCCURRENCES

12/18/2001 - ERAT TRIP - The ERAT and ERAT SVC tripped (with deluge). A Root Cause investigation was performed. The cause of the trip was an internal fault. The cause for the internal fault on the ERAT was a gradual localized breakdown of the insulating oil due to corona discharge from the spliced HV lead. The controller cards, seal-in relays, etc., were not mentioned as contributing factors and no specific issues with the seal-in relays were documented.

3/02/2002 - ERAT TRIP - The ERAT and ERAT SVC tripped (with deluge). The cause of the trip was determined to be a wet seal-in relay card. The control cabinet contained gaps that allowed rain and subsequent deluge water to enter the cabinet. A Work Request was issued to seal the ERAT control cabinet.

G. COMPONENT FAILURE DATA

Manufacturer	Nomenclature	Manufacturer Model Number
Qualitrol Corporation	Sudden pressure Seal-in relay (63SPX)	909-200-01

Clinton Unit 1 **2013-12-08 8:36 PM** **#308766**

Failure of a Dry Type Transformer Results in a Loss of Power to Division 1 Vital 480VAC Buses and Plant Shutdown

Significance: Noteworthy - Consequential
This event is Noteworthy because the reactor was manually scrammed following a loss of instrument air to the containment and scram pilot air header following a transformer fault. It is Consequential because it resulted in lost generation.

Abstract:
Failure of a 4kV/480V dry type transformer caused a loss of power to Division 1 480V buses and resulted in a manual plant shutdown. The most probable cause of the transformer failure is a turn to turn failure of the high side windings due to insulation breakdown over time.

Event Summary:
On 12/08/2013 while Clinton Power Station (CPS) operating at rated electrical power, a fault on 0AP05E2 transformer inside Division (Div) 1 480V switchgear panel caused the upstream 4kV circuit breaker (1AP07EJ) to trip open on instantaneous overcurrent and resulted in a loss of power to Div 1 480V A and A1 buses fed by 1AP07EJ circuit breaker. The plant was manually shut down due to loss of instrument air to the containment and scram pilot air header after Div 1 containment instrument air valves had closed upon a loss of power to the solenoid valves. The failed transformer was inspected and found having damage to the A and B phase windings. There was no sign of tracking on the high voltage terminations or lightning arrestors. An Engineering Change (EC 396366) was developed to utilize a spare transformer in cabinet 0AP05E7 at the other end of the panel. Maintenance personnel performed necessary work to transfer leads, cables, conduit, etc. from the 0AP05E2 transformer to the 0AP05E7 transformer. After the 0AP05E7 transformer was energized, the station restored Div 1 480V buses to service and restarted the unit. (IR 1594407)

Cause Summary:
A definitive root cause cannot be determined until the failed transformer is removed and a failure analysis is completed. Based on the visual inspection and discussion with ABB, the most probable cause of the transformer failure is a turn to turn failure of the high side windings due to insulation breakdown over time.

Corrective Action Summary:
Corrective Action Summary:
The 1AP07EJ circuit breaker was thoroughly inspected and tested to verify it was not damaged by the fault.
The protective relays were calibrated and verified to operate correctly.
A spare dry type transformer in cabinet 0AP05E7 at the other end of the panel was utilized after it was inspected and tested with acceptable results to replace the failed transformer.
A Special Plant Condition (SPC) action has been created to track the removal of the failed transformer and failure analysis.

Browns Ferry Unit 2 **2014-04-11 10:41 PM** **#311418**

Inadvertent Trip of Condensate Booster Pump Breaker

Significance: Noteworthy - Consequential

This event is Noteworthy because a human performance error resulted in a the tripping of an in-service condensate booster pump. It is Consequential because a power reduction was required to restore the pump to service.

Abstract:

While attempting to rack out the 2B Condenser Circulating Water (CCW) Pump breaker the 2B Condensate Booster Pump (CBP) breaker was tripped resulting in a potential personnel injury due to opening a 4KV Breaker under load. The cause was determined to be ineffective use of human performance tools self check and flagging. The consequence was the condensate booster pump was tripped and reactor power had to be reduced to 94% in order to place the pump back in-service.

Event Summary:

The 2B Condenser Cooling Water (CCW) Pump was being restored after traveling water screen maintenance. When the 2B CCW pump handswitch (HS) was taken to start, the pump did not start due to the feeder breaker failing to close. The Unit 2 (U2) Turbine Building (TB) Assistant Unit Operator (AUO) was directed to inspect the breaker for any abnormal indications such as relay flags, etc, that could have prevented the breaker from operating. The inspection revealed no indications that would have prevented the 2B CCW pump breaker from closing. The Outside AUO was notified to inspect for any abnormal conditions locally at the 2B CCW pump. The Outside AUO reported back that all conditions were normal. The U2 TB AUO was directed to rack the 2B CCW Pump breaker out and inspect the breaker, fuses and to perform a test of the breaker. The U2 TB AUO obtained the procedure, safety equipment and a peer check and proceeded to perform the breaker rack out operation.

Once personnel and equipment were at the breaker location, the U2 TB AUO and peer checker commenced the breaker rack out procedure (0-GOI-300-2 section 5.27 Siemens 4160V horizontal Rack-out). The operators identified the correct breaker on the board. The U2 TB AUO had used the upper cabinet door as a technique in the past to flag a breaker which was about to be manipulated, but mistakenly shut the door as the peer checker began setting up the safety boundary. The U2 TB AUO turned around and made a phone call to the control room to let them know that he would be racking out the 2B CCW pump breaker and then donned the 100 calorie coveralls (arc flash suit) including the hood (with dark face shield) over his head. The operators hearing was impaired by the hood and hearing protection combined with an elevated noise level due to its proximity to the bus duct cooling fan. The breaker racking tool was on the floor in front of the 2B CBP breaker (next to the 2B CCW Pump Breaker). The U2 TB AUO went to the breaker that was in front of the breaker racking tool and began performing the procedure. The peer checker, who was stationed at the required position outside the flash zone, saw the performer addressing the incorrect breaker, but was unable to gain the attention of the performer of the performer. The 2B CBP tripped when the shutter was opened on the breaker to insert the racking tool. When the breaker was racked to the test position, the U2 TB AUO removed the hood and saw that he was on the 2B Condensate booster pump breaker. The AUOs immediately called the control room to let them know. Reactor power, pressure, and level did not change.

Cause Summary:

Apparent Cause: Ineffective use of human performance tools self check and flagging.

Contributing Cause: Failure to establish a consistent peer check / robust flagging method to use during breaker racking operations on medium voltage (and greater) switchgears and communicate the expectation for use of the method to the operators

Corrective Action Summary:

Develop a Training Needs Analysis (TNA) to determine the need to train the operators on acceptable techniques when racking switchgears once a consistent method of implementation has been developed.

Develop a consistent peer check / robust flagging method to use during breaker racking operations on medium voltage (and greater) switchgears and communicate the expectation for the use of the method to the operators.

Incorporate the consistent peer check / robust flagging method to use during breaker racking operations on medium voltage (and greater) switchgears into General Operating Instruction 0-GOI-300-2, Electrical, to maintain sustainability of the method.

Obtain switchgear flagging tools and evaluate for implementation of the best tool.

Conduct a review of industry options for an Arc Flash transition lens for the 100 cal suit hood that could be used at BFN to improve visibility when in use.

Conduct a review of 0-GOI-300-2, Electrical, to identify procedural enhancements to improve peer check order.

Perform Flagging Observation Blitz and Trending.

Clinton Power Station
8401 Power Road
Clinton, IL 61727

Exelon Generation.

U-604354
July 5, 2017

10CFR50.73
SRRS 5A.109

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: Licensee Event Report 2017-002-01

Enclosed is Licensee Event Report (LER) 2017-002-01: Failure of the Division 1 Diesel Generator Ventilation Fan Load Sequence Relay Circuit During Concurrent Maintenance of RHR Division 2 Results in an Unanalyzed Condition. This is the supplemental report to LER 2017-002-00 submitted to the NRC on May 4, 2017. The updated information in the LER is denoted by revision bars located in the right-hand margin. This report is being submitted in accordance with the requirements of 10 CFR 50.73. There are no regulatory commitments contained in this report.

Should you have any questions concerning this report, please contact Mr. Dale Shelton, Regulatory Assurance Manager, at (217) 937-2800.

Respectfully,

BRADLEY T. KAPELLAS FOR TED STONER

Theodore R. Stoner
Site Vice President
Clinton Power Station

KP/bsz

Attachment: Licensee Event Report 2017-002-01

cc:

Regional Administrator— NRC Region III
NRC Senior Resident Inspector - Clinton Power Station
Office of Nuclear Facility Safety — Illinois Emergency Management Agency

IE22
NRR

NRC FORM 366 (04-2017) U.S. NUCLEAR REGULATORY COMMISSION | APPROVED BY OMB: NO. 3150-0104 EXPIRES: 03/31/2020

LICENSEE EVENT REPORT (LER)

(See Page 2 for required number of digits/characters for each block)

(See NUREG-1022, R.3 for instruction and guidance for completing this form http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1022/r3/)

Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Information Services Branch (T-2 F43), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by e-mail to Infocollects.Resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Clinton Power Station, Unit 1	05000461	1 OF 4

4. TITLE

Failure of the Division 1 Diesel Generator Ventilation Fan Load Sequence Relay Circuit During Concurrent Maintenance of RHR Division 2 Results in an Unanalyzed Condition

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
										05000
03	09	17	2017	- 002	- 01	07	07	2017	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 089

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☒ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
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☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☒ 50.73(a)(2)(v)(D)	☐ 73.77(a)(2)(i)
☐ 20.2203(a)(2)(vi)	☒ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(vii)	☐ 73.77(a)(2)(ii)
	☐ 50.73(a)(2)(i)(C)	☐ OTHER Specify in Abstract below or in NRC Form 366A	

12. LICENSEE CONTACT FOR THIS LER

LICENSEE CONTACT	TELEPHONE NUMBER (Include Area Code)
Dale A. Shelton, Regulatory Assurance Manager	217-937-2800

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

14. SUPPLEMENTAL REPORT EXPECTED	15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES (If yes, complete 15. EXPECTED SUBMISSION DATE) ☒ NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On Tuesday, March 7, 2017 at 2259 CDT, an Equipment Operator detected a relay cycling every 10 seconds from the Division (Div.) 1 480V Unit Substation (Sub) 1A. Agastat Time Delay Relay (TDR) 427X2-41A (X2 relay) was determined to be the source of the clicking sound. The X2 relay supports the undervoltage load shed and restoration of the Div. 1 Emergency Diesel Generator (EDG) ventilation room fan 1VD01CA. The logic is designed to shed 1VD01CA on undervoltage, prevent it from restarting, then allow it to be restored 10 seconds after voltage is restored either by the EDG or return of the safety bus. An investigation of the relay cycling condition determined that 1VD01CA was unable to respond to a demand signal and the cycling was the effect of interaction between the X2 and 427X3-41A (X3) relays. As a result, Div. 1 EDG was declared inoperable on March 9. With the Div. 2 Residual Heat Removal (RHR) System already inoperable due to scheduled maintenance, the plant was determined to be in an unanalyzed condition. A causal analysis determined that not understanding the design basis of the circuit subject to relay coordination and the impact of the change in specific components as part of a 2008 design change was the cause of the condition. Corrective actions included the replacement of the X3 relay with the original design relay. Div. 2 RHR was returned to service on March 8. Subsequently, Div. 1 EDG was restored to OPERABLE on March 11. This is reportable as an unanalyzed condition, operation prohibited by the Technical Specifications and a loss of safety function.

NRC FORM 366 (04-2017)

NRC FORM 366A (04-2017) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) CONTINUATION SHEET

(See NUREG-1022, R.3 for instruction and guidance for completing this form http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1022/r3/)

APPROVED BY OMB: NO. 3150-0104 EXPIRES: 03/31/2020

1. FACILITY NAME	2. DOCKET NUMBER	3. LER NUMBER YEAR	SEQUENTIAL NUMBER	REV NO.
Clinton Power Station	05000461	2017	- 002	- 01

NARRATIVE

PLANT AND SYSTEM IDENTIFICATION

General Electric—Boiling Water Reactor, 3473 Megawatts Thermal Rated Core Power
Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

EVENT IDENTIFICATION

Failure of the Division 1 Diesel Generator Ventilation Fan Load Sequence Relay Circuit During Concurrent Maintenance of RHR Division 2 Results in an Unanalyzed Condition

A. Plant Operating Conditions before the Event

Unit: 1	Event Date: March 9, 2017	Event Time: 0319
Mode: 1	Mode Name: Power Operation	Reactor Power: 99 percent

B. DESCRIPTION OF EVENT

On March 7 at 2258, an area operator detected a "clicking sound" coming from safety related Unit Substation 1A (1AP11E). The sound was determined to be emanating from relay 427X2-41A (X2 relay) which was cycling every ten (10) seconds. The model of this component is an Agastat Time Delay Relay (TDR) that provides the signal to reset the Load Shed and Resequencing circuit for Div. 1 Emergency Diesel Generator (EDG) Room Vent fan 1VD01CA. Div. 1 EDG was declared inoperable on March 9 when it was determined that 1VD01CA was unable to respond to a demand signal.

An event investigation determined that relay 427X3-41A (X3 relay) in the undervoltage circuitry for 1AP11E was not operating as expected, causing the cycling of the X2 relay. The effect of this condition was that (1) the associated Fan 1VD01CA would be unable to start automatically or manually when required, and (2) the ability of the Div. 1 fan to properly sequence following restoration from a bus undervoltage condition was impacted. During an assessment of relay replacement history, it was established that the X3 relay which was originally an ITE Gould J13 relay had been replaced with a General Electric CR120B relay in 2008. The replacement X3 relay combined with the installed X2 relay satisfactorily passed post maintenance testing in 2008 (including undervoltage functional testing) and also passed integrated surveillance testing in 2009. A "like-for-like" replacement of the X2 relay was performed in 2011 and passed integrated surveillance testing in 2011 and 2013. The investigation determined, however, that the combined operating characteristics of the X3 and X2 relays was adversely impacted by a

NRC FORM 366A (04-2017) U.S. NUCLEAR REGULATORY COMMISSION		APPROVED BY OMB: NO. 3150-0104 EXPIRES: 03/31/2020		
LICENSEE EVENT REPORT (LER) CONTINUATION SHEET (See NUREG-1022, R.3 for instruction and guidance for completing this form http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1022/r3/)		Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Information Services Branch (T-2 F43), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by e-mail to Infocollects.Resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.		
1. FACILITY NAME	2. DOCKET NUMBER	3. LER NUMBER		
		YEAR	SEQUENTIAL NUMBER	REV NO.
Clinton Power Station	05000461	2017	- 002	- 01

NARRATIVE

second "like-for-like" replacement of the X2 relay in May 2016. Through an error in work order planning, no testing was specified for this "like-for-like" replacement. However, the impact on the operating characteristics of the electrical circuit for this X2 replacement would not have been detected by the procedurally required post maintenance testing. Due to the successful integrated testing since 2008, variations in the dropout voltage and associated impacts of the relays used in this circuit had not been previously recognized.

The combination of replacement of the X3 (ITE Gould J13) relays with CR120B relays in 2008 and the perceived "like-for-like" replacement of the Agastat X2 relay in May 2016 established a relay coordination condition where the required relay sequence of operation was adversely affected due to variations in the manufacturer's electrical characteristics of the relays supplied for the electrical circuit. The cause of the event was attributed to not understanding the design basis of the circuit subject to relay coordination and the impact of the change in specific components as part of the 2008 design change.

Following the replacement of the CR120B relay with the original ITE Gould J13 relay design and successful undervoltage testing, the Div. 1 EDG was restored to OPERABLE status.

C. CAUSE OF EVENT

The cause of the event was attributed to not understanding the design basis of the circuit subject to relay coordination and the impact of the change in specific components as part of a 2008 design change. Since the critical characteristics of the EDG ventilation fan logic were not clearly documented or known, it was assumed that differences in relay dropout voltages were not material to the design function.

D. SAFETY ANALYSIS

There were no actual safety consequences associated with the event described in this report since offsite power remained available during the event and no other events occurred necessitating ECCS actuation. Plant systems necessary to conduct a safe and orderly shutdown remained available during this event. The Division 2 EDG, although inoperable intermittently to perform required surveillance testing would have been able to be restored expeditiously in the event of an accident in conjunction with a loss of offsite power.

NRC FORM 366A (04-2017) Page 3 of 4

NRC FORM 366A (04-2017) U.S. NUCLEAR REGULATORY COMMISSION		APPROVED BY OMB: NO. 3150-0104 EXPIRES: 03/31/2020		
LICENSEE EVENT REPORT (LER) CONTINUATION SHEET (See NUREG-1022, R.3 for instruction and guidance for completing this form http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1022/r3/)		Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Information Services Branch (T-2 F43), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by e-mail to Infocollects.Resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.		
1. FACILITY NAME	2. DOCKET NUMBER	3. LER NUMBER		
		YEAR	SEQUENTIAL NUMBER	REV NO.
Clinton Power Station	05000461	2017	- 002	- 01

NARRATIVE

The event is reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) as a condition which was prohibited by the plant's Technical Specifications. This event is also reportable in accordance with 10 CFR 50.73(a)(2)(ii)(B) as a condition that resulted in the plant being in an unanalyzed condition that significantly degraded plant safety. Additionally, a review of plant logs identified occurrences when the Div. 2 EDG was made inoperable to support surveillance testing during this time period. As a result, this event is also reportable as a loss of safety function per 10 CFR 50.73 (a)(2)(v)(D) which is considered a safety system functional failure.

E. CORRECTIVE ACTIONS

The corrective actions taken include replacing the existing CR120B relay with an original ITE Gould J13 relay design and successfully performing the undervoltage test. A circuit modification is in progress that will eliminate the vulnerability to the lower dropout voltage settings expected from use of the CR120B relays. A procurement engineering standard will be developed to address complex relay logic schemes and what critical characteristics should be selected for evaluation when performing a safety basis, a commercial grade dedication, and/or item equivalency evaluation for complex circuits involving relay coordination.

F. PREVIOUS SIMILAR OCCURENCES

No previous occurrences involving similar circuits and relay interactions have been identified.

G. COMPONENT FAILURE DATA

No CPS component failures associated with this event were identified.

NRC FORM 366A (04-2017)

Page 4 of 4

IR 01465692 – ERAT SERVERON SERVICE LIGHT ON

AR 01465692 Report

Aff Fac:	Clinton	**AR Type:**	CR	**Status:**	COMPLETE
Aff Unit:	01	**Owed To:**	A5150NSCAP	**Due Date:**	02/22/2013
Aff System:	AE			**Event Date:**	01/23/2013
CR Level/Class:	4/D			**Disc Date:**	01/23/2013
How Discovered:	H02			**Orig Date:**	01/23/2013
WR/PIMS AR:	00422859	**Equip Tag:**	-		

Action Request Details

Subject: EOID ERAT SERVERON SERVICE LIGHT ON

Description:

Operable Basis:
Blue service light on the Serveron being ON is not indicative of a degraded or non-conforming condition associated with the Emergency Reserve Aux Transformer that would reasonably prevent fulfillment of the off-site source safety function in support of ITS LCO 3.8.1. The ERAT and ERAT SVC continue to provide required voltage and frequency and remain OPERABLE per ITS LCO 3.8.1.

RTK 1/23/2013: Reference IR's : IR 1465222, IR 1465696 and, IR 1465219.
Discussed this information with the System Manager and the following is noted: The MPT A/B/C, UAT A/B, RAT A/B/C, and ERAT were walked down by the System Manager on 1/23/2013 at approximately 9:30 AM. The System Manager only found RAT A and RAT C Serveron Blue Service Lights on. All of the other transformers Serveron units did not have the service lights on. At 4:30PM the system manager performed a walkdown of RAT A and C and found the service lights had extinguished. Serveron support personnel were contacted. Per Serveron, "If the oil temperature at the point of extraction is below 0C or above 60C, the pump will stop because the oil is either too viscous or too hot. The service light will come on in this condition if the monitor is not able to make any sample runs for this issue over a 24 hour period. Once the temperature falls back into the proper range, the oil pump will resume operation." Once the monitor makes a successful sample run, the service light will extinguish. This was confirmed by looking at the last sample runs prior to the IRs being initiated. For RAT A/B/C and the ERAT the oil temperature was respectively 0.1C, -2.4C, 0.2C, and -0.4C. Confirmation that the Service Light will clear once a successful run is taken was given by RAT B Serveron. The monitor sampled this morning at approximately 6AM and found the oil temperature to be 5.1C. When the system manager performed a walkdown at 9:30 AM the service light was extinguished. At 4:30PM the system manager performed a walkdown and both RAT A and C service lights were extinguished and similar conditions were observed with the oil temperatures. In conclusion, as the ambient temperature remains low, the oil temperatures may drop below 0C and the monitors will not sample. If the ambient and oil temperatures stay consistently low for 24 hours straight when the monitor cannot sample, the Blue Service light will illuminate. Once the ambient temperature rises and the oil temperature rises above 0C, the monitor will sample and upon successful completion, the blue service light will extinguish.

OPEX - CPS LER 2017-010-00: Division 1 Transformer Failure Leads to Instrument Air Isolation to Containment Requiring a Manual Reactor Scram

A. Summary

On December 9, 2017 at 1347 CDT the Main Control Room received annunciators that indicated a trip of a 4160V 1A1 Breaker, the 480V transformer 1A and Al feed breaker. The loss of Division 1 480V power caused the instrument air (IA) containment isolation valves to fail close as designed. The loss of IA affected various containment loads, including the scram pilot air header and containment isolation valves. Another consequence of this event was that secondary containment differential pressure became positive due to fuel building ventilation dampers failing closed by design due to the loss of power. Operations entered Emergency Operating Procedure (EOP) -08, Secondary Containment Control, and Technical Specification (TS) Limiting Condition for Operation (LCO), 3.6.4.1 Action A.1. Division 2 Standby Gas Treatment System was activated at 1350 and restored secondary containment differential pressure within allowable TS values at 1351. The TS LCO and EOP were exited when allowable TS values were restored. Due to the loss of IA, a manual reactor scram was inserted at 1353 when two control rods began drifting in as expected. A phase to ground fault was identified on 480V transformer 1A (1AP11E). On December 14, the 480V transformer was replaced and the plant returned to Mode 1 operations on December 15.

The condition described in this report was determined to be reportable under 10 CFR50.73(a)(2)(iv)(A), 10 CFR 50.73(a)(2)(v)(C) and 10 CFR 50.73 (a)(2)(ii)(B). The cause of the transformer failure is currently under investigation and will be provided in a supplemental report. This event is classified as an unplanned scram with complications due to the loss of the Division 1 480V power.

B. Description of Event

At 1347 CDT on December 9, 2017, the Main Control Room received annunciators that indicated a trip of the 4160 V [EB] 1A1 breaker [BKR]1 APO7EJ and the loss of the 480V transformer 1A [ED] and Al. Numerous Division 1 components lost 480V power (powered from unit substations 1A and Al). The Division 1 containment Instrument Air isolation valves had failed closed by design due to the loss of power. Due to the loss of containment instrument air, several control rods began to drift into the core as expected and, by procedure, the reactor mode switch was placed in the shutdown position at 1353 and a manual reactor scram was performed.

Due to the loss of power, the Fuel Building ventilation dampers failed closed by design. With the normal ventilation system secured, secondary containment differential pressure rose to slightly greater than 0 inches water gauge which exceeded the Technical Specification Surveillance Requirement 3.6.4.1.1 limit of greater than or equal to 0.25 inches vacuum water gauge at 1348. The Control Room entered Emergency Operating Procedure-8, Secondary Containment Control. Secondary Containment differential pressure was restored within Technical Specification requirements at 1351 by starting the Division 2 Standby Gas Treatment System (SGTS).

Inspection of 480V transformer 1A (1AP11E) found an area on the upper end of the B phase coil that was consistent with a phase to ground fault. On December 14, the transformer was replaced and the plant returned to Mode 1 operations on December 15.

This event is reportable under 10 CFR 50.73(a)(2)(iv)(A) as a manual actuation of the Reactor Protection System (RPS), 10 CFR 50.73(a)(2)(v)(C) as a Condition that Could Have Prevented

OPEX - CPS LER 2017-010-00: Division 1 Transformer Failure Leads to Instrument Air Isolation to Containment Requiring a Manual Reactor Scram

Fulfillment of a Safety Function and 10 CFR 50.73 (a)(2)(ii)(B) as the plant being in an unanalyzed condition. The event described in this report is considered an unplanned scram with complications due to the loss of the Division 1 480V power.

C. Cause of the Event

A phase to ground fault was identified on the B Phase of the 480V transformer 1A (1AP11E). The cause of the transformer failure is currently under investigation and will be provided in a supplemental Licensee Event Report.

D. Safety Consequences

The trip of 4160V circuit breaker and the failure of the 480V transformer placed the station in a potential scram condition due to loss of instrument air to the containment and scram pilot air header. Manual operator actions were taken to shut down the reactor prior to an automatic scram and place the plant in a safe and stable condition. The loss of 480 volt power caused the Fuel Building Ventilation System to isolate resulting in positive secondary containment pressure. Operators placed the Division 2 SGTS in service to restore secondary containment negative pressure. All Division 2 and Division 3 Emergency Core Cooling Systems remained operable and available throughout this event for accident mitigation if required. No plant safety limits were exceeded and no Emergency Core Cooling System actuations occurred.

E. Corrective Actions

On December 14, the faulted transformer was replaced and the plant returned to Mode 1 operations on December 15. Additional corrective actions will be determined following completion of the causal evaluation.

F. Previous Similar Occurrences

LER 2013-008-01 Failure of Division 1 Transformer Leads to Isolation of Instrument Air Supply to Containment, Lowering Scram Pilot Air Header Pressure, and Manual Reactor Scram

On December 8, 2013 at 2026 hours with the plant in Mode 1 at 97.3 percent reactor power, operators received multiple alarms due to the trip of 4160 volt 1A1 breaker which resulted in a loss of power to two Division 1 480 volt unit substations. Operators were immediately dispatched and found a 4160/480 volt stepdown transformer AI (0APO5E) failed. Many Division I components lost power. The loss of power caused an instrument air (IA) containment isolation. The loss of IA affected various containment loads, including the scram pilot air header, the main steam isolation valves and the reactor water cleanup system. At 2036 hours, the scram pilot air header low pressure alarm was received and in response to an anticipated automatic reactor scram, operators immediately initiated a manual reactor scram. All control rods fully inserted into the core.

G. Component Failure Data

Component Description: I-T-E Dry Type Transformer; 4160V/480V; 750KVA
Manufacturer: GOULD-BROWN-BOVERI

Figure 1 – Offsite Sources

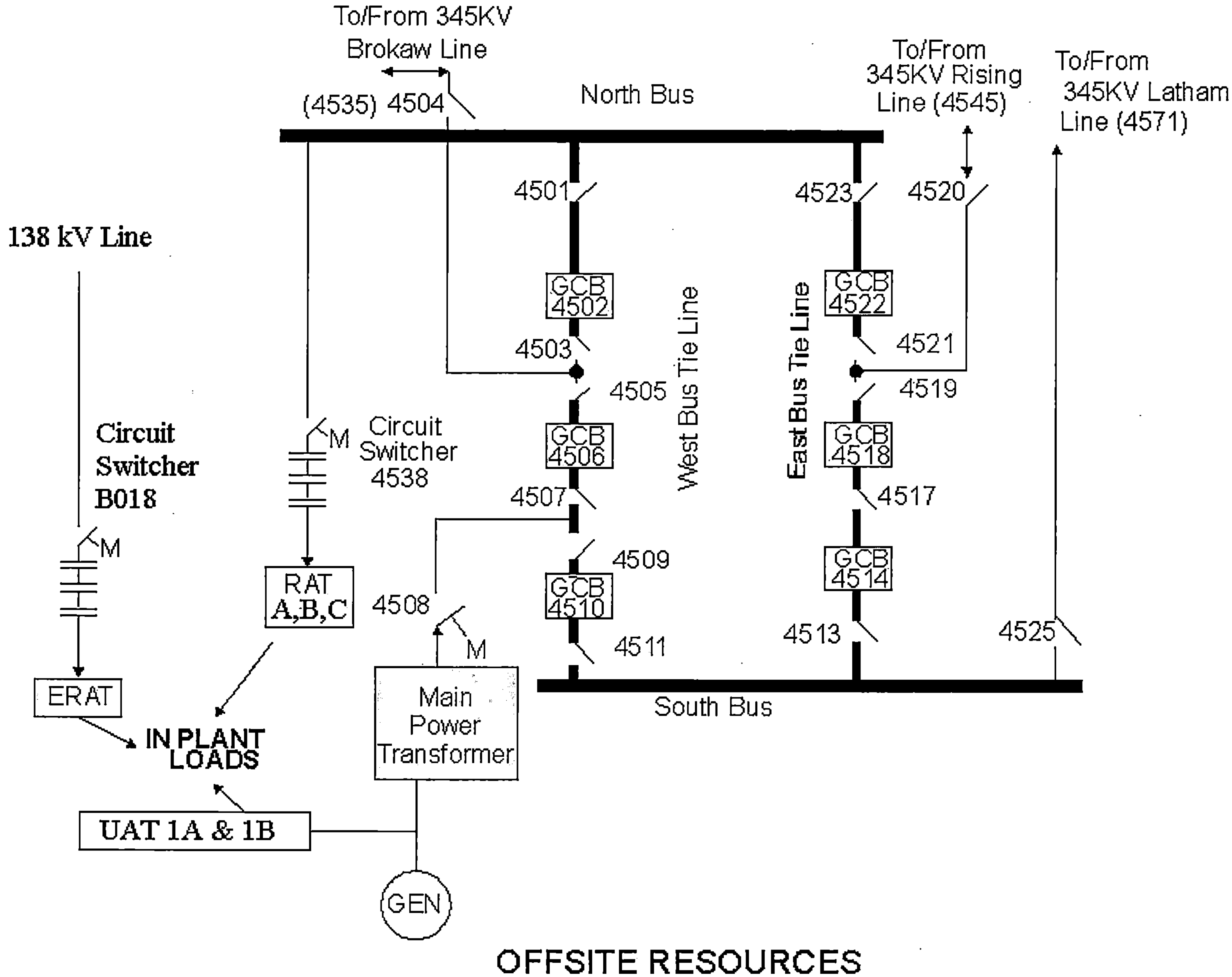
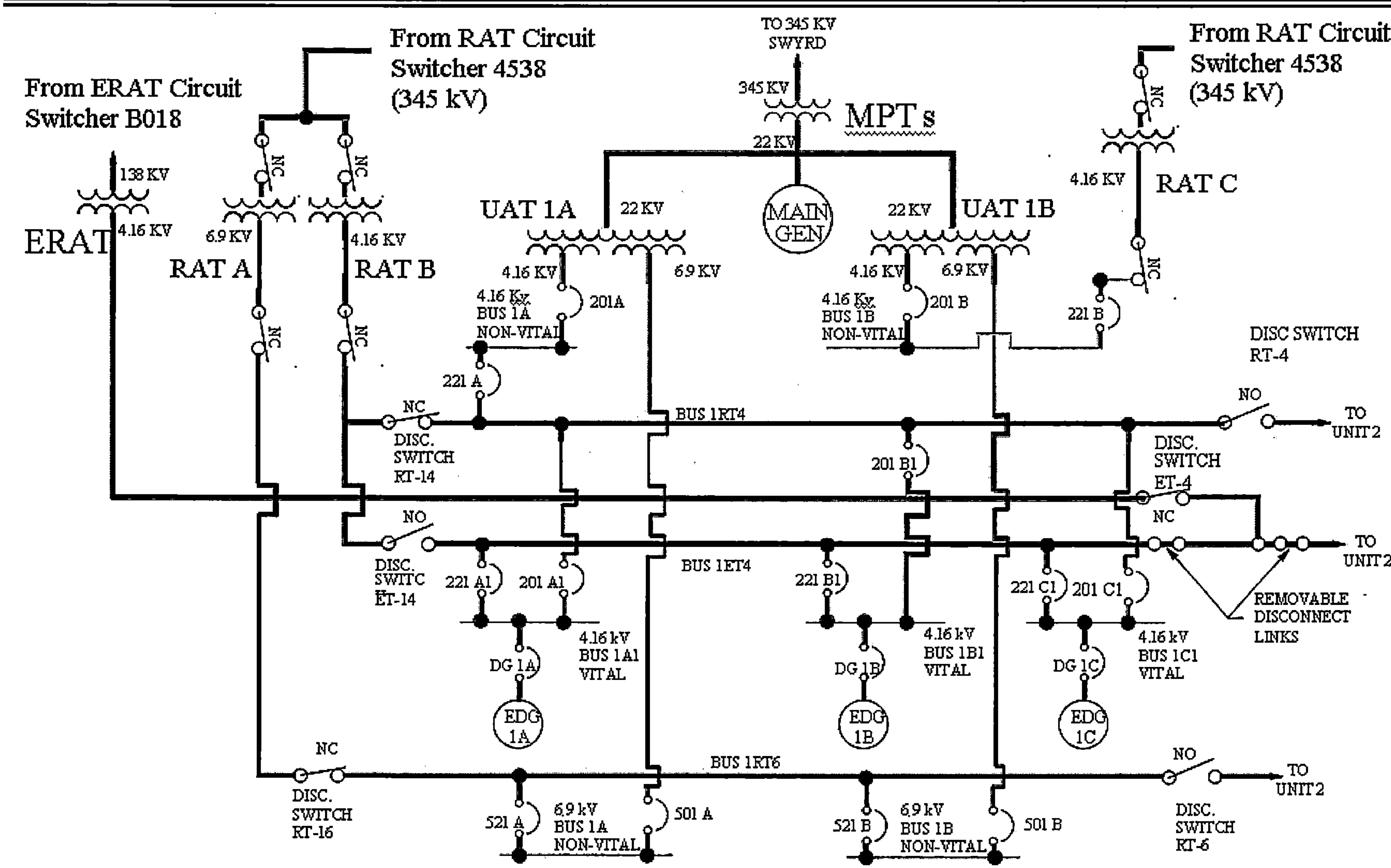
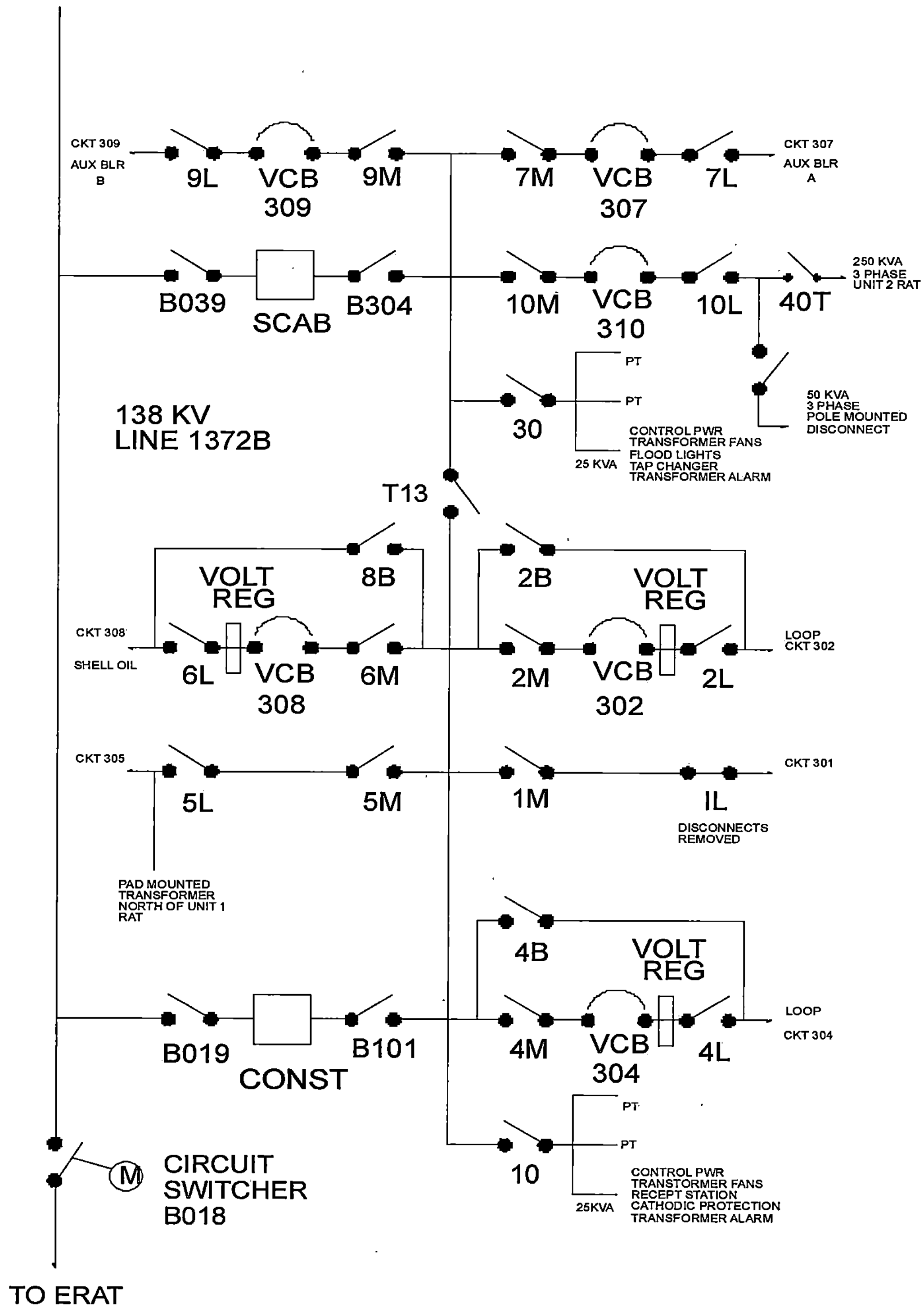


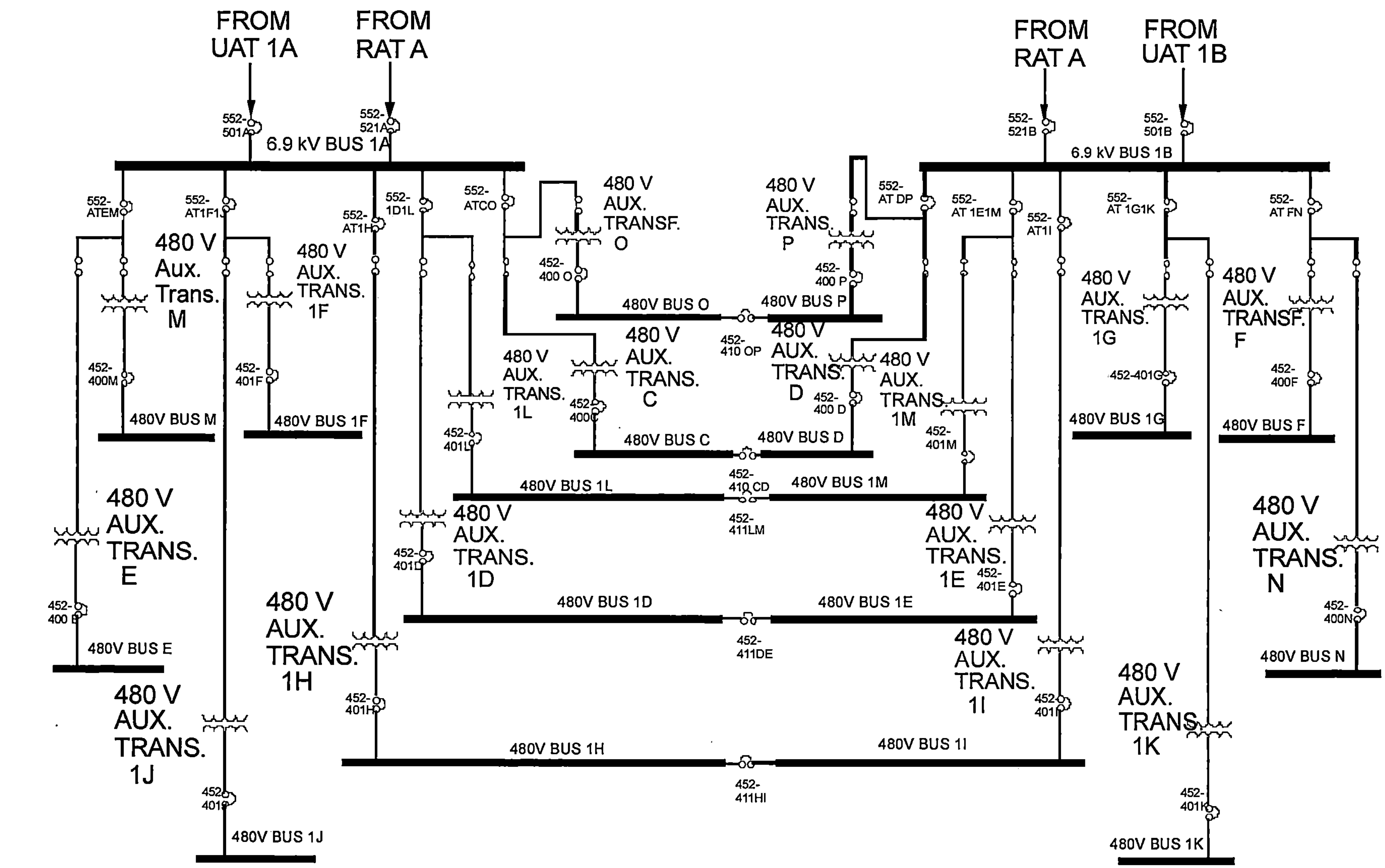
Figure 2 – Auxiliary Power System



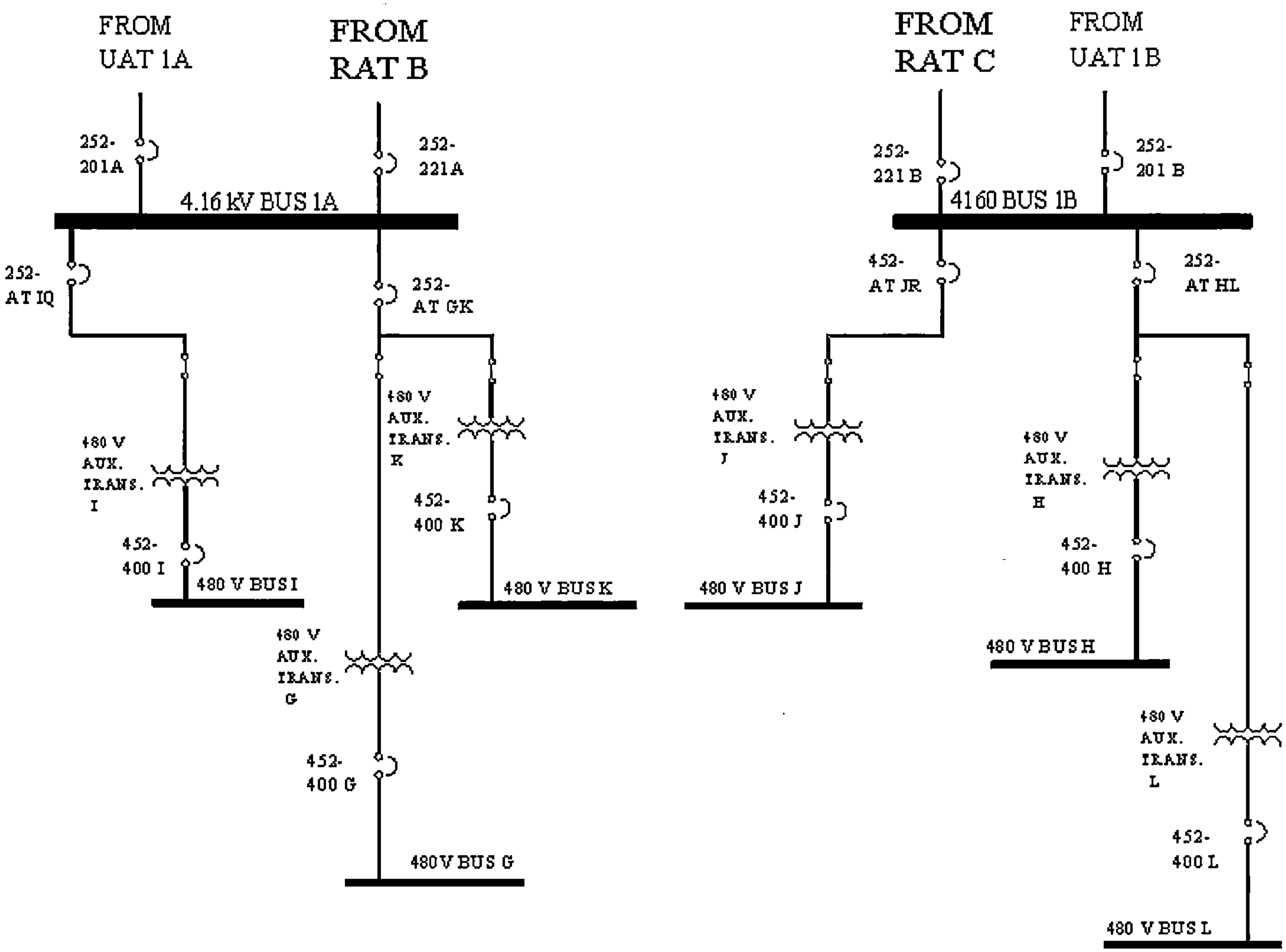


12kV SWITCHYARD

Figure 4 – 6.9 KV System



6.9 kV System



4.16kV System (Non-safety Related)

Figure 6 – 4.16 KV System (Safety Related)

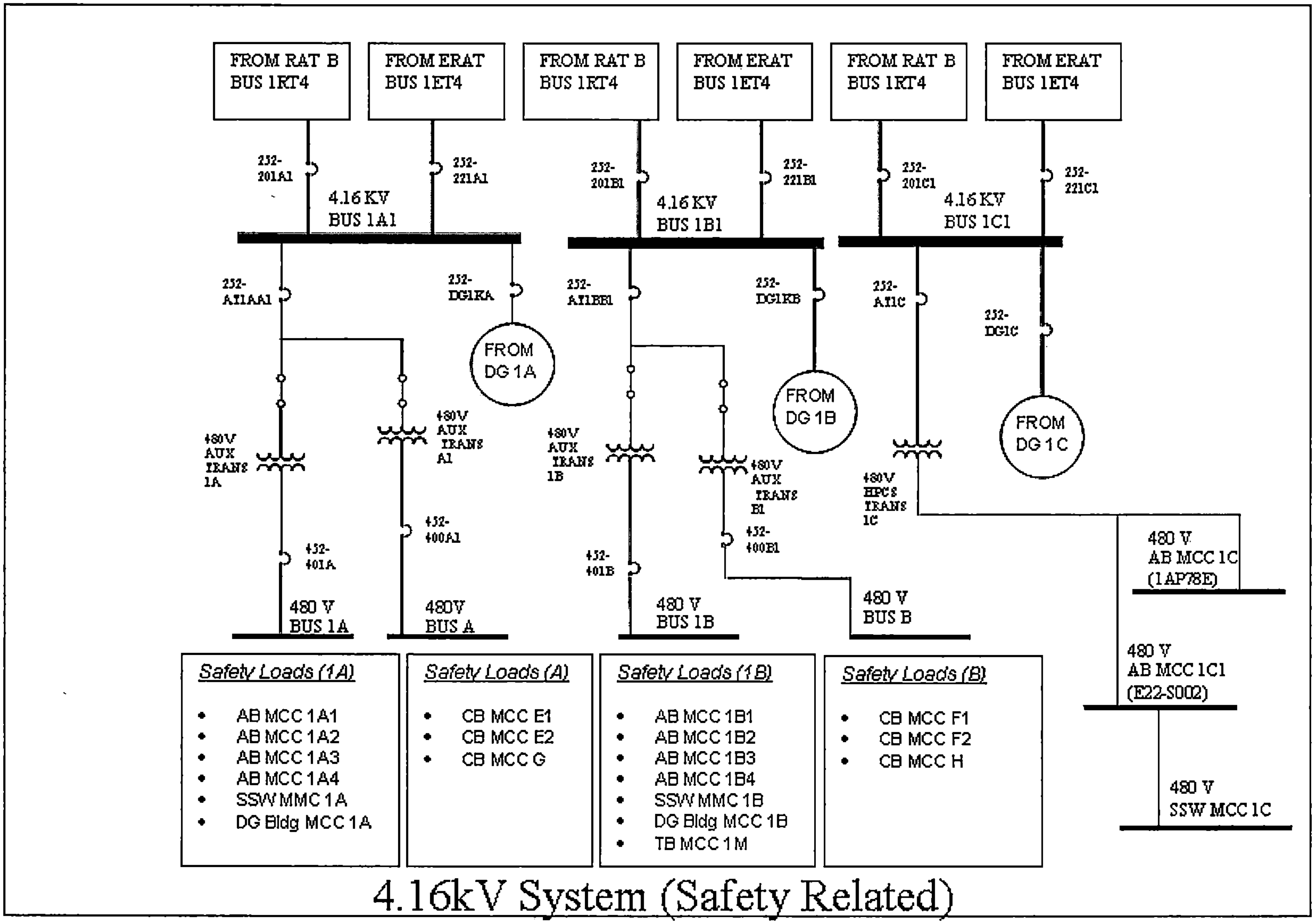
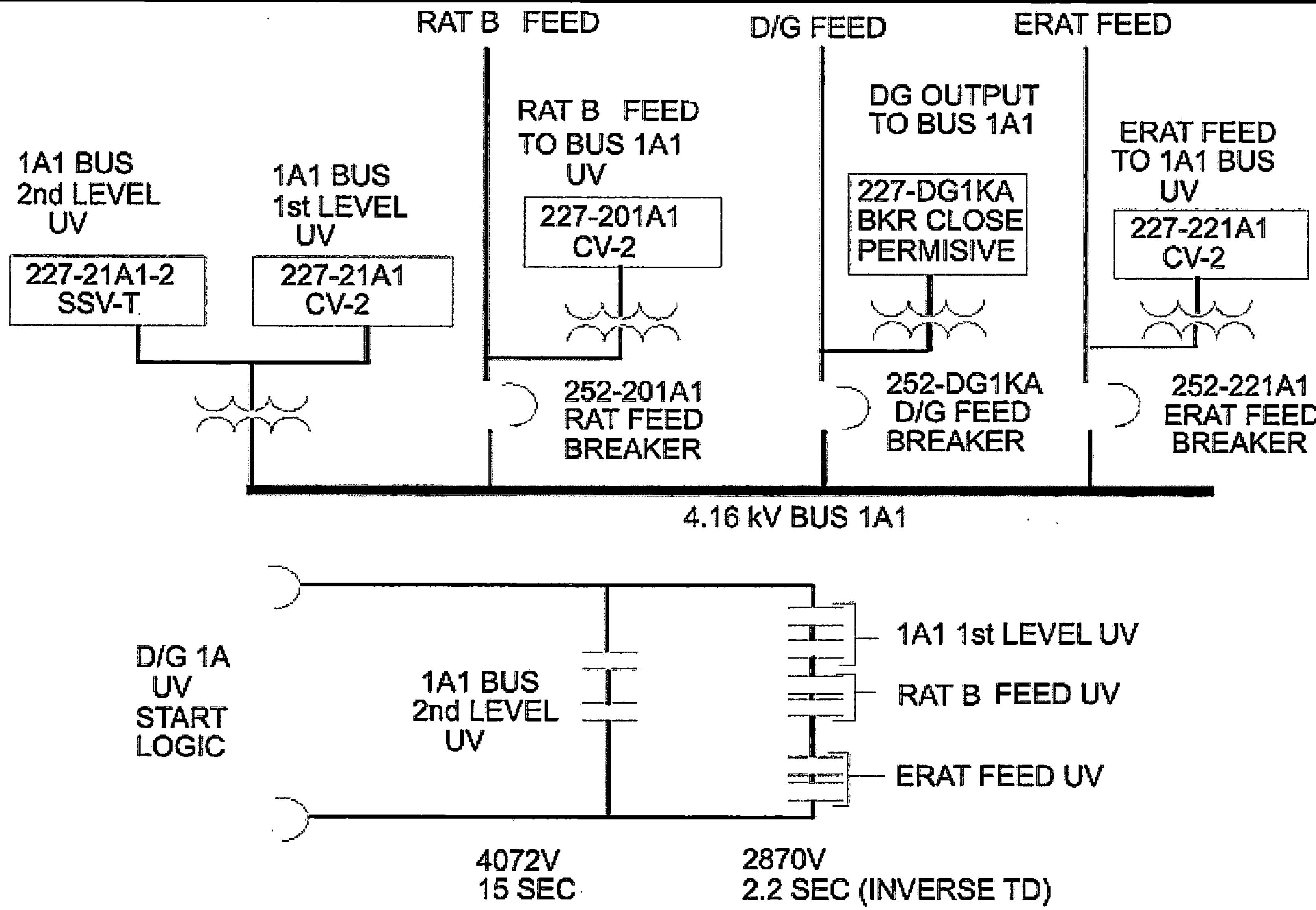
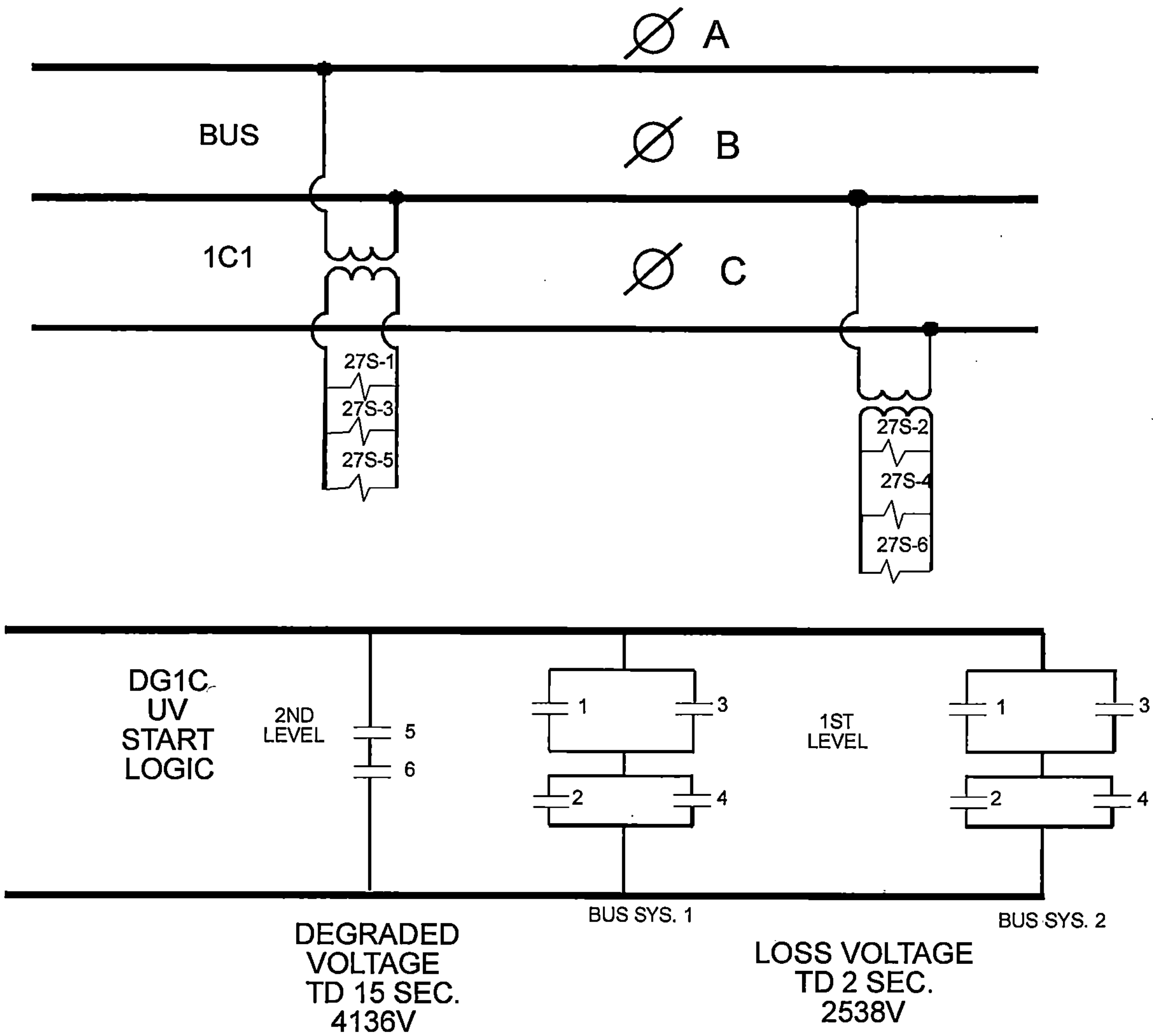


Figure 7 - 4.16 KV Bus 1A1 UV Sensors & DG UV Start Logic



4.16 kV BUS 1A1 UV SENSORs & D/G UV START LOGIC

Figure 8 - 4.16 KV Bus 1C1 UV Sensors & DG UV Start Logic



4.16kV BUS 1C1 UV SENSORS & DG UV START LOGIC

Figure 9 – Typical Auxiliary Power 4.16 & 6.9 KV Breaker Control Power Design

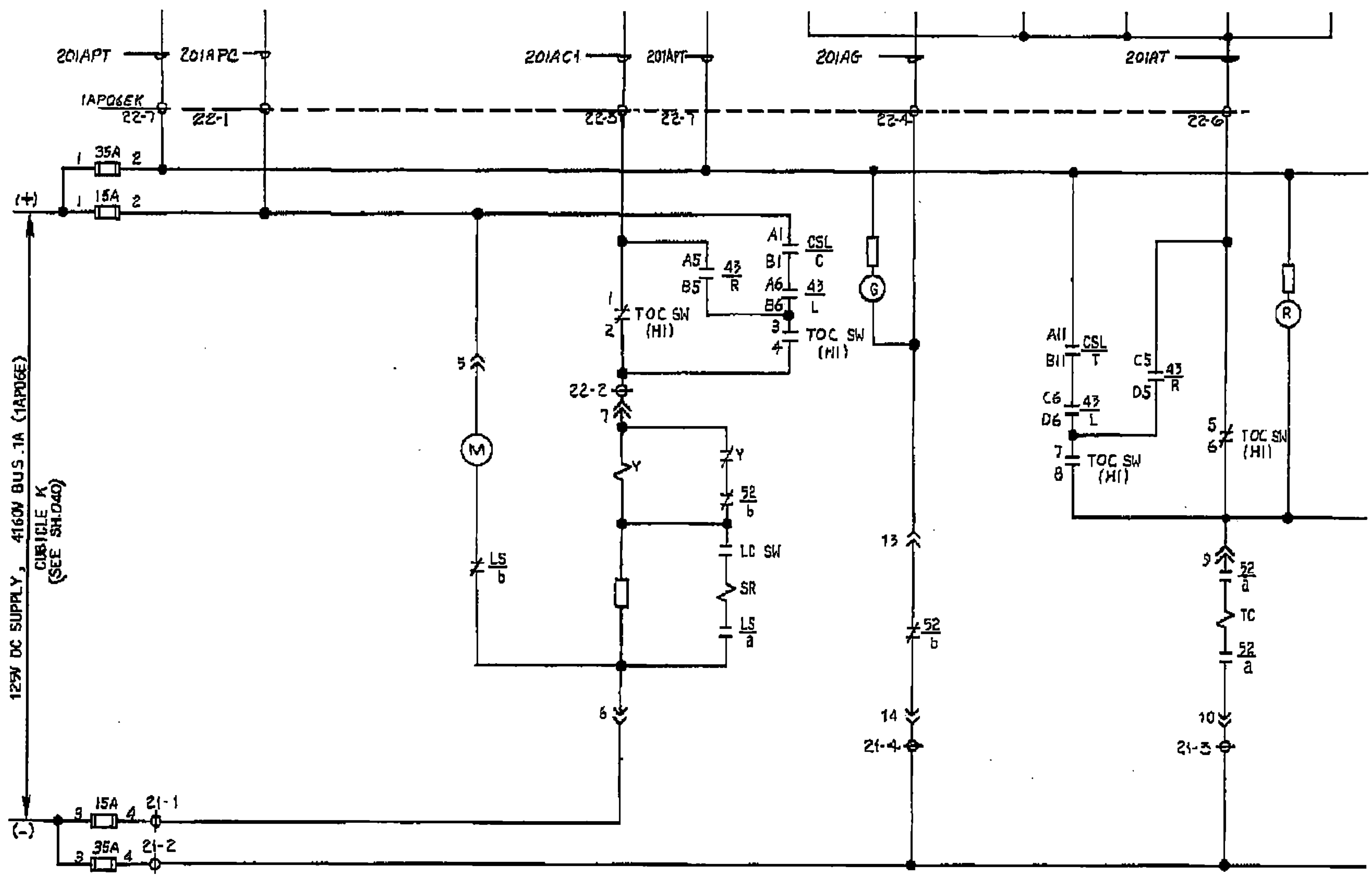
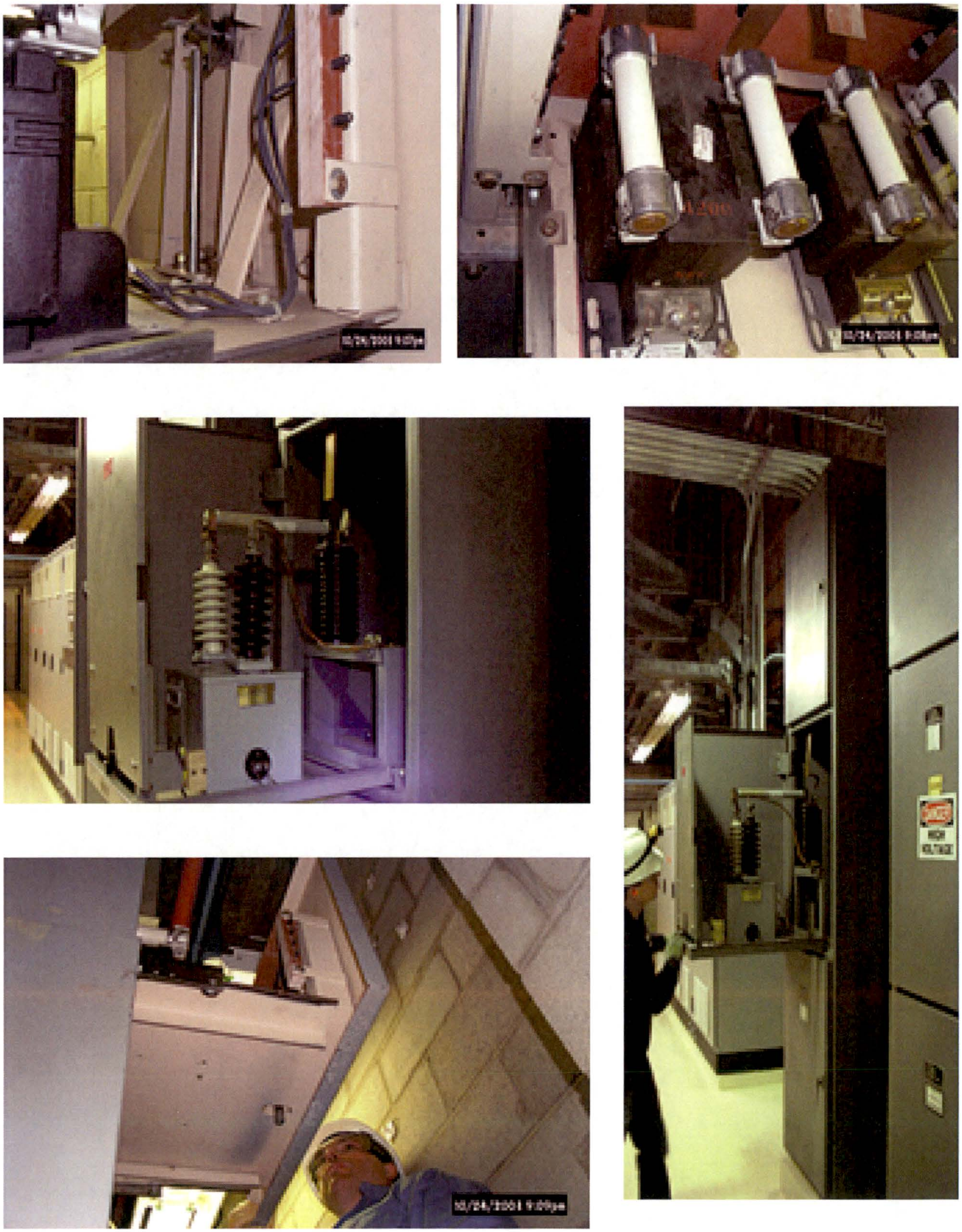


Figure 10 – Potential Transformer (PT) Cubicle Internals Examples



Course/Program:	ILT/NLO/LORT	Module/LP ID:	N-CL-OPS-264000
Title:	© Diesel Generator/Diesel Fuel Oil	Course Code:	N-CL-OPS-264000
Author:	Rick Jackson	Revision/Date:	006 05/16/17
Prerequisites:		Revision By:	Carl Leach
Responsible Site:	Clinton Power Station	Est. Teach Time:	6.0 hours

Qualified Nuclear Engineer Review (If applicable):	N/A	Date:	N/A
Training Supervision Review: (Print name / Signature)	R. J. Frederes /S/	Date:	06/06/17
Program Owner Approval: (Print name / Signature)	N/A - Minor Revision per TQ-AA-223	Date:	N/A

TABLE OF CONTENTS **Pg. #**

OBJECTIVES

Initial: From memory, unless otherwise stated, and with 100% accuracy, in accordance with the course reference materials and procedures, the trainee shall: be able to:

Continuing: Using normally available references, unless otherwise stated, and with 100% accuracy, in accordance with course reference materials and procedures, the trainee shall:

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.1	STATE the purpose(s) of the DIESEL GENERATOR/DIESEL FUEL OIL System including applicable design bases.	X	X	X	X	3
.1.2	DESCRIBE the major flowpaths for the following modes of the DIESEL GENERATOR/DIESEL FUEL OIL System operation.					
	.1 Lube Oil System	X	X	X	X	9,10,11 ,20,45-47
	.2 Fuel Oil System	X	X	X	X	5,34, 35, 36, 37
	.3 Air Start System	X	X	X	X	7, 8, 41, 42
	.4 Exhaust System	X	X	X	X	6,20, 43
	.5 Air Intake System	X	X	X	X	6, 14, 20
	.6 Cooling Water System	X	X	X	X	12, 49
.1.3	DESCRIBE the function, operation, interlocks, trips, physical location, and power supplies of the following DIESEL GENERATOR/DIESEL FUEL OIL System components.					
	.1 Lube Oil System	X	X	X	X	9
	.2 Fuel Oil System	X	X	X	X	6, 34
	.3 Air Start System	X	X	X	X	7, 8
	.4 Exhaust System	X	X	X	X	6, 42
	.5 Air Intake System	X	X	X	X	6, 14
	.6 Cooling Water System	X	X	X	X	12

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.4	STATE the physical location and function of the following DIESEL GENERATOR/DIESEL FUEL OIL system controls, indicators, and/or sensors.					
	.1 Soakback Oil System	X	X	X	X	11, 46, 57 58
	.2 Circulating Oil System	X	X	X	X	10, 44, 57
	.3 Scavenging Oil System	X	X	X	X	10, 45
	.4 Piston Cooling Oil System	X	X	X	X	10, 44
	.5 Starting Air System	X	X	X	X	7, 37, 38, 39, 57
	.6 Fuel Oil System	X	X	X	X	6, 15, 36, 57
	.7 Air Intake System	X	X	X	X	6, 14, 43
	.8 Exhaust System	X	X	X	X	7, 43
	.9 Governor Controls	X	X	X	X	15, 18
	.10 Cooling Water System	X	X	X	X	12, 48, 49, 50
	.11 Diesel Generator Controls	X	X	X	X	17, 19, 21, 25, 66
.1.5	Discuss the DIESEL GENERATOR/DIESEL FUEL OIL system automatic functions/interlocks including purpose, signals, set points, sensing points, when bypassed, how/when they are.					

Exelon Generation.

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.1 Local/Remote Panels	X	X	X	X	17, 19, 21, 24, 31
	.2 Diesel Generators	X	X	X	X	5
	.3 Air Compressor	X	X	X	X	37
	.4 Air Receiver	X	X	X	X	40
	.5 Air Dryers	X	X	X	X	39
	6. Fuel Oil Storage Tank	X	X	X	X	33
	7. Fuel Oil Day Tank	X	X	X	X	35
	8. Fuel Oil Transfer Pump	X	X	X	X	34
.1.6	Given a DIESEL GENERATOR/DIESEL FUEL OIL System Annunciator, DESCRIBE: a. The condition causing the annunciator b. Any automatic actions c. Any operational implications					
	.1 Lube Oil Temp	X	X	X	X	44, 48,
	.2 Lube Oil Pressure	X	X	X	X	29, 45, 64
	.3 Lube Oil Level	X	X	X	X	14, 47
	.4 Cylinder Exhaust Temp	X	X	X	X	43
	.5 Cooling Water Expansion Tank Level	X	X	X	X	51
	.6 Fuel Oil Storage Tank Level	X	X	X	X	33
	.7 Fuel Oil Day Tank Level	X	X	X	X	35
	.8 Fuel Oil Transfer Pump Pressure	X	X	X	X	34
	.9 Air System Pressure	X	X	X	X	38
	.10 Cooling Water Temp	X	X	X	X	29, 50
	.11 Governor Oil Level	X	X	X	X	17, 19
	.12 Air Intake Filter D/P	X	X	X	X	43
	.13 Crankcase Pressure	X	X	X	X	30, 48

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.7	Given the DIESEL GENERATOR/DIESEL FUEL OIL system, DESCRIBE the systems supporting and the nature of the support.					
	.1 Diesel Generator Auto Starts	X	X	X	X	54, 61-63
	.2 Governor Controls	X	X	X	X	15, 18
.1.8	Given the DIESEL GENERATOR/DIESEL FUEL OIL system, DESCRIBE the systems supported and the nature of the support.					
	.1 Diesel Generator Trips (setpoints not required)	X	X	X	X	27, 28, 29, 30, 54
	.2 Diesel Generator Trips (never bypassed)	X	X	X	X	28, 55
	.3 Diesel Generator load sequencing	X	X		X	68
	.4 Normal Stop	X	X	X	X	64
.1.9	DISCUSS the effect:					72
	a. A total loss or malfunction of the DIESEL GENERATOR/DIESEL FUEL OIL System has on the plant.	X	X	X	X	
	b. A total loss or malfunction of various plant systems has on the DIESEL GENERATOR/DIESEL FUEL OIL System.	X	X	X	X	67
.1.10	EXPLAIN the reasons for given DIESEL GENERATOR/DIESEL FUEL OIL System operating limits and precautions.					
	.1 Turning off the Sync Scope when operating a Diesel Generator in parallel	X	X		X	67
	.2 Operating a Diesel Generator at low load	X	X	X	X	67

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.3 Stopping a Diesel Generator with the Emergency Stop button	X	X	X	X	68
	.4 Running versus stopping a Diesel Generator after restoring from a loss of cooling water	X	X	X	X	68
	.5 Loss of the Diesel Generator Ventilation Supply Fan	X	X	X	X	68
	.6 LOCA signal	X	X	X	X	55 68
	.7 An Air Start Motor failing to disengage following engine starting.	X	X	X	X	41
	.8 Not fully opening all Cylinder Test Valves while barring diesel engines	X	X	X	X	14
	.9 Not fully closing cylinder Test Valves prior to engine starting	X	X	X	X	14
	.10 Starting a Diesel Generator with personnel in the DG HVAC Room	X	X	X	X	70
	.11 Not holding the Manual Feed Prime pushbutton for one minute	X	X	X	X	70
	.12 Circuits 13(14) and 32 not energized on their associated DC MCC for Div. 1A(1B).	X	X	X	X	71
	.13 Placing DG in Lockout	X	X	X	X	70
	.14 LOCA/LOOP with DG in Idle Position	X	X	X	X	70
.1.11	EVALUATE given key DIESEL GENERATOR/DIESEL FUEL OIL System parameters, if needed DETERMINE a course of action to correct or mitigate the following abnormal condition(s):					
	.1 High Crankcase Pressure	X	X	X	X	30
	.2 Overspeed	X	X	X	X	28, 54
	.3 Overcrank	X	X	X	X	29, 54
	.4 Low Oil Pressure	X	X	X	X	29, 54
	.5 High Water Temperature	X	X	X	X	29, 55

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.6 Reverse Power	X	X	X	X	29, 55
	.7 Loss of Excitation	X	X	X	X	29, 55
	.8 Overcurrent	X	X	X	X	30, 55
	.9 Generator Ground Fault	X	X	X	X	30, 55
	.10 Differential Current	X	X	X	X	30, 55
.1.12	Given DIESEL GENERATOR/DIESEL FUEL OIL System operability status OR key parameter indications, plant conditions, and a copy of Tech Specs, DETERMINE if Tech Spec Limiting Condition for Operations have been met, and required actions if any.					
	.1 SX	X	X		X	59
	.2 DC Electrical Distribution (DC)	X	X		X	59
	.3 AC Electrical Distribution (AP)	X	X		X	59
	.4 Diesel Generator Ventilation (VD)	X	X		X	59
.1.13	Given DIESEL GENERATOR/DIESEL FUEL OIL System key parameter indications and plant conditions, DETERMINE if the Tech Spec LCOs have been met for one hour or less LCO's.					
	.1 AC Electrical Distribution (AP)	X	X		X	59, 60
.1.14	Given DIESEL GENERATOR/DIESEL FUEL OIL System operability status and a copy of Tech Specs, DISCUSS the bases for the DIESEL GENERATOR/DIESEL FUEL OIL System Tech Spec LCO, related safety limits and Limiting Safety System Settings.	X			X	33, 35, 60, 108, 109

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
.1.15	Given DIESEL GENERATOR/DIESEL FUEL OIL System initial conditions, PREDICT how the system and/or plant parameters will respond to the manipulation of the following controls.					
	.1 Turning off the Sync Scope when operating a Diesel Generator in parallel	X	X		X	27
	.2 Operating a Diesel Generator at low load	X	X	X	X	67
	.3 Stopping a Diesel Generator with the Emergency Stop button	X	X	X	X	68
	.4 Running versus stopping a Diesel Generator after restoring from a loss of cooling water	X	X	X	X	68
	.5 Loss of the Diesel Generator Ventilation Supply Fan	X	X	X	X	68
	.6 LOCA signal	X	X	X	X	27, 28
	.7 An Air Start Motor failing to disengage following engine starting.	X	X	X	X	42
	.8 Not fully opening all Cylinder Test Valves while barring diesel engines	X	X	X	X	14
	.9 Not fully closing cylinder Test Valves prior to engine starting	X	X	X	X	14
	.10 Starting a Diesel Generator with personnel in the DG HVAC Room	X	X	X	X	70
	.11 Not holding the Manual Feed Prime pushbutton for one minute	X	X	X	X	70
	.12 Circuits 13(14) and 32 not energized on their associated DC MCC for Div. 1A(1B).	X	X	X	X	71
.1.16	EVALUATE the following DIESEL GENERATOR/DIESEL FUEL OIL indications/responses and DETERMINE if the indication/ response is expected and normal.					
	.a Div. 1 & 2 Cranking Sequence					
	.1 Engine Cooling Water Pressure >20 psig.	X	X	X	X	62
	.2 Engine Speed >125 rpm.	X	X	X	X	62
	.3 Generator Voltage at ~ 80% Rated	X	X	X	X	63
	.b Div. 3 Cranking Sequence					

Objective #	Objective Description	SRO	RO	NLO	STA	Pg. #
	.4 Engine Speed >150 rpm.	X	X	X	X	64
	.5 Engine Speed >870 rpm	X	X	X	X	64

Evaluation Method & Passing Criteria: WRITTEN EXAMINATION WITH SCORE > 80%

References

- K2801-0076, 2200 kW Generator Set
- K2861-0002A, Tandem Diesel Generator (Division I & II)
- CPS 3506.01, Diesel Generator and Support Systems
- 8207.06 Emergency Diesel Engine Scheduled Maintenance
- CPS 9080.01 Diesel Generator 1A(B) Operability-Manual and Quick Start Operability
- CPS 9080.02 Diesel Generator 1C Operability – Manual and Quick Start Operability
- CPS 9080.13 Diesel Generator 1A(B) 24 Hour Run and Hot Restart – Operability
- CPS 9080.14 Diesel Generator 1C 24 Hour Run and Hot Restart – Operability
- M05-9035, Diesel Generator Set Lube Oil
- P&ID M05-9036, Diesel Generator Set Fuel Oil P&ID
- E02-1DG99, Diesel Generator System (DG) Schematic Diagrams
- CPS Technical Specifications
- SOER 83-1, Diesel Generator Failures
- OE 7264, Bearing Failure and Motorizing of the Division III Diesel Generator
- CPS LER 96-011, Priming Of Emergency Diesel Generators During Performance Of Certain Surveillance Tests Determined To Be Preconditioning
- EC 330661 L O Dipstick level markings
- EC 349235 Div I DG Governor model upgrade.
- INPO 12-012, Traits of a Healthy Nuclear Safety Culture.
- SER 3-05 Weaknesses in Operator Fundamentals
- SOER 10-02, Engaged, Thinking Organizations
- IER 11-3, Weaknesses in Operator Fundamentals
- INPO 15-004 Operations Fundamentals
- OP-AA-101-113, Operations Fundamentals
- ECs 383490, 383491 – Removal of Div 1&2 Overvoltage Protection.
- INPO 10-004, Principles For A Strong Operational Focus

Commitments: None

LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
0	Unknown	Format
1	Unknown	Format
2	Unknown	Format
3	Unknown	Format
4	11/24/01	*Update to new Exelon format per TQ-AA-210-3201 R00 Lesson Plan Template (Portrait). Incorporated comments from System Engineer. Incorporated LP 86264 & 87264 into revision. LPs will be deleted when approved*
5	03/30/02	Update to new Exelon format per TQ-AA-210-3201 R00 Lesson Plan Template (Portrait). Incorporated comments from System Engineer. Revised and updated objectives. Resolved missing KA links to lesson plan. Added various tracer items to include procedure reference changes, Speed Droop OPEX.
6	05/30/03	Updated to include info from EC330661, Tracer #2003-05-0129, Tracer #2002-11-0022A, Tracer #2003-02-0100A
7	08/21/03	Incorporated TRACER 2003-07-0121A.
8	09/22/04	Incorporated TRACER # 2004-04-0105A.
9	06/13/06	Incorporated TRACER # 2005-03-0087A and Removed the reference to Engineering system descriptions.
10	01/10/07	Updated to include discussion and pictures of the new style governor installed on Div 1 DGs per EC 349235. Include discussion on why upper gallery sight glass is checked during DG pre-starts. Tracers 2006-08-0052A and 2006-09-129A. Added figures 25, 26 and 27. Pages x, 17, 48, 78, 102, 103 and 104.
11	03/20/07	Revised the Air Start system drawing per tracers 2007-02-0034A and 2007-02-0074A. Page 96 figure 18 and Big Notes.
00	05/23/08	Updated lesson plan number and objectives to align with associated KA. Incorporated TRACER 2007-08-035A, 2007-07-0156A, 0157A, 0158A, all of which address EDG Fuel Oil Day Tank level setpoints and admin limits per EC 366152 & EC Eval. 366167. Incorporated TRACER 2008-05-0114A, which adds words to indicate that any color other than blue for moisture indicator dessicant warrants an IR to address.

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LESSON PLAN HISTORY PAGE		
REV.	**DATE**	**DESCRIPTION**
01	07/02/10	Incorporated TRACER's from recent procedure changes & ILT student feedback: Tracer No's. 2010-01-0086A, 2009-10-0045A, 2008-05-0126A, 2010-06-0039A, 2008-07-0016A. These incorporated FOST Admin level changes. Revised DG Cooling System drawing. Updated Big Notes.
02	06/05/12	Added SOER 10-02, IER 11-3, Ops Fundamentals OP-AA-101-113, and PSNSC to list of references and referred to them in selected portions of the lesson plan. Incorporated Action item (ACIT 01067836-05), Also incorporated ITS 3.8.3, changes, EC 330661, and minor DG/DO procedure changes as needed.
03	01/30/13	Incorporated Action items TREQ 1176976-61, 65, and 1341299-65 changes. EC 383490 (01341299-65), and EC 383491 (1381590-02).
04	10/14/15	(MINOR REVISION) Incorporated Action item TREQ 01621344-32. Preventing reverse power trips when unloading the Div. 3 DG. DG Big Note was not impacted.
005	12/08/16	(MINOR REVISION) Added reference to INPO 10-004, Principles For A Strong Operational Focus. DG Big Note was not impacted.
006	05/16/17	(MINOR REVISON) Added synchronizing light indication per AR 01687009 assignment #76. Big Note was not impacted.

Instructional Methods:

- lecture/discussion
- activities
- small group activities

Media:

- PowerPoint
- white board
- flip charts
- handouts
- trainee text

112~~109~~

I. Introduction

A. Topic Introduction

The Diesel Generator System provides an independent, onsite source of emergency power to the Division I, II, & III Class 1E busses. In the unlikely event a Design Basis Accident (DBA) occurs coincident with a Loss of Off-site Power (LOOP), the Diesel Generator System will automatically start and supply power to essential equipment that has the capability of mitigating the consequences of the accident. Additionally, the DG System will provide power to the Divisional Busses when normal power is lost.

Each Diesel Generator is equipped with the following independent auxiliary systems:

- Fuel Oil Storage and Transfer
- Combustion Air and Exhaust
- Starting Air
- Lube Oil
- Cooling Water

B. Training Session Overview

1. The student will learn this topic through approximately 6.0 hours of classroom instruction, comprised mainly of:
   - Lecture/Discussion
   - Activities

C. Objectives

1. The objectives provide the foundation for learning this topic; The complete list of objectives can be found at the front of the student handout, which include the following:
   a. Recalling the system purpose and major system flowpaths, and major component functions.
   b. Recalling the function, theory of operation, controls, automatic functions and/or interlocks associated with major system components.

Traits of a Healthy Nuclear Safety Culture provide behaviors and actions that support a culture of safety in all aspects of plant operation. The cornerstones of these principles are:

- **Everyone is personally responsible for nuclear safety.**
- **Leaders demonstrate. commitment to safety**
- **Trust permeates the organization.**
- **Decision-making reflects safety first.**
- **Nuclear technology is recognized as special and unique.**
- **A questioning attitude is cultivated.**
- **Organization learning is embraced.**
- **Nuclear safety undergoes constant examination.**

c. Recalling functional interrelationships between this system and other plant systems.

d. Demonstrating an understanding of system precautions and limitations.

e. Predicting the impact/consequences of system problems.

2. Review the objectives to familiarize yourself with the knowledge necessary to attain mastery of this topic.

D. Evaluation

1. A check for understanding of objectives will be evaluated by one or more of the following:

a. The instructor periodically throughout the presentation in the form of an interim summary.

- A written examination with a minimum score of 80%.Functional interrelationships between this system and other plant systems.
- Tracing system flowpaths.
- Describing operations, controls, automatic functions and/or interlocks.
- Predicting the impact/consequences of various plant events.

E. Management Expectations

1. Safe nuclear power plant operation is based upon the principle that each individual accepts the unique and grave responsibility inherent in using nuclear technology.

2. When operations personnel are faced with unexpected or anomalous system behavior, they are expected to take conservative action to place the system/plant in a safe condition.

3. A thorough understanding of the Diesel Generator and Support System and its interrelationship with other plant systems is required for an operator to recognize unexpected or anomalous system behavior and understand its impact on personnel safety and safe operation of the plant.

SER 03-05, IER 11-3, INPO 15-004, and SOER 10-02 discuss weaknesses in operator fundamentals which have led to many significant industry events. The Operations Fundamentals (as outlined in OP-AA-101-113) provide specific guidance on how to address the weaknesses identified in SER 03-05, IER 11-3 and SOER 10-02 to help ensure a safe nuclear culture. SOER 09-01 provides information and recommendations for shutdown and refuel activities and training.

In addition, discuss INPO 10-004 as it relates to the Diesel Generator, specifically the second principle:
2. The plant operational risk associated with equipment removed from service or degraded and from planned risk activities is maintained low. Inadvertent operational events are prevented through planning, preparation, controls, contingencies, and communication.

II. System Purpose

A. Purpose

The Diesel Generator System provides an independent, onsite source of emergency 4160 VAC, 60Hz power to the Division I, II and III Class 1E busses. In the unlikely event that a design basis accident (DBA) occurs coincident with a loss of off-site power (LOOP), the Diesel Generator (DG) System will automatically start and supply power to essential equipment that has the capability of mitigating the consequences of the accident. The diesels also provide power to Division I, II and III buses anytime normal power is not available.

[.1.1.]

B. Design Bases

1. The Div. I, II and III DG's are redundant in that only 2 of the 3 are required to meet the power requirements of the essential/safe shutdown equipment.

2. The Diesel Generator System component safety class and seismic category are delineated in USAR table 3.2-1.

3. Minimum onsite capacity of the Diesel Generator Fuel Oil Storage and Transfer System shall be sufficient to operate each diesel generator for 7 days while supplying maximum post-Loss of Coolant Accident (LOCA) load demand.

4. The Air Starting Systems for each DG set can start its engine(s) five times in succession without recharging the air receivers. The Air Start system will start the engine so that the DG is operating at rated speed, voltage and frequency within 12 seconds following receipt of the start signal.

C. Surveillance Testing Requirements.

To ensure DIV I, II and III Diesel Generators and supporting systems are maintained in a condition to meet the required function of each division, frequent checks are made on oil levels/temperatures, starting air pressure, coolant level, and standby oil pumps running. Additionally, scheduled surveillance testing is preformed.

1. Manual Start Operability: This surveillance starts Div 1 and 2 DG at idle speed. Once the DG is warmed up the speed is increased to operating speed and the DG is loaded.

Operating logs are taken while the DG is running and parameters are checked for out of spec conditions.

2. Quick Start Operability: This surveillance starts the DG at rated speed and time from start signal to rated speed is checked to ensure the 12 second Tech Spec is achieved as well as proper voltage and frequency. The DG is then loaded and logs are taken to monitor operating conditions.

3. Fuel Oil Transfer Pump Operability: The Fuel Oil Transfer Pump supplying fuel oil from the storage tank to the service day tank is tested for capacity and vibrations during operation. The service day tank is drained back to the storage tank. The transfer pump will auto start on service day tank low level and a timed run records the amount of fuel discharged to the service day tank.

4. Diesel Generator ECCS Integrated Testing: This is a series of surveillance tests that demonstrate the ability of the Diesel Generator to automatically start and automatically supply the required loads during a Design Base Accident.

III. SYSTEM FLOWPATH(S)

A. System Overview

Three independent, physically separated diesel generator sets located at 737 DG Building provide an emergency source of power to the Division I, II and III Class 1E, 4.16 kV busses. The Division I and II DG's are tandem mounted 12 and 16 cylinder engines with center mounted generators. Division III DG has a single 16 cylinder engine. [.1.5.2]

Each diesel engine drives an AC generator, which is mechanically linked, to the engine crankshaft. The DG's produce electrical energy that is then fed to the Class 1E, 4.16 kV busses where it is distributed to loads required for safe shutdown of the plant following a DBA LOCA and/or LOOP.

Each DG is equipped with the following independent auxiliary systems:

1. Fuel Oil Storage and Transfer
2. Combustion Air and Exhaust
3. Starting Air
4. Lube Oil
5. Cooling Water

B. Fuel Oil System Storage and Transfer

A dedicated fuel oil storage tank provides the required onsite inventory of fuel oil for each DG. A fuel oil transfer pump transfers fuel oil from the Fuel Oil Storage Tank to the associated Fuel Oil Day Tank. **Figure 17 [.1.2.2]**

Student Exercise: Review/Trace System flow path for Fuel Oil System Storage and Transfer.

When the diesel engine is started a DC powered Fuel Priming Pump starts to initially provide fuel oil to the engine. Once started an engine driven fuel oil pump provides the fuel oil for engine operation. (Divisions 1 & 2 only) When the diesel engine reaches 850 rpm the DC fuel oil pump stops. On Division 3 the DC powered fuel priming pump runs continuously when the diesel engine is started. Excess fuel from the DC fuel pump is bypassed through a 75 psig relief valve that opens when the engine driven pump develops sufficient pressure to supply fuel to the engine.

Figures 10&17) [.1.3.2] [.1.4.6]

Both the engine driven fuel oil and DC fuel oil priming pumps draw fuel from the fuel oil day tank through a suction strainer and deliver it to the engine through an engine mounted fuel oil filter. The fuel passes through the filter elements to the fuel manifold supply line where it is directed to the fuel injectors via the injector inlet filters. A portion of the fuel supplied to the injectors is sprayed into the cylinder combustion chambers where it ignites, driving the piston through its power stroke.

Unused fuel flows through the injector to lubricate and cool the working parts. Excess fuel flows through the return line fuel oil filter to the return line manifold after passing through the injectors. The return line manifold directs the excess fuel oil back to the day tank. A 10-psig in-line relief valve maintains a back pressure on the fuel injectors by restricting flow returning to the day tank.

C. Combustion Air Intake and Exhaust System

Student Exercise:
Review/Trace Cylinder Air Intake and Exhaust flow path

[.1.3.4] [.1.3.5] [.1.4.7]

Combustion air is drawn through a screen grating and passes through dry filter/silencers that remove particulate. Filtered combustion air enters the turbocharger where its pressure is increased. The increase in air pressure is accompanied by an increase in air temperature. The air discharged from the turbocharger passes through an after cooler to reduce its temperature and increase its density. This increases the amount of oxygen admitted to the combustion cylinders. The pressurized air then enters the air box where it is directed to the

[.1.2.4, .1.2.5] (Figure 6)

individual combustion chambers. The incoming combustion air forces exhaust gases from the previous power stroke out through the exhaust valves. The piston compresses combustion air as it travels to the top dead center position at which point fuel is injected into the cylinder. Fuel injected to the combustion cylinder ignites spontaneously as it mixes with the hot, compressed combustion air and forces the piston down through the next power stroke.

As the piston travels downward, pressurized air from the air box enters the cylinder forcing the combustion gases out of the cylinder through the exhaust valves. Exhausted gases flow through the exhaust manifold and are routed to the rear of the turbocharger and drive the turbocharger turbine. The turbocharger turbine drives the centrifugal blower that pressurizes engine combustion air. After the exhaust gases have passed through the turbocharger's turbine, they are directed through the exhaust piping and silencer/muffler, and are then discharged through the Diesel Building roof to the atmosphere. **[.1.4.8]**

D. Air Starting System

1. Division I & II

Student Exercise:
Review/Trace flow path for DG Air Start System.

[.1.3.3]

The Air Start Systems for the Div. I and Div. II Diesel Generator sets consist of three air start motors per engine, two air compressors, two receiver tanks, an air dryer, four in-line oilers and various valves. The Div. I and II air start systems are identical. The following flow path description is applicable to the Div. I and Div. II Diesel Generators. **(Figure 18)**

Each of the motor driven air compressors produce pressurized air that is passed through a dryer and is then used to charge the two starting air receivers. The starting air receivers ensure an adequate supply of air is available to start the DG's. Crosstie piping provides a means of charging both air receivers from either air compressor. The air receivers are normally charged by a combination of airflow from both **[.1.2.3] [.1.4.5]** compressors as it exits the common air dryer and associated filters.

When a Diesel Generator (DG) start signal is received, the air start solenoids on both air start trains energize and open the associated main air supply valves. Starting air passes through the solenoid valves to the diaphragms of the air-operated main air supply valves, causing them to stroke open. This provides a flow path of air from the air receivers to the air start motors. Starting air flows through the air start motors rotating the pinion gears. The pinion gears, in turn, engage with and drive the engine flywheel ring gear, causing the engine to crank. Only one train of air start motors, two on one engine and a single motor on the other engine, are required to engage in order to turn the engines over.

[.1.2.3]

The air start solenoids also provide piloted air to the booster servomotors on each engine to drive the electro-hydraulic actuators on each engine to the maximum fuel position during starting.

2. Division III

The Div. III Diesel air start system operates two pairs of air start motors to start a single engine. When a start signal is received by the Div. III DG, the air start solenoids on both trains energize and cause the associated valves to open. The starting air passes through these valves and enters the lower air start motors. The starting air causes the pinion gear of each motor to jog forward until it engages with the engine flywheel ring gear. Engagement of the lower pinion gear uncovers a port which provides an air flowpath to the upper air motor pinion gear piston, causing it to jog forward and engage the ring gear. When the upper air start motor pinion gear engages it uncovers a port that allows air to open the main air supply valve. This provides a flowpath from the air receiver to the pair of air start motors. Only one pair of air start motors is required to start the Div. III DG.

(Figure 19)

[.1.2.3] [.1.3.3]

The air start solenoids also provide piloted air to the booster servomotors to drive the mechanical-hydraulic actuator to the maximum fuel position during starting.

Student Exercise:

Review/Trace flow path for DG Lube Oil System.

E. Lube Oil System

Each diesel engine has a lube oil system comprised of the following subsystems:

[.1.3.1]
(Figure 20)

- Main Lubricating System
- Piston Cooling System
- Scavenging Oil System
- Circulating Oil System
- Turbo Soakback Oil System

1. Main Lubricating System

The main lubricating system supplies oil to most of the engine's moving parts while the DG is in operation. Both the main lube oil pump and piston cooling pump are driven by the crankshaft through the accessory gear assembly, and share a common casing and suction source. The main lube oil pump takes a suction through a strainer on the strainer sump housing and discharges to the main lube oil manifold. A relief valve mounted in parallel with the main lube oil manifold limits the maximum oil pressure. If the relief valve lifts, part of the discharge from the main lube oil pump will be directed back to the oil pan sump.

[.1.2.1]
(Figures 7,8 & 20)

The main lube oil manifold is located inside the airbox, above the crankshaft and extends the length of the engine. It provides lube oil to the following engine components:

a. Main Crankshaft Bearings

b. Connecting Rod Bearings

c. Torsional Damper

d. Crankshaft Accessory Drive Gear

e. Crankshaft Thrust Bearings

f. Camshaft Drive Gear Stub Shaft Brackets

g. Upper and Lower Stub Shaft Bearings

h. Camshaft Bearings

i. Rocker Arm Components

j. Turbocharger Bearings

k. Idler Gear

l. Planet Gear Assembly

m. Auxiliary Drive Bore

Leak-off oil from the lubricated components drains back to the engine oil pan sump.

2. Piston Cooling System

The piston cooling pump delivers oil to the two piston cooling oil manifolds. Each piston/cylinder receives cooling oil from the associated manifold. This oil cools and lubricates the piston and connecting rod assemblies. Excess piston cooling oil returns to the engine oil pan sump.

[.1.2.1] [.1.4.4]

3. Scavenging Oil System

The scavenging oil pump is driven by the engine crank shaft through an accessory gear assembly and takes a suction on the engine oil pan sump through a strainer. Pump discharge pressure forces the oil through the lube oil filter and the lube oil cooler. The oil exiting the cooler is then routed to the strainer box sump. The strainer box sump is the suction source for the main lube oil and piston cooling oil pumps. A dam regulates oil level in the strainer sump. Excess oil in the strainer sump will spill over the dam and return to the oil pan sump.

[.1.2.1] [.1.4.3]

4. Circulating Oil System

The AC motor driven circulating oil pump circulates warm oil through the diesel engine when it is shutdown to ensure it is ready to start.

[.1.2.1] [.1.4.2]

The circulating oil pump takes a suction on the oil pan sump and discharges oil through the lube oil filter and cooler. An immersion heater heats the engine cooling water which circulates through the lube oil cooler. As the oil is circulated through the lube oil cooler it is warmed by the heated jacket water flowing through the lube oil cooler. Warm oil leaving the lube oil cooler flows into the strainer box and overflows into the engine oil pan sump. The circulating pump also provides prelube oil directly to the main bearing header through a tap-off from the lube oil cooler. The lube oil lubricating main bearing components drains back to the engine oil pan sump.

A DC powered circulating oil pump is installed in parallel with the AC circulating oil pump as a backup. If the AC circulating oil pump motor fails, trips or is turned off, the 125V DC motor driven pump will automatically start and maintain the same flow paths as the AC pump.

The circulating oil pump runs continuously with DG in standby or in service. Once the attached main lube oil pump reaches required pressure the circulating oil pump relieves back to the sump.

5. Turbo Soakback Oil System

The turbo soakback oil system is similar to the circulating oil system. The AC motor driven Turbo Soakback oil pump circulates warm oil through each diesel engine turbocharger while the engine is shutdown. This keeps the turbocharger warm, prelubricated and ready to start. The turbo soakback oil system also allows unrestricted restarting following engine shutdown.

[.1.2.1.] [.1.4.1]

The Turbo Soakback oil pump takes a suction on the engine oil pan sump and supplies oil through the Turbo Soakback oil filter to the turbocharger bearings and the rear gear drive train. Oil leak-off from the lubricated components drains to the engine oil pan sump. A 75 psi check valve will open and allow oil to flow to the strainer sump through the lube oil filter and cooler if oil pressure to the turbocharger is excessively high or the soakback filter clogs up.

The turbo soakback oil system runs continuously when the engine is in operation. This provides a means of removing residual heat from the turbo charger bearings and the rear accessory gear drive train. Once the attached main lube oil pump reaches required pressure the turbo soakback oil pump relieves back to the sump.

A DC powered turbo soakback oil pump is installed in parallel with the AC soakback pump as a backup. If the AC soakback pump motor fails, breaker trips, or is turned off the DC turbo soakback pump automatically starts and supplies the same flow path as the AC soakback pump.

F. Engine Cooling Water/Jacket Water System

[.1.3.6]

Student Exercise:
Review/Trace the flow path of the Engine Cooling Water/Jacket Water System (Figure 21).

The engine cooling water system for each diesel engine consists of two engine driven cooling water pumps, a jacket water heat exchanger, temperature regulating valve, expansion tank and immersion heater. **(Figures 9 & 21)**

During engine operation engine cooling water pumps discharge to two separate jacket water headers. Cooling water flows through the engine cylinder jackets. Engine cooling water flows into the engine discharge manifold and through the temperature regulating valve. The thermostatically controlled temperature regulating valve routes the cooling water through the jacket water heat exchanger and the lube oil cooler. If the temperature of the jacket water is low, the regulating valve will direct the flow through the lube oil cooler alone. This will bypass the heat exchanger and direct flow to the suction of the two engine cooling water pumps. An expansion tank accommodates thermal expansion of the cooling water and is connected to the suction side of the two cooling water pumps.

[.1.2.6]
[.1.4.10]

An immersion heater provides a means of heating the jacket water during periods of shutdown in order to maintain the diesel engines in a constant state of readiness. A natural convection flow path is established through the engine and the lube oil cooler due to the thermo-syphon effect induced by the immersion heater. This natural convection flowpath warms the lube oil and the engine block by heating oil passing through the lube oil cooler.

Interim Summary:

Review System Overview Section:

- **Purpose**
- **Design Bases**
- **Major Flow Paths**

Request clarification on questions that may arise during review.

IV. Components

A. Diesel Engine Mechanical Components

1. Crankcase/Air Box

The crankcase is the main structural part of the engine. The area enclosed by the crankcase is commonly referred to as the air box. The main lube oil, piston cooling oil, and jacket water cooling headers pass horizontally through the air box with connections to each power assembly. Crankcase and air box pressure is available on local gauge panel for each DG.

(Figures 6)
[.1.2.5] [.1.3.5] [.1.4.7]

2. Cylinder Test Valve (Kenie)

There is a cylinder test valve on each of the divisional diesel engine combustion cylinders. The cylinder test valves are manually opened to relieve compression during engine barring or to connect test equipment for engine analysis. During routine operation of the DG, the engine is barred to inspect cylinders for trapped jacket water or oil before manually starting the engine. If only one or two cylinder test valves are left closed then the engine will be visibly more difficult to bar over. If three or more cylinder test valves are not fully opened during prestart checks the diesel engines cannot be barred over. If cylinder test valves are left open during engine operation flames will shoot out of the cylinder test valve outlet ports. CAUTION: The test valves become very hot during engine operation. Valves should not be adjusted without using the wrench and wearing proper safety equipment.

[.1.10.8]
[.1.10.9]
[.1.15.8]
[.1.15.9]

3. Oil Pan Sump

The oil pans are steel base assemblies that support the diesel engine crankcase and airbox. Each engine oil pan sump contains sufficient inventory to support 7 days of DG operation under maximum post LOCA electrical load. A dipstick in the DG sump is used to determine the amount of oil in each sump. The dip stick is scribed with the following marks: High, Full, 7 Days, 6 Days, and Low.

[.1.6.3]

For the 16 cylinder engines, 7 Days is equal to 347 gallons and 6 Days is equal to 327 gallons.

For the 12 cylinder engines, 7 Days is equal to 284 gallons and 6 Days is equal to 269 gallons.

The sump has locked shut drain valves which allow for oil removal if needed. The oil drains to sumps located in the fuel oil storage tank rooms which pumps to the #2 Oil Separator.

4. Engine Accessory Drive Gear Train

   The accessory drive gear train provides gear drive connections from the crankshaft to drive the seven engine driven pumps. Two jacket/cooling water pumps, one governor oil pump, a main and piston cooling oil pump (driven on a common shaft), and a scavenging oil pump and engine driven fuel oil pump (driven on a common shaft).

   (Figures 1 and 3)

5. Engine Camshaft Drive Gear Train

   The power necessary to drive the engine camshafts and turbocharger before it is driven by the engine exhaust comes from the engine crankshaft.

   (Figure 4)

6. Fuel Injector and Linkage

   [.1.4.6]

   The fuel injector linkage connects the fuel injectors to the governor output shaft. When governor output shaft rotates in response to a change in engine load demand the injector control rods (two) pushes out or pulls in. This rotates the injector control shaft (two) or fuel racks which rotates the injector plunger to adjust effective size of the injector fuel cavity.

7. Governor

   a. Division I & II

      Div. I and II DG speed is controlled by Woodward EGB-13P governors. EGB-13P governing system incorporates both electric and centrifugal governors, either which has the ability for complete control of the engine. During normal operation, the electrical portion controls fuel to the engine. In the event of control signal to the electrical portion of the governor is interrupted, the fuel rack positions to full fuel, and the centrifugal portion will take over and control engine speed at the setting of the centrifugal portion. The centrifugal portion setting is 5% higher than the electrical portion setting.

      [.1.4.9] [.1.7.2]

      The electrical portion of the governor receives a signal from a control box. The control box is given the requested speed-setting signal from the Voltage

Regulator & Governor Control Switch. A Speed Sensor located on the rotating shaft between the engine and generator feeds back to the control box that compares the two signals. If an error is sensed between the two signals, a correction is generated by the control box and sent to the electrical portion of the governor.

Under normal operating conditions the pilot valve plunger controls flow of oil to the power piston that controls the position of the fuel rack through various linkages. The plunger is connected to an armature magnet which is suspended in the field of a two coil polarized solenoid. The output signal from the control box is applied to the coil that moves the coil and pilot valve plunger up or down. The plunger moves down if the signal is the result of a decrease in engine speed or an increase in speed setting in the control box. The plunger moves up if the signal is the result of an increase in engine speed or a decrease in speed setting. Centering springs return the armature magnet and pilot valve plunger to center positions when the control signal returns to its on-speed voltage value.

Fig 22

The EGB-13P is particularly suited for use with the tandem engine Div. I and II DG's. A single electric control unit is used with two proportional actuators connected in series with the control unit output. This allows each actuator to receive the same control signal and balance tandem engine load.

The speed setting on the mechanical governor is approximately 5% higher than the electrical actuator. If engine speed exceeds the electrical governor setting, the mechanical governor will automatically limit engine speed. Engine speed is normally controlled from the Main Control Room controls, but can be locally controlled by manually adjusting the speed setting of the mechanical governor. If the electric control unit fails low it will cause the electro-hydraulic actuator to operate on the mechanical governor and increase the fuel rack setting. Consequently the engine will operate at an elevated speed or will pickup additional load if the DG is paralleled to the grid. A control signal failure high will cause the governor to fail in the minimum fuel position, which will shutdown the DG.

The mechanical section of the Div. I and II DG governors is very similar to the Div. III DG governor. The Div. III governor is strictly a mechanical-hydraulic governor.

Major Instrumentation

Each governor has a governor oil sightglass on the governor. **[.1.6.11]**

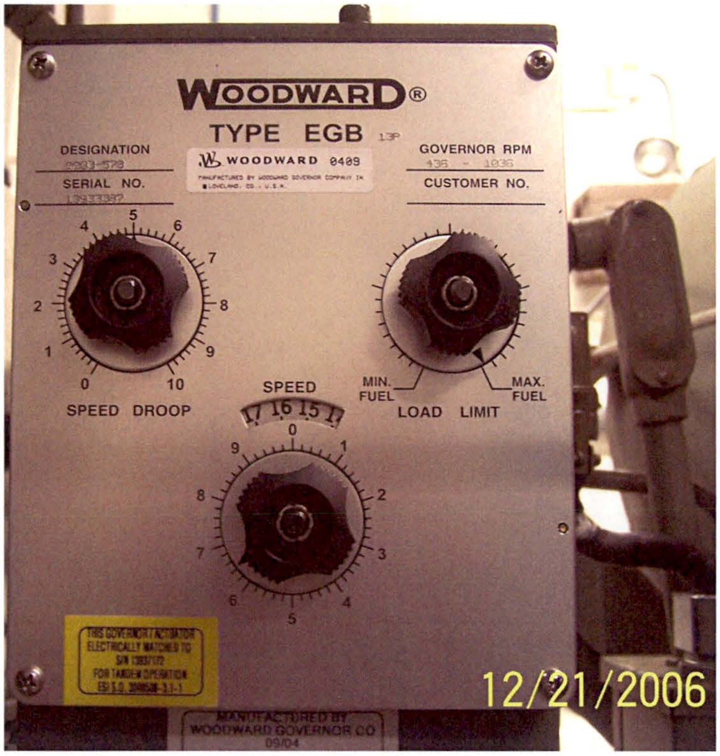
Control and Interlocks **[.1.4.11] [.1.5.1]**

DG 1A(1B) VOLT REG & GOV SELECTOR SWITCH: Allows the control room operator to select Div. I & II DG voltage regulator and governor (engine speed) control from either the Main Control Room or the DG local control panel. **Optional:**

Both Div. I and II DG local engine control panels have governor RAISE-LOWER control switches for locally adjusting engine speed. Since Div. I and II DG's have tandem mounted 12 and 16 cylinder engines one governor control switch controls both engines simultaneously.

Division I governor was replaced with the newer model Woodward EGB-13P due to the older model was no longer supported by the manufacturer. Division II governor was overhauled recently and will not be replaced with the newer model until 2016. Operation of the newer model is identical to the older model. The following picture is the new model governor and requires no operation by the field operator during operation.

Synchronizing Lamps will indicate dark ie no lights at the 12 o'clock position when synchronizing the DG's with a RAT or ERAT. At the 6 o'clock positon the lights are the brightest. These indications are on the MCR panel P601. These lights are the same for a three DG's.



b. Division III

The Div. III DG has a Woodward UG8 governor. The UG8 is a mechanical-hydraulic governor. An internal hydraulic gear pump produces the hydraulic pressure used for controlling the governor's output shaft position. The gear pump is driven by the governor driveshaft which in turn is driven by the engine accessory drive gear train.

The UG8 power piston controls the governor output shaft through a mechanical linkage. Governor output shaft position is controlled by regulating the flow of oil to the top or bottom of the power piston. The governor output shaft is coupled to the fuel racks which control the amount of fuel sprayed into the combustion cylinder by the injector. Rotating the fuel racks adjusts the amount of fuel admitted to the combustion cylinders by the fuel injectors. Engine speed/load is ultimately controlled by rotating the fuel racks. Load changes on the Div. III DG should be performed slowly and stepwise to allow the DG load to stabilize to prevent DG reverse power trips.

[.1.4.9] [.1.7.2]
Figure 23

<u>Stress</u>:
There have been past Div. 3 DG reverse power trips. The Div. 3 DG's mechanical governor responds differently than Div. 1 and 2 to changes in load. Thus, Load changes on the Div. III DG should be performed slowly and stepwise to allow DG load to stabilize to prevent DG reverse power trips.

Major Instrumentation

[.1.5.1] [.1.6.11] [.1.4.11]

The governor has a local governor oil sight glass.

Diesel engine speed for Div. III engine is displayed on the local engine panel.

Control and Interlocks

DG 1C VOLT REG & GOV SELECTOR SWITCH: Allows the control room operator to select Div. III DG voltage regulator and governor (engine speed) control from either the Main Control Room or the DG local control panel.

Div. III local control panel has a governor RAISE-LOWER control switch for locally adjusting engine speed.

There are three control knobs on the Div. III engine governor: LOAD LIMIT, SPEED DROOP, and SYNCHRONIZER.

LOAD LIMIT: Limits the load that can be placed on the engine by restricting the travel of the governor output shaft. This limits the amount of fuel that can be supplied.

SPEED DROOP: Controls DG droop for paralleling with offsite power sources. Speed Droop provides positive control to lower engine speed as load is increased. It is incorporated in the governor through a linkage which varies spring compression of rotating flyweights which control fuel to the engine as it speeds up or down. Increased fuel reduces spring compression and reduces the governor speed setting accordingly, and the governor will gradually reduce speed as load is increased. Normally set at 0 for no speed droop. Setting this control for 50 provides adequate speed droop (approximately 3% droop) to operate in parallel with offsite power. As Speed Droop is reduced toward zero the unit becomes able to change load without changing speed. When the DG 3 governor is operated in the droop mode, the DG is declared inoperable.

(Figure 23)

SYNCHRONIZER: This is a manual adjust for engine speed control. It is mechanically linked to the governor speed changer motor used to adjust Engine speed from the local panel or the Main Control Room.

Under a metal cover on the Div. III governor face are limit switches which limit the maximum and minimum speed adjustment of the governor speed changer motor from the local or main control room engine controls.

8. Turbocharger

The turbocharger centrifugal blower has two different driving sources; a gear drive attached to the engine accessory drive gear train and a turbine driven by the engine exhaust. The accessory gear drive train drives the turbocharger fan with an overrunning clutch during engine startup and low load operation. When the engine approaches full load and the heat energy of the engine exhaust exceeds 1000 °F the turbine drives the turbocharger.

(Figure 1,5)
[.1.2.5] [.1.2.4]

The turbocharger is kept warm and prelubricated by the turbocharger soakback oil system. The main lube oil system provides turbocharger lubrication through the turbocharger soakback oil filter during engine operation. The soakback oil system controls cooldown of the turbocharger and allows immediate restarting of the engine following extended operation.

[.1.2.1]

The jacket water cooling system cools the turbocharger aftercooler. The jacket water cooling system heater maintains turbocharger and soakback oil temperature while in standby.

B. Generator

1. Division I and II

The Div. I and Div. II DG's are 4160 VAC, 60 Hz, 8 pole, dual bearing, brushless, rotating field type generators. Div. I generator differs from Div. II in that it is specially designed to handle extremely heavy motor starting loads with only 25% maximum voltage drop. The Div. I generator is rated at 3869 kW (676.6 amps @ 96.5% eff.) and supplies power to the Class 1E bus 1A1. Div. II generator is rated at 3875 kW, and is designed for fewer motor starts and more lighting loads. Div. II supplies power to the Class 1E bus 1B1.

The exciter is inside the generator housing and is mounted on the same shaft with the rotating field windings. The exciter field is controlled by a voltage regulator which can be varied as necessary to maintain the required generator output voltage.

The brushless generator utilizes an AC exciter whose armature is mounted on the main shaft, and whose AC output is rectified by a rotating rectifier bridge and fed directly into the generator field. This greatly simplifies and reduces generator maintenance as it eliminates commutators, collectors, brushes and brush riggings.

The generators are automatically flashed as they are brought up to speed by applying DC voltage to the exciter field. This provides the initial field excitation that is required during start-up for the generator to begin producing voltage. As generator voltage builds, the generator provides the necessary AC voltage to the exciter and the voltage regulator controls generator voltage output. At this point the generator may be loaded and the voltage regulator automatically maintains voltage regardless of load changes.

Major Instrumentation

The following instrumentation is located on the local engine control panel: **[.1.5.1]**

a. Diesel Generator Voltage-AC Volts

b. Diesel Generator Frequency-Hertz

c. Engine running time-Hours

d. Generator Load Current-AC Amps

e. Generator Load Power-AC Kilowatts

f. Generator Load Reactive-AC KVARS

Control and Interlocks

LOCAL ENGINE CONTROL PANEL CONTROLS: **[.1.4.11]**

a. Maintenance Switch: Two position OPERATE-LOCKOUT. In OPERATE the DG responds to all manual and automatic start and loading commands. In LOCKOUT the DG will not start or load. The **[.1.14]**

Maintenance Switch for the Div. III DG is a three-position switch – MAINT, AUTO, and TEST. The AUTO-MAINT positions control engine operation the same as the OPERATE-LOCKOUT positions described above. The TEST position allows local starting of the DG. Placing the DG Maintenance [Engine Control] Switch in LOCKOUT [MAINTENANCE] makes the DG INOPERABLE and UNAVAILABLE; if in Mode 1, 2, or 3.

b. RUN-IDLE CONTROL SWITCH: Two positions: RUN-IDLE. This feature is only present on Div. I & II DG's. DG responds normally to starting/loading commands in RUN. IDLE allows the operator to start/stop the DG and perform a controlled warmup/cooldown of the diesel engines at 400 RPM. On a LOCA or Loss-of Offsite Power (LOOP), the RUN-IDLE Switch is bypassed and the DG will accelerate to rated speed and voltage.

c. Governor: RAISE-LOWER. Controls engine speed when running with the output breaker open and AC kW when synchronized with the GRID. For local control, the DG Volt. Reg. & Gov. Selector Switch in the Main Control Room must be in the LOCAL position.

d. Generator Voltage: LOWER-RAISE. Controls DG output voltage when the output breaker is open, and AC KVARS when synchronized with the Grid. For local control, the DG Volt. Reg. & Gov. Selector switch in the MCR must be in the LOCAL position.

e. Voltage Regulator (selector): MANUAL-OFF-AUTO. In MANUAL, the operator controls generator field excitation current using the MANUAL VOLTAGE CONTROL UNIT. In AUTO, the voltage regulator senses generator terminal voltage and adjusts generator field excitation current to maintain the voltage setting of the voltage regulator.

f. Engine Lockout Relay: NORMAL (blue lamp)-TRIPPED (amber lamp).

g. Generator Field Lockout Relay: NORMAL(green lamp)-TRIPPED(red lamp).

h. Local Engine Start Pushbutton-starts the DG when depressed. The DG Start Selector Switch in the MCR must be in the LOCAL position.

i. Local Engine Stop Pushbutton-stops the DG when depressed. The DG Start Selector Switch in the MCR must be in the LOCAL position.

j. Emergency Stop Pushbutton-stops the DG and trips the 86 & 41 lockout relays.

k. Immersion Heater (2); Off-On. When turned On, the immersion heaters on each engine cycle on and off to maintain coolant temperature between 125 to 155 degrees-F.

l. Lube Oil Pump (2); Off-On. When turned ON, the AC Circulating and Turbo-Soakback pumps on each engine will run continuously. When turned off, the DC pumps will turn on.

m. Manual Fuel Prime Pushbutton. Operates the DC motor driven Fuel Priming Pump.

n. Division 1 & 2 Diesel Generators are equipped with Synchrocheck relays that prevent the Diesel Generator output breaker from closing where paralleling with more than a 20 degree phase differential.

The Div. I and II generators are each equipped with heater coils that are normally energized during standby conditions in order to warm generator windings. This prevents the accumulation of moisture in the winding insulation due to high humidity in the DG room air. The heater coils automatically de-energize if the associated diesel generator set receives a start signal.. The heaters will also be automatically energized upon shutdown of the diesel generator units. Hand switches are not provided because control of the heaters is fully automatic and accomplished by auxiliary contacts from the engine cooling auxiliary control setup and pilot relays. The Division III DG has a control switch to operate the generator heater in automatic or manual.

2. Division III

The Div. III generator is rated at 2200 kW, 2750kVA, 4160 volts, 382 amps, 0.8 power factor, 60 Hz at 900 RPM, 8 poles. Div. III generator has a horizontal brush less exciter rated for 25 kW and 125 volts at 900 RPM.

A voltage regulator that controls exciter field current varies generator output. Generator output voltage is fed to the regulator through a regulating transformer and switch. When the voltage regulator is in AUTO the generator output voltage is sensed by the voltage regulator and used to control exciter field excitation. When the voltage regulator is placed in MANUAL generator output voltage is rectified and applied directly to the exciter field. In MANUAL the voltage regulator is bypassed and there is no automatic regulation of generator output voltage. (Procedures will dictate whether or not to use the manual voltage control).

When the generator is paralleled with off-site power the voltage regulator has built in voltage droop that allows the generator to share reactive loads. When the generator is powering it's associated buss after a loss of off site power, the voltage droop is set to zero to maintain vital functions throughout the load range.

The principal differences between the Div. III DG and Div. I & II DG's are:

a. Div. III DG is has a single 16 cylinder engine

b. Div. III can be synchronized from the local control panel*

c. Div. III has a different type of governor

d. Local control panel layout is substantially different.

e. Div III does not have an idle start.

- (Note: per the operating procedure, DG's shall not be operated in parallel with off site power sources from the local control panels. This is due to the lack of local instrumentation necessary to support parallel operations.)

Major Instrumentation — [.1.5.1]

a. DG Frequency

b. Incoming Voltage

c. Bus Frequency

d. Running Voltage

f. Synchroscope (SLOW-FAST) with sync lights

g. Diesel Generator Voltage-AC Volts

h. Generator Load Current-AC Amps

i. Bus Voltage-AC Volts

j. Normal Power Voltage-AC Volts

k. Generator Load Power-AC Kilowatts

l. Generator Reactive Load – AC VARS

m. Exciter Field Voltage-DC Volts

n. Exciter Field Current-DC Amps

o. Engine Running Time-Hours

Control and Interlocks

LOCAL ENGINE CONTROL PANEL CONTROLS: **[.1.4.11]**

a. Engine Control Switch: Three-position switch - MAINT, AUTO and TEST. In AUTO, the DG responds to all manual and automatic start and load commands. In MAINT, the DG will not start or load. The TEST position allows local starting of the DG.

b. Governor: RAISE-LOWER. Controls engine speed when running with the output breaker open and AC kilowatts when synchronized with the GRID. For local testing the DG Volt. Reg. & Gov. Selection Switch in the MCR must be in the LOCAL position.

c. Generator Voltage: LOWER-RAISE. Controls DG output voltage when the output breaker is open, and AC KVARS when synchronized with the GRID. For local testing the DG Volt. Reg. & Gov. Selector Switch in the MCR must be in the LOCAL position.

d. Voltage Regulator (selector): MANUAL-OFF-AUTO. In MANUAL, the operator controls generator field excitation current using the MANUAL VOLTAGE CONTROL UNIT. In AUTO, the voltage regulator senses generator terminal voltage and adjusts generator field excitation current to maintain the voltage setting of the voltage regulator.

e. Engine Lockout Relay (86): NORMAL(white lamp)-TRIPPED(amber lamp).

f. Generator Lockout Relay (86G): NORMAL (blue lamp)-TRIPPED(lamp out).

g. Local Engine Start Pushbutton-starts the DG when depressed. The DG Start Selector Switch in the MCR must be in the Diesel Room position or Local Engine Control switch in TEST.

h. Local Engine Stop Pushbutton-stops the DG when depressed. The DG Start Selector Switch in the MCR must be in the Diesel Room position.

i. Emergency Stop Pushbutton-stops the DG and trips the 86 & 41-86G lockout relays.

j. Bus Synchronizing switch.

k. Normal Synchronizing switch.

l. DG 1C Brkr 252 – DG1C Control: Trip-Close

m. Normal Breaker Control; Trip-Close

n. DG 1C Safety Reset Pushbutton. Must be pushed before resetting the 86 Lockout Relay.

o. Manual Generator Voltage Adjust potentiometer: Allows DG output voltage adjustment in MANUAL CONTROL

p. Division III Diesel Generator is equipped with Synchrocheck relays that prevent the Diesel Generator output breaker from closing when paralleling with more than a 20-degree phase difference. There is no synchrocheck relay protection when paralleling the Division III DG from the Local Panel.

3. Output Breaker

DG output breaker control is discussed in detail in the Aux Power Lesson plan. The DG output breakers are controlled normally from the MCR and can be manually manipulated in an emergency like any 4.16 kV circuit breaker. Only the Div. III output breaker can be synchronized with an energized bus from outside the MCR.

Major Instrumentation

None

Controls and Interlocks

The DG output breakers will open on any diesel engine trip and will also open if:

a. DG running in parallel with offsite power source and a LOCA signal occurs. [.1.15.6]

b. DG running in parallel with offsite power source and DG output breaker sync switch is turned off. [.1.15.1]

c. DG running in parallel and a LOOP occurs. The offsite power source breakers will trip on under voltage and the Div. I & II DG output breakers trip. If both Div. I & II DG output breakers trip, all non-emergency loads will shed and the DG will re-energize the associated divisional 4.16 kV bus. The Div. III DG output breaker will remain closed and continue to power the Div. III 4.16 kV bus.

C. Diesel Generator Protective Devices

The DGs are equipped with several devices that initiate protective trips of the engine and generator. These circuits are designed to prevent DG operation under potentially harmful or hazardous conditions. [.1.8.1]

The following conditions produce DG trips:

- Engine Overspeed
- Engine Over crank (considered a failure to start, but does cause the lockout relay to trip)

- Low Lube Oil Pressure
- High Water Jacket Temperature
- Reverse Power
- Loss of Excitation
- Over current
- Generator Ground Fault (Div. I and II only)
- Differential Current

All of the safety circuits operate by actuating a relay that, in turn trips the 86-lockout relay. This causes the governor dump solenoid to energize; which drains the hydraulic oil from the governor's power piston, which drives the fuel injector rack to the no-fuel position: Thus, starving the engine of fuel. Additionally, tripping the 86-lockout relay will cause the Generator field and Output breakers to open (41 relay lockout). All of the safety trips are bypassed on a LOCA signal "EXCEPT" engine overspeed, (overcrank for Div I and Div II only) and generator differential current trips.

[.1.15.6] [.1.8.2]

1. Engine Overspeed Trip

   The mechanical overspeed trip mechanism on each engine will operate to prevent the injection of fuel into the cylinders if engine speed reaches 1035 RPM (+10/-20). The overspeed trip device is incorporated into the camshaft counterweight and consists of a flyweight held in place by an adjustable tension spring. Spring tension is adjusted to hold the flyweight until speed exceeds the trip setpoint. This causes the flyweight to move outward and contact the trip lever. Actuation of the trip lever causes an actuating spring to rotate the trip shafts that extend the length of each engine bank. This causes the trip shaft cams to contact and raise the injector rocker arm pawl contact on its cam. This mechanically prevents injection of fuel into the cylinders and causes the engine to shutdown.

   [.1.8.1] [.1.11.2]

   The overspeed trip mechanism must be manually reset following an overspeed trip for the engine to be restarted. To reset the overspeed trip, the trip lever must be rotated counterclockwise to the 9 o'clock (approximately) position.

This causes the trip lever to latch in place until an overspeed condition occurs.

In addition to the mechanical overspeed trip mechanism, each engine is equipped with an electrical roller-type limit switch that trips the 86 lockout relay. This shuts down the engine and trips the DG output breaker. This electrical limit switch also ensures tripping of both 12 and 16 cylinder engines when an overspeed condition is sensed on one of the two tandem Div. I or II DG's.

2. Engine Over crank

The starting circuitry of each engine is equipped with over crank time delay relays that will stop the air start motors after a certain length of time. The over crank relays energize the 86 lockout relay preventing additional DG start attempts until locally reset. The Div. I & II over crank relays terminate engine cranking 10 seconds after initiation. Div. III over crank relay terminates engine cranking after 20 seconds.

[.1.8.1] [.1.11.3]

3. Low Oil Pressure

Declining lube oil pressure causes shutdown of the diesel engines at the following setpoints:

[.1.8.1] [.1.6.2] [.1.11.4]

Div. I and II engines	19 psig
Div. III engine	17.21 psig

4. High Coolant Temperature

Increasing jacket water temperature shuts down the diesel engines at the following setpoints:

[.1.8.1] [.1.11.5] [.1.6.10]

Div. I & II engines	205°F
Div. III engine	208°F

(Note that for the Div. I and II DG's a low lube oil pressure or high coolant temperature condition in either engine will result in a simultaneous trip of both engines.)

5. Reverse Power

The Div. I, II and III DG's will trip on reverse power in order to prevent "motoring" the generator.

[.1.8.1] [.1.11.6]

6. Loss of Excitation

   The Div. I, II and III DG's trip on loss of generator field current (excitation). Loss of excitation relays are energized when generator field current is interrupted initiating a trip of the engine by the (86) lockout relay. As previously discussed, tripping the 86-lockout relay will also trip the DG field and output breakers.

   [.1.8.1] [.1.11.7]

7. Over-current (Phase)

   An over-current condition will trip both the diesel engine(s) and the DG output breaker. There are individual phase over-current relays for each phase on the local DG control panel.

   [.1.8.1] [.1.11.8]

8. Generator Ground Fault

   [.1.8.1] [.1.119]

   The Div. I and II DG's have ground fault detection circuitry that initiates a trip if a short circuit to ground occurs.

9. Differential Current

   [.1.8.1] [.1.11.10]

   Excessive phase-to-phase Current difference will trip and the Diesel engine and associated output breaker.

Major Instrumentation

Crankcase Pressure Device

Div. I, II and III crankcase pressure detectors produce an alarm but do not trip or prevent starting of any DG. The crankcase pressure detector detects positive engine crankcase pressures. The crankcase eductor should maintain a negative crankcase pressure during operation. Crankcase pressure may become positive due to compression cylinder blow-by, a crankcase explosion, excessively high crankcase oil level, blockage in the crankcase eductor, or an airbox leak into the crankcase. Operators are cautioned in the local annunciator response procedure not to open any handhole or cylinder top deck covers until the DG has been shutdown for at least two hours following a high crankcase pressure condition. This avoids admitting air to the crankcase under potentially explosive conditions in the engine crankcase. The crankcase pressure device is locally mounted on the accessory end of each DG. A small plunger will pop out exposing a RED-ORANGE collar when it actuates.

[.1.6.13] [.1.11.1]

Control and Interlocks

None of the crankcase pressure devices produce engine trips.

All crankcase pressure devices actuate the local alarm annunciator panel which repeats in the MCR. No automatic actions occur, but DG should be shutdown if conditions permit.

Div 1, 2 alarms at 0.8 to 1.8" H_2O — **[.1.11.1]**

Div 3 alarms at 1.9" H_2O

Main Control Room Controls

All three divisional DG's have similar MCR instrumentation and controls. — **[.1.5.1]**

Major Instrumentation

1. 4160 V Bus Running Voltage (0-5250 VAC)
2. 4160 V Bus Incoming Voltage (0-5250 VAC)
3. Frequency (55-65 Hz)
4. DG Output Voltage (0-5250 VAC)
5. DG Output Current (0-4000 amps): use 'B' phase only for surveillance data.
6. Generator Reactive Load (-3500 to +3500 KVARS)
7. Generator Power (0-5800 kW)
8. 4160 V Bus Synchroscope (Slow-Fast)
9. Fuel Oil Storage Tank Level (0-100%)

Control and Interlocks

1. DG Control Switch (STOP-AUTO-START)
2. DG Start Selector Switch (CONTROL ROOM-DIESEL ROOM)
3. DG Governor (RAISE-LOWER)
4. DG Voltage Regulator (RAISE-LOWER)

5. DG Voltage Regulator and Governor Select Switch (CONTROL ROOM (Remote/Local)

6. Offsite Power Source Permissive Pushbutton

7. DG Emergency Stop Pushbutton

8. DG Fuel Oil Transfer Pump (PULL TO LOCK-STOP-AUTO-START)

9. DG Output Breaker (PULL TO LOCK-TRIP-AUTO-CLOSE)

10. DG Output Breaker Sync Switch (ON-OFF)

11. DG Output Voltage (Phases) (OFF-AB-BC-CA)

Interim Summary:

Review Components Section:

- **Diesel Engine Major Components**
- **Generator**
- **Protective Devices**

Request clarification on questions that may arise during review.

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D. Fuel Oil System

1. Fuel Oil Storage Tanks (FOST)

The function of the Fuel Oil Storage and Transfer system is to store and supply a sufficient quantity and quality of diesel fuel oil to operate the Division I, II and III DG's for 7 days while supplying the maximum post LOCA load demand. The 7 day period is sufficient time to place the unit in a safe-shutdown condition and to bring in replenishment fuel from an offsite location. The Division I, II and III fuel oil Storage Tanks are located in separate rooms in Diesel Generator Bldg 712'. Div. I and II fuel oil storage tank design capacity is 54,000 gallons. The Div. III fuel oil storage tank capacity is 36,000 gallons. DG fuel oil may be purchased with a fuel energy rating by the American Petroleum Institute rating of API 32-38 (with API 38 having less energy).

[.1.5.6] [.1.14]
Figure 16

Due to Div 1 DG electrical loading requirements, insufficient fuel oil reserve margin was present. Thus with lower energy (API) fuel oil allowed to be loaded, Div 1 DG FOST level is required to be maintained higher to comply with 7-day ITS requirement;.

The Technical Specification 7-day minimum fuel oil requirements are:
Division I = 51,000 gallons. Div. 1 D/G has higher LOCA electrical loading, thus a higher fuel oil quantity is need. The ITS 6-day limit for Div. 1 D/G is 43,810 gal.

Division II = 45,000 gallons Div. 2 D/G has a lower LOCA loading than Div. 1 D/G. The ITS 6-day limit is 38,572 gal.

Division III = 29,500 gallons. The ITS 6-day limit is 25,286 gal.

Fuel arrives on site by tanker truck and is delivered to an outside fill station located at the south end of the DG building. The fill station has a heavy bolted down cover which allows access to a locked close fill valve and blank flange connection for each divisional fuel oil storage tank. Any liquid accumulation in the fill station drains to the DG building Floor Drain system.

If Storage Tank draining is required, a temporary air operated pump can be attached to the storage tank drain line and discharged back through the fill line by removing the return line strainer. This will allow a flow path from the tank to the fill station. The installed Fuel Oil Transfer Pump can also achieve this flow path.

Figure 19

Major Instrumentation

A fuel oil storage tank level transmitter provides a low fuel level alarm on the local engine control panels and a fuel oil storage tank level indication for Div. I, II, and III DG's on 1H13-P877.

[.1.6.6]

Control and Interlocks

NONE

A Biocide is added to the DG fuel oil storage tanks to prevent fouling of the fuel oil system components due to bacterial growth and contamination. Operators add Biocide to received fuel oil. Handling a small amount of biocide out of doors does not necessitate respiratory protection.

Kathon FP1.5 Biocide is classified as a hazardous material according to 29CFR1910.1200. It is a SEVERE IRRITANT. Protective clothing made of butyl rubber or nitrile including gloves and apron should be worn to avoid skin contact. Inhalation of vapor or mist can cause irritation of the nose and throat. Eye goggles or a face shield are required during handling of Biocide. Eye contact can cause severe irritation and possible corneal injury. Skin effects may be delayed for hours, and can cause severe skin irritation and burns. Delayed effects include allergic contact dermatitis. Biocide is harmful if swallowed.

If fuel oil should come in contact with the skin, flush the affected area thoroughly with soap and water. If fuel oil should come in contact with the eyes, immediately flush the eyes thoroughly with water and notify Security and/or Chemistry Management.

2. Fuel Oil Transfer Pumps

The Div. I, II and III fuel oil transfer pumps are 1HP, 460 VAC rotary screw, positive displacement type pumps with a capacity of 13 gpm at 50 ft discharge head. The transfer pumps are located on Diesel Generator Building 712' elevation. Each transfer pump takes suction on the associated Div. I, II and III fuel oil storage tanks and discharges to the associated fuel oil day tank. The discharge capacity of the Fuel oil transfer pump exceeds anticipated diesel engine fuel consumption. Surveillance testing is done on the fuel oil transfer pumps to ensure sufficient capacity. When the engine is running the transfer pumps automatically start and operate continuously with the day tank overflowing

[.1.2.2] [.1.5.8] [.1.3.2]

back to the storage tank. The pumps may also be operated manually from the control room.

Major Instrumentation

Each fuel oil transfer pump has one suction, and two discharge pressure indicators locally mounted.

[.1.6.8]

Control and Interlocks

Fuel oil transfer pumps will automatically start when the local panel control switch is in AUTO:

- When the DG's start.
- To maintain fuel oil day tank level automatically when the DG is shutdown.

3. Fuel Oil Day Tanks (FODT)

The fuel oil day tanks are located on Diesel Generator Building 737' in the respective DG rooms. The Diesel Fuel Oil Day Tanks are designed to store a sufficient quantity of diesel fuel oil to operate the Division I, II and III DG's for a minimum of 1 hour at maximum post LOCA loads (ITS requirements are 385 gals for Div 1 & 2, 240 gals for Div 3). Each day tank has a design capacity of 731 gallons. This is sufficient for approximately 2 hours of engine operation at less than max. LOCA loading without makeup. Each day tank has an overflow line that drains back to the associated fuel oil storage tank. When the fuel oil transfer pump is operating the day tanks overflow to the fuel oil storage tank.

[.1.2.2] [.1.5.7] [.1.6.7] [.1.14]
Opt: EC Eval 366167 and EC 366152 R1 requires an administratively controlled minimum FODT level as follows:
Div. 1: $\geq$ 60%
Div. 2: $\geq$ 60%
Div. 3: $\geq$ 67.5%
The EDG will be INOP (<minimum required volume if its associated FODT level drops below:
Div. 1: <54%
Div. 2: <54%
Div. 3: <35%
FODT level is controlled at or above the admin limit for top of priming pump suction concerns. If level drops below the admin limit, fill the tank above the limit and perform an operability determination.

Major Instrumentation

Level transmitter

Local level indicator in Day Tank room

Control and Interlocks

The Level transmitter provides the following:

- Low level alarm on the local control panel
- Auto start/stop of the fuel oil transfer pump to maintain fuel oil day tank level when the control switch is in AUTO and the DG is shutdown.

4. DC Fuel Oil Priming Pumps

The DC motor driven fuel-priming pump is automatically started when the DG starts. This primes the fuel oil lines during engine starts. The priming pump operates in parallel with the engine driven fuel pump. The priming pump ensures sufficient fuel is supplied to the fuel injectors as the DG accelerates to operating speed. When the Div. I and II engines reach 850 RPM, the priming pumps automatically stop. The Div. III priming pump operates continuously when the Div. III engine is started.

[.1.2.2] [.1.4.6]

Major Instrumentation

Fuel priming pump discharge pressure gage. When fuel priming pump discharge pressure is stable for one minute the engine is assumed to be primed.

Control and Interlocks

Manual fuel prime pushbutton:

- Div. I & II is on local engine control panel and has RED (running) and GREEN (stopped) lights
- Div. III is on the engine gauge board and has no indicating lights

Note: The Diesel Generator shall not be primed by use of the manual fuel prime pushbutton immediately prior to a surveillance test. This could precondition the Diesel Generator to start. Priming is permitted following maintenance on the DG.

5. Engine Driven Fuel Oil Pump

The engine driven fuel oil pumps for both the 12 and 16 cylinder engines are 4.5 gpm, positive displacement gear pumps. Each fuel pump takes suction on the day tank and supplies fuel to the injectors through a duplex fuel filter. The engine mounted fuel pumps are mounted on a common shaft with the scavenging oil pump and driven by the engine accessory gear train.

[.1.2.2]

Major Instrumentation

Fuel oil supply and return header pressure gages are located near the fuel oil duplex filter.

Control and Interlocks

NONE

6. Fuel Oil Filters

The engine mounted, duplex fuel filter removes particulate contamination from the fuel oil to prevent clogging of the fuel injectors. Either filter may be selected for use by operating the selector lever mounted on the filter. Normally only one filter is in-service at a time; but both filters can be placed in service simultaneously by placing the selector lever in the mid position. During engine operation, either filter may be changed out provided the selector lever is positioned to direct fuel oil to pass through the other filter.

[.1.2.2]

Major Instrumentation

Fuel oil supply and return header pressure gages.

Control and Interlocks

Trouble DG1A, 1B, 1C alarms in the MCR when the FUEL FILTER RESTRICTED (50 psid) alarms on the local control panel.

E. Engine Starting Air System

Figures 18 & 19
[.1.4.5] Optional

The function of the starting air system is to start and accelerate the divisional DG's so that they achieve rated voltage, frequency and may be loaded within 12 seconds of the DG start signal.

1. Air Compressors

The Div. I, II and III air start systems are equipped with redundant, locally mounted air compressors. The DG starting air skids are located on 737' elevation DG building. Both compressors in the Div. I, II and Div. III systems are AC motor driven.

[.1.5.3]

Major Instrumentation

RED-AMBER-GREEN on-tripped-off air compressor control switches on the local engine control panel.

Starting air receiver pressure switches.

Control and Interlocks

Three position HAND-OFF-AUTO air compressor control switches. In HAND the compressor will continue to run in spite of receiver pressure. In AUTO an air receiver pressure switch controls the compressor. [.1.6.9]

Div. I & II compressors automatically start at 215 psig, and stop at 250 psig in the associated starting air receiver.

Div. III compressors automatically start at 225 psig, and stop at 240 psig in the associated starting air receiver.

2. Starting Air Dryers

There is a separate air dryer skid for each divisional DG. Each air start system is provided with an automatic air dryer located at the 737' elevation in the corresponding DG Building room. Each dryer is equipped with dual drying chambers that are alternately cycled through 10 minute drying and regeneration periods. One of the chambers is on line when either of the associated air compressors is running. Flow is not interrupted while switching over to the alternate drying chamber. The air dryer chambers are filled with an active alumina desiccant and equipped with a visual moisture indicator. The moisture indicator contains a gel that turns blue when the gas is dry and pink or any color other than blue when it is wet. An air dryer performance test is done every quarter. This is accomplished by inserting a Dew Point Hygrometer in the same location as the moisture indicator. During operation at equilibrium conditions the dryer is capable of producing dry air with a dew point of -40°F. [.1.4.5] [.1.5.5

DG air start system air dryers are critical in preventing degradation of the air start system and should be maintained in service whenever the air start system is in service. Additionally, maintaining a relatively moisture free air start system allows extension of the air start motor rebuild frequency to every four years. If it is necessary to place the air dryers out of service due to failure or malfunction, 1) an Issue should be immediately written and work scheduled expeditiously to minimize the amount of time the air dryers are out of service; 2) evaluate whether earlier rebuild of air start motors is necessary.

Major Instrumentation

Each dryer skid has a separate pressure gage for each desiccant tower.

Each dryer skid has a common outlet pressure gage on the desiccant tower outlet.

Control and Interlocks

The starting air dryer skids will automatically alternate drying towers when the dryer skid is in run, and either starting air compressor is in run.

3. Air Receiver Tanks

The Div. I, II and III redundant air receiver tanks are located on 737' elevation in the corresponding Diesel Generator room. Each air receiver provides enough air to accelerate the associated diesel engine to starting speed (approximately 150 RPM) five times in succession without recharging the receiver. All three receivers are equipped with overpressure relief valves: 275 psig for Div. I and II, and 250 psig for Div. III.

[.1.5.4] [.1.4.5]

Major Instrumentation

Pressure switches control

Control and Interlocks

Opt: The rated air capacity is 93 ft3 at 250 psig for the Division I and II DG's; and 64 ft3 at 240 psig for the Division III DG.

Pressure switches control starting and stopping of the starting air compressors.

Div. I & II starting air compressors start on receiver pressure of 215 psig decreasing, and stop when receiver pressure reaches 250 psig.

Div. III starting air compressors start on receiver pressure of 225 psig decreasing, and stop when receiver pressure reaches 240 psig.

4. Air Start Solenoids

The Div. I, II and III air start solenoids provide the interface between the DG starting control logic and the engine air starting system. The air start solenoids are energized by divisional 125 VDC when the DG starting logic is actuated.

Figures 18 & 19

[.1.4.5]

The solenoids have manual override provisions allowing local control if a loss of 125 VDC occurs. When the Div. I and II air start solenoids energize they allow air from the starting air header to actuate and open the both main air start valves. This provides a flowpath for air from the starting air receivers to the air start motors. When the Div. III air start solenoids energize they direct air to the lower air start motors of each air start motor pair. This engages the air start motor pinions on the lower air start motors. When the pinions on the lower air start motors engage, air is ported to engage the pinions of the upper air start motors. When the upper air start motor pinions engage air is ported to actuate the main air start valve for that pair of air start motors. The air start solenoids also provide piloted air to the booster servomotors on each engine to drive the electro-hydraulic actuators on each engine to the maximum fuel position during starting.

Major Instrumentation

NONE

Control and Interlocks

Powered from Divisional 125 VDC.

Controlled by DG starting control logic.

5. Main Air Start Valves

The Div. I, II and III main air start valves complete the DG starting air flowpath from the starting air receivers to the air start motors. **[.1.2.3]**

Major Instrumentation

NONE

Control and Interlocks

Pneumatically controlled by the starting air solenoid valves.

6. In-Line Oilers

Oilers are installed in the air lines just upstream of the air start motors and release an oil-air mist that lubricates the air start motors during engine cranking. The oilers are passive "venturi" type devices that require airflow through them in order to function. As starting air passes through the oiler, oil **[.1.2.3]** is drawn through a siphon tube from the oil bowl and enters the air line via a needle valve. The airflow diffuses the oil into a mist, as it passes through the needle valve, and carries it into the air start motors.

Major Instrumentation

NONE

Control and Interlocks

NONE

7. Air Start Motors

The Div. I, II and III diesel engines are cranked by engine skid mounted air start motors. The Div. I and II diesels have 3 Pow-R-Quik air start motors per engine. The air start motors are arranged such that at least one of the motors on each engine is fed from the alternate air receiver. During normal engine cranking all six motors on the diesel generator set are used, but only three motors are actually required to turn the engines over. **[.1.2.3]**

The Div. III diesel engine has two redundant pairs of Ingersoll-Rand air start motors. Either pair is capable of starting the engine, but both pairs are used during normal engine cranking.

If an air start motor pinion fails to disengage after a DG is started it will make a loud, high pitched whining noise. In a non-emergency condition the DG would be shutdown and the air start motor repaired. In an emergency condition the engine remains in service. This would probably destroy the failed air start motor, but the DG would continue to operate. The redundant air start motors could accomplish subsequent emergency starts. **[.1.10.7] [.1.15.7]**

Major Instrumentation

NONE

Control and Interlocks

Actuated by starting air flowing through the main air start valves.

F. Combustion Air Intake

The combustion air intake system provides clean, dry, filtered air for combustion with fuel oil in the DG combustion cylinders. **Figure 6**

1. Air Intake Filters **[.1.4.7]**

   Each diesel engine is equipped with a skid mounted, dry paper type air filter/silencer that removes particulates from the incoming combustion air. The filters for the 12 cylinder engines are rated for 7100 scfm at 90°F. The 16 cylinder engine filters are rated at 9404 scfm at 90°F.

   Major Instrumentation

   Locally mounted D/P indication **[.1.6.12]**

   Control and Interlocks

   NONE

G. Engine Exhaust System

The diesel engine exhaust system provides the flowpath for removal of combustion exhaust gasses from the divisional diesel engines to the Diesel Building Roof. **[.1.2.4] [.1.4.8] [.1.3.4]** **Figure 8**

1. Engine Exhaust Manifold **[.1.6.4]** **Figure 6**

   The exhaust manifold directs the hot exhaust gases through the turbocharger to the exhaust piping. The exhaust manifold is comprised of chamber assemblies, expansion points and an adapter assembly. The adapter assembly contains a stainless steel screen and trap that prevents foreign particles from entering the turbocharger.

   Major Instrumentation

   Temperature of each combustion cylinder exhaust is monitored by a multipoint pyrometer. Indicating range is 0-1200 °F. There is a cylinder exhaust pyrometer on the engine gauge board for each diesel engine.

Control and Interlocks

NONE

H. Lube Oil System

1. Main Lube Oil and Piston Cooling Pumps

Figure 7 & 20

[.1.2.1] [.1.4.4]

The main lube oil and piston cooling pumps have a common housing and are separated by a space plate between the sections of the pump body. Both pumps are positive displacement helical gear pumps, with individual oil inlet and discharge ports. Both pumps are driven on a common shaft powered by the accessory drive gear train.

The main lube oil pump supplies oil to most of the engines moving parts. The main lube oil pump takes suction on the strainer sump and discharges to the main lube oil manifold. The main lube oil manifold extends axially the full length of the engine. Taps in the main lube oil manifold supply lubrication to the crankshaft and main bearings, camshaft/turbocharger and accessory drive gear trains, camshafts and cylinder rocker arms, and the crankcase overpressure device. Main lube oil pump capacity for the 12 and 16 cylinder engines is 157 gpm and 185 gpm respectively.

Recall: Each DG engine oil sump contains an inventory capable of supporting a minimum of 7-days at full load operation. (347/284 gals. 16/12 cyl. Engine).
ITS 6-day minimum lube oil supply for each 16 cylinder diesel engine is 327 gallons and for each 12 cylinder diesel engine is 269 gallons. Ref. EC 330661

The piston-cooling pump takes suction on the strainer sump also, and discharges to the two piston cooling manifolds. The piston cooling manifolds extend the full length of the engine. A piston cooling oil pipe at each cylinder directs a stream of oil through the piston carrier to cool the underside of the piston crown and ring belt.

Normal DG lube oil standby temperature is approx. 120 deg.F, Minimum temp is 85 deg. F.

Piston cooling pump capacity for the 12 and 16 cylinder engines is 66 gpm and 92 gpm respectively.

Major Instrumentation

Main and Piston Cooling Oil supply header temperature gages are located on the accessory end of each DG.

[.1.6.1]

Control and Interlocks

Main and piston cooling oil header pressures are not adjustable. The operating oil pressure is determined by manufacturing tolerances, oil temperature, oil dilution, wear, and engine speed. The minimum oil pressure is 8-12 psig at engine idle speed, and 25-29 psig at full speed. A pressure relief valve that relieves at 125 psig prevents Main and piston cooling header overpressure.

2. Scavenging Oil Pump

The scavenging oil pump is helical gear pump driven from the accessory gear drive train. The scavenging oil pumps for the 12 and 16 cylinder engines are rated at 279 gpm and 390 gpm respectively. The scavenging oil pumps take suction on the oil pan sump through the oil strainer in the oil pan sump. The scavenging oil pump discharges through the lube oil filters, the lube oil cooler, and the lube oil strainer assembly filters prior to returning to the lube oil strainer assembly sump. This provides cool, clean, filtered oil to the suction of the main and piston cooling oil pumps that take suction from the lube oil strainer assembly strainer sump during engine operation. The scavenging oil pump must operate and pressurize the strainer assembly to supply oil to the main and piston cooling oil pumps. The main and piston cooling oil pumps are physically located above the oil pan sump, scavenging oil pump and strainer assembly. The oil supply to the main and piston cooling oil pump suction will be lost if the scavenging oil pump fails to pressurize the strainer assembly. This will result in loss of oil to the main and piston cooling oil manifolds and represents a strong potential for damage to the lubricated engine components.

[.1.2.1] [.1.4.3] [.1.6.2]
Figure 8

Major Instrumentation

Local discharge pressure gage located on accessory end of DG.

Control and Interlocks

NONE

3. Circulating Oil Pump

The AC motor driven, gear type, circulating oil pump normally runs continuously. The circulating oil pumps should be manually started if not running when the diesel engine is shutdown. This circulates oil from the oil sump through the oil filter and cooler. The lube oil cooler acts as a heater when the engine is shutdown because an electric heater warms the jacket water circulating through it. The warm oil prelubes the diesel and keeps it warm (approximately 110°F-130°F). This enables faster starts and reduced engine wear during rapid starts.

[.1.2.1] [.1.4.2]
Figure 20

A DC motor driven circulating oil pump provides backup for the AC driven pump. The DC pump auto starts on loss of AC power to the AC circulating oil pump. The capacity of each AC motor driven pump on the 12 and 16 cylinder engines is 6 gpm, while the capacity of the DC motor driven pumps is 3 gpm.

Major Instrumentation

RED-GREEN indicating lights above the control switch on the local engine control panel.

Control and Interlocks

ON-OFF control switch on the local engine control panel.

4. (Turbocharger) Soakback Oil Pumps

The AC motor driven, gear type soakback oil pump provides oil to the diesel engine's turbocharger when it is shut down. The soakback oil pumps should be manually started if not running when the diesel engine is shutdown. This circulates oil from the oil pan sump through the soakback filter to the turbocharger to provide prelubrication and remove residual heat. A DC soakback pump backs up the AC pump similar to the DC circulating oil pump. The capacity of the AC and DC driven pumps is 3 gpm.

[.1.2.1] [.1.4.1]
Figure 20

Major Instrumentation

RED-GREEN indicating lights above the control switch on the local engine control panel.

Control and Interlocks

ON-OFF control switch on the local engine control panel.

5. Lube Oil Strainers

There are three strainers in the main lube oil strainer housing which is locally mounted, one scavenging oil strainer and two main lube oil strainers. The main lube oil strainers are equipped with replaceable filter elements consisting of pleated, perforated metal cores covered with mesh screening and enclosed in metal cylinders. The cylinders prevent element collapse due to high D/P and provide a constant head of oil to the strainer.

(Figures 11 & 12)
[.1.2.1]

When the DG requires oil to be added to the sump, it is added through the square strainer box cover. Once the oil is sampled, a portable lube oil pump designated for "EMD Diesel Lube Oil Only" is used to transfer the oil from storage drums to the strainer housing.

Major Instrumentation

NONE

Control and Interlocks

The lube oil strainer has two maintenance valves internal to the strainer housing. Both valves are normally closed. One valve drains the lube oil filter assembly, and the other drains the lube oil strainer assembly.

6. Lube Oil Filter

The lube oil filter is a seven element, full flow, cartridge filter. Oil circulates through baffles in the strainer housing to the outside of the filter elements. Lube oil filters through seven pleated paper cartridge filters into the discharge compartment. Oil flows out of the filter housing into the lube oil cooler.

[.1.2.1]

Major Instrumentation

There is a 3/4" sightglass on the side of the lube oil filter.

[.1.6.3]

Control and Interlocks

There is an internal bypass valve that bypasses the filters on elevated differential pressure. This bypass valve starts to open at 30 psid and becomes fully open at 40 psid. This maintains oil flow when the filters are clogged or the oil is cold.

7. Lube Oil Cooler

The local skid mounted lube oil cooler is a shell and tube type heat exchanger that cools engine lube oil during operation and warms it during periods of standby. The lube oil cooler is cooled by jacket water during operation, and it's also warmed by heated jacket water during standby. [.1.2.1]

Major Instrumentation

Outlet temperature gage between the Lube Oil cooler and the Lube Oil strainer assembly [.1.6.1]

Inlet temperature gage between the scavenging oil pump and the Lube Oil cooler

Control and Interlocks

None

8. Lube Oil Separator

The lube oil separator for each diesel engine is mounted on the turbocharger housing and contains a screen element. An ejector, mounted on the separator cover, is connected to the exhaust stack eductor by a flexible tube. Pressurized air passes through the ejector drawing engine oil vapors through the screen element, while the eductor tube in the turbocharger turbine exhaust also directs oily vapor through the screen. The oil collects on the screen and drains back the engine. In this manner, the ejector assembly maintains a slight vacuum (3-5 inches H_2O) on the engine crankcase. If the screen were to clog or malfunction it could cause high crankcase pressure. [.1.6.13]

Major Instrumentation

NONE

Control and Interlocks

NONE

9. Gallery Sightglasses

The gallery sightglasses are checked during DG pre-starts to ensure enough oil but NOT enough to get above the pistons that could cause a Hydraulic lock on the piston during start and damage the DG. After start it is desirable to have oil flowing so both will be full. The gallery oil level upper sightglass may remain full as long as 24 hours when restoring the engine to Standby following a cold shutdown period (i.e., immersion heater turned off) or lube oil drain and refill. This is due to the time required to heat the oil and engine to standby temperatures.

I. Cooling Water System

The jacket water cooling system provides cooling to the combustion cylinder jackets, turbocharger aftercooler, and lube oil heat exchanger. A borate-nitrate based additive is used to minimize corrosion and scaling in the engine cooling/jacket water system. The additive is alkaline. Contact with the skin and eyes should be avoided. Required personal protective equipment includes gloves, a splash apron, and a face shield or goggles while handling the corrosion inhibitor per MSDS.

[.1.2.6]
Figure 21

1. Engine Cooling/Jacket Water Pumps

Each diesel engine has two centrifugal engine cooling/jacket water pumps. These pumps are driven from the engine's governor drive gear in the accessory gear drive train. Both pumps take a suction on the lube oil cooler outlet and discharge to separate jacket water manifolds. The water expansion tank is also connected to the suction side of the jacket water pumps. The 12 cylinder engine cooling water pumps are rated at 660 gpm at 50 psig. The 16 cylinder engine pumps are rated at 850 gpm at 60 psig. Pump outlet pressure is available on the local gauge panel for each DG.

Figure 21
[.1.4.10]

2. Inlet & Outlet Manifolds

The water inlet manifold distributes cooling water to the cylinder liners, cylinder head and after coolers. The outlet manifold directs warm water to the temperature regulating valve where flow is directed to either the lube oil cooler alone, or through the jacket water heat exchanger and the lube oil cooler, depending on engine return water temperature. **[.1.6.10]**

Major Instrumentation

There are Jacket water temperature gages in the inlet and return headers.

Control and Interlocks

There is a discharge pressure switch on the discharge on one of the two engine cooling water pumps on each engine. When engine cooling water pump discharge pressure exceeds 20 psig this pressure switch operates contacts which deenergize the air start solenoid valves. This prevents inadvertent starting of a DG that is running.

There are two jacket water return header temperature switches on each engine. On the Div. 1 & 2 DGs, one of the temperature switches will actuate the Engine 1 (2) High Coolant Temperature/Low Coolant Level annunciators at 195°F. The other temperature switch will trip the diesel engine if jacket water return temperature is allowed to reach 205°F. On the Division 3 DG, the high temperature coolant alarm switch will actuate at 200°F and annunciate the HIGH WATER TEMPERATURE annunciator. The other temperature switch will trip the engine at 208°F. The high coolant temperature trip is bypassed by the LOCA signal. **[.1.4.10]**

3. Jacket Water Heat Exchanger

The shell and tube type jacket water heat exchangers maintain water temperature at approximately 170°F by rejecting excess heat to the Shutdown Service Water System. If jacket water temperatures are sufficiently low, the jacket water will bypass the heat exchanger and pass only through the lube oil cooler.

[.1.6.10]

Major Instrumentation

Jacket Water Return Header Temperature on the inlet to the Jacket Water Heat Exchanger

Jacket Water Supply Temperature on the discharge of one of the two Engine Cooling water Pumps

Control and Interlocks

None

4. Jacket Water Expansion Tank

[.1.4.10] [.1.6.5] [.1.14]

Both the 12 and 16 cylinder diesel engines have 83-gallon expansion tanks. The expansion tanks are thermal expansion volumes, which absorb excess coolant as it thermally expands during engine operation. Expansion tanks are connected to the cooling water pump suction lines. The expansion tanks have pressure caps, which may be removed to add coolant and corrosion inhibitor to the engine cooling system.

Cooling water used in the Diesel Generator engines contains Nalco NALCOOL 2000, a liquid borate-nitrite based corrosion inhibitor. Nalco NALCOOL 2000 is alkaline. If cooling water should come in contact with the skin, flush the affected area thoroughly with soap and water. If cooling water should come in contact with the eyes, immediately flush the eyes thoroughly with water and notify Security and/or Chemistry Management.

Major Instrumentation

[.1.6.5]

Sight glass on the side of each expansion tank.

Control and Interlocks

[.1.4.10]

On the Division 1 & 2 DGs, the level switch actuates the Engine 1 (2) High Coolant Temp/Low Coolant Level annunciator for the applicable engine. On the Division 3 DG, the level switch actuates the LOW EXPANSION TANK WATER LEVEL annunciator. These local alarms repeat in the MCR as TRBL DG1A/1B/1C.

5. Immersion Heater

The immersion heater works in conjunction with the circulating and turbo soakback oil system to maintain engine combustion cylinder jacket temperature and lubricated engine components prewarmed and ready to quick start.

[.1.4.10]

<u>Major Instrumentation</u>

RED-AMBER-GREEN, ON-TRIPPED-OFF indication on the local engine control panel

<u>Control and Interlocks</u>

Energizes when jacket water temperature reaches 125°F decreasing and deenergizes at 155°F increasing.

The diesel engine immersion heaters are energized when the Div. I, II and III DG sets are in standby. Three position handswitches mounted on local engine control panel may be placed in either the HAND, OFF or AUTO position.

When the control switch in AUTO and the engine is not running, a locally mounted temperature switch will energize the heater to maintain jacket water temperature between 125°F and 155°F.

Division 1 & 2 Diesel Generators

When the control switch is in HAND, the temperature switch will control the immersion heater with the engine in standby or running.

Division 3 Diesel Generator

When the control switch is in HAND, the immersion heater will remain on continuously, regardless of temperature switch status.

Interim Summary:

Review Components Section:

- **Fuel Oil System**
- **Engine Starting Air System**
- **Combustion Air Intake**
- **Engine Exhaust System**
- **Lube Oil System**
- **Cooling Water System**

Request clarification on questions that may arise during review.

V. Interlocks

A. Automatic Starts [.1.7.1]

Each DG will start automatically on a LOOP or LOCA signal. The following are the auto signals:

1. Division I, II & III Auto Starts.

   a. Division I & II

      1) High Drywell Pressure (1.68 psig) and/or

      2) Low RPV Water Level 1 (-145.5")

      3) Bus Undervoltage

   b. Division III

      1) High Drywell Pressure (1.68 psig) and/or

      2) Low RPV Water Level 2 (-45.5")

      3) Bus Undervoltage

B. Diesel Generator Trips [.1.8.1]

1. The following conditions produce a DG trip:

   a. Engine Overspeed. Div 1,2 setpoint is 1035 rpm, Div 3 setpoint is 990 rpm. This condition will cause a local panel alarm. Possible causes would be loss of load to the DG or governor failure and Auto Actions are a trip of the DG. [.1.11.2]

   b. Engine Overcrank: Div 1,2 setpoint is <125 rpm >10 seconds after start. Div 3 setpoint is <150 rpm >20 seconds after start. This condition will alarm FAILURE TO START on local panels. Automatic actions is the lockout relays trip. Possible causes of trip could be low starting air, lockout relay not reset, overspeed not reset, engine maintenance switch in MAINTENANCE. [.1.11.3]

   c. Low Lube Oil Pressure: Div 1, 2 alarm setpoint is 26 psig and is indicated by LOW OIL LEVEL OR LOW OIL PRESSURE on local panels. Automatic actions are the DG will trip if oil pressure is <19 psig after >850 rpm for 50 seconds. Div 3 alarms LOW LUBE OIL [.1.11.4] [.1.6.2] [.1.10.6]

PRESSURE on local panel at 26 psig and Automatic actions are the DG will trip at 17.21 psig. These trips are bypassed on all 3 divisions if a LOCA has occurred. Possible causes are oil consumption, system leak, failure of engine driven pump, failure of main relief valve.	
d. High Water Jacket Temperature: Div 1,2 will alarm HIGH COOLANT TEMPERATURE OR LOW COOLANT LEVEL on local panel at 195°F and trip at 205°F. Div 3 will alarm HIGH WATER TEMPERATURE on local panel at 200°F and trip at 208 °F. Possible causes are loss of SX, failure of temp reg valve, excessive leakage from pump seal. These trips are bypassed on all divisions if a LOCA has occurred.	**[.1.11.5] [.1.10.6]**
e. Reverse Power: Div 1,2 will alarm REVERSE POWER on local panel and Div 3 will alarm ENGINE TRIP on local panel. Automatic actions for all 3 divisions is DG will trip. Possible causes are DG engine failure, governor failure, low excitation. These trips are bypassed if a LOCA has occurred.	**[.1.11.6] [.1.10.6]**
f. Loss of Excitation: Div 1,2 will alarm LOSS OF EXCITATION, Div 3 will alarm ENGINE TRIPPED on local panels. Automatic actions for all 3 divisions is DG will trip. Possible causes are voltage regulator failure. These trips are bypassed if a LOCA has occurred.	**[.1.11.7] [.1.10.6]**
g. Overcurrent: Div 1,2 will alarm OVERCURRENT and Div 3 will alarm ENGINE TRIPPED on local panels. Automatic for all 3 divisions are DG will trip. Possible causes are excessive load on bus, ground on bus. These trips are bypassed if a LOCA has occurred	**[.1.11.8] [.1.10.6]**
h. Generator Ground Fault (Div. I,II and III DGs) GENERATOR GROUND FAULT alarms on local panel and automatic actions are DG will trip. Possible cause is ground in DG.	**[.1.11.9]**
i. Differential Current (Div. I,II and III DGs) LOCKOUT RELAY TRIPPED will alarm on local panels and automatic action is a trip of the DG.	**[.1.11.10]**
For DIV. I & II (only); All of the safety trips are bypassed on a LOCA signal except engine overspeed, overcrank, and generator differential current. Div 3 DG will only trip on overspeed and generator differential current during a LOCA.	**[.1.8.2] [.1.10.6]**

For system component interlocks refer to components section.

Content/Skills	Activities/Notes
VI. Controls/Instrumentation/Power Supplies	
A. Electrical Power Supplies Div. I DG Support Systems:	
1. DG MCC 1A	
a. Diesel Generator Starting Air Compressors (1DG01CA(B)	**[.1.4.5]**
b. Diesel Generator Fuel Oil Transfer Pump (1DO01PA)	**[.1.4.6]**
c. Diesel Generator Circulating Oil Pumps (2)	**[.1.4.2]**
d. Diesel Generator Soakback Pumps (2)	**[.1.4.1]**
2. DC MCC 1A	
a. DC DG Circulating Oil Pump	**[.1.4.2]**
b. DC DG Soakback Pump	**[.1.4.1]**
B. Electrical Power Supplies Div. II DG Support Systems	
1. DG MCC 1B	
a. Diesel Generator Starting Air Compressors (1DG02CA(B)	**[.1.4.5]**
b. Diesel Generator Fuel Oil Transfer Pump (1DO01PB)	**[.1.4.6]**
c. Diesel Generator Circulating Oil Pumps (2)	**[.1.4.2]**
d. Diesel Generator Soakback Pumps (2)	**[.1.4.1]**
2. DC MCC 1B	
a. DC DG Circulating Oil Pump	**[.1.4.2]**
b. DC DG Soakback Pump	**[.1.4.1]**
C. Electrical Power Supplies Div. III DG Support Systems	
1. AB MCC 1C (1E22-S002)	
a. DG 1C Lube Oil & Turbo Soakback Pumps	**[.1.4.1] [.1.4.2]**
b. DG 1C Air Compressor (1E22-S001)	**[.1.4.5]**

Content/Skills	Activities/Notes
2. FB MCC 1A	
a. DG 1C Air Compressor (1DG03CA)	**[.1.4.5]**
3. AB MCC 1C1	
a. Diesel Gen. Fuel Oil Transfer Pump 1C (1DO01PC)	**[.1.4.6]**
4. Div. 3 DG CP/PT Cubicle 125VDC Inst. Bus C (1E22-S001C)	
a. DC DG Lube Oil Circulating. & Turbo Soakback Pumps	**[.1.4.1] [.1.4.2]**
For Controls and Instrumentation refer to the Components Section, Section IV.	

VII. Interrelationships

The following Systems support the Diesel Generator System

A. DC Electrical Distribution (DC)

The divisional Battery and DC Distribution Systems provide uninterruptable 125 VDC power for DG starting and control circuits. Divisional DC provides breaker control and tripping power for the DG output breakers. It also provides power to the DC priming, circulating oil and turbo soakback oil pumps. **[.1.12.2]**

B. Shutdown Service water (SX)

Each division of the Shutdown Service Water (SX) System supplies cooling water to the jacket water heat exchanger for its associated divisional DG. The Shutdown Service Water prevents the engines from overheating during operation. **[.1.12.1]**

C. AC Electrical Distribution (AP)

The 480 VAC Distribution MCC's provide power to the following Diesel Generator System components: **[.1.12.3] [.1.13.1]**

1. AC Motor Driven Air Compressors
2. Fuel Oil Transfer Pumps
3. Immersion Heaters
4. Generator Space Heaters
5. AC Circulating Oil and Soakback Pumps

AC control power for the various operating switches and indicating lights for the above components is provided from 480/120 VAC potential transformers

D. Diesel Generator Ventilation (VD)

Diesel Generator Ventilation provides ventilation and cooling for the associated diesel, fuel oil day tank, and fuel oil storage tank rooms. **[.1.12.4]**

VIII. Technical Specifications

A. Safety Limits & Limiting Conditions for Operation (LCOs) **[.1.14] [.1.13]**

3.3.8.1 Loss of Power (LOP) Instrumentation

3.3.5.1 ECCS Instrumentation

3.8.1 AC Sources-Operating

3.8.2 AC Sources-Shutdown

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

IX. Operational Characteristics

A. Diesel Engine Start

(Optional) Student Exercise:
Refer to Figure 13, DG Start Control Logic for the following logic discussion.

Div. I, II and III DG's may be started manually from the Main Control Room or locally. Each DG will start automatically on a LOOP or LOCA signal. The LOCA Signal for Div. I & II DG's is a high Drywell Pressure and/or Low RPV Level 1. The LOCA signal for Div. III DG is a high Drywell Pressure and/or Low RPV Level 2. The LOOP signal for Div I, II & III DG's comes from two different under voltage schemes: loss of voltage and degraded voltage. Loss of voltage actuates off first level undervoltage relays. Degraded voltage actuates off second level undervoltage relays.

[.1.7.1]
(Figure 13)

The Div. I & II loss of voltage scheme has two bus under voltage relays on 4.16 kV emergency bus 1A1 and 1B1, and two infeed undervoltage relays on the RAT and ERAT 4.16 kV infeeds to each 4.16 kV emergency bus 1A1 and 1B1. The loss of power relays actuate at 69% of 4.16 kV, and are connected in a two-out-of-two taken three times logic plus a short time delay. This means that both undervoltage relays on bus 1A1 or 1B1 and both undervoltage relays on each associated 4.16 kV infeed to that bus must sense undervoltage for a short time delay to start the associated Div. I & II DG on loss of power.

The Div. III loss of voltage scheme uses four first level (60% of 4.16 kV) undervoltage relays connected in a one-out-of two taken twice logic. The Div. III loss of voltage logic output is controlled by a time delay relay.

The degraded voltage functions for Div. I, II and III use two second level (98% of 4.16 kV) undervoltage relays on each 4.16 kV emergency bus connected in a two-out-of-two logic. If both degraded voltage relays on a vital 4.16 kV bus sense a degraded voltage condition, and the degraded voltage condition persists for 15 seconds, then the ERAT or RAT infeeds to the vital 4.16 kV bus will trip and the associated divisional diesel will start and connect to the bus.

The LOOP and/or LOCA signals initiate the starting sequence for the Div. I and II DGs provided the safety shutdown circuits are reset and the engine maintenance switch is in OPERATE. When switch HS-502 at the Remote Shutdown Panel is positioned to EMERGENCY, Diesel Generator 1A starting under LOCA is prevented. Diesel Generator 1A will only start and connect to the 1A1 bus on a bus undervoltage.

1. Division I & II

   Figure 16

   [.1.7.1]

   Starting control current passes through normally closed 86 lockout relay and control setup relay contacts, and energizes the (K19) operate coil. This causes the (K19) operate coil contacts to close and, via series connected relays, causes the DC fuel priming pump motor to energize, thereby assuring an adequate supply of fuel during engine cranking. Energizing the (K19) operate coil deenergizes the engine jacket water immersion and the generator space heaters. It also energizes a relay that causes the air start solenoid valves to open. This provides starting air pressure to the diaphragm of the main air start valves causing them to open. Starting air pressure is applied to the air start motors. The air start motor pinion gears engage the engine flywheel ring gear. When the air start motors begin to turn they turn the crankshaft and crank the engines.

   During the engine starting sequence, any of the following conditions will terminate the engine cranking:

   a. Engine Cooling Water Pressure > 20 psig

      [.1.16.1]

      When cooling water pressure reaches 20 psig, a switch will open causing the air start solenoid valves to be de-energized. This causes the solenoid valve to vent to atmosphere and results in closure of the air-operated, air start valves and, ultimately, the isolation of starting air to the air start motors.

   b. Engine Speed > 125 RPM

When engine speed exceeds 125 RPM a switch will open a set of contacts in the starting circuitry that, through a series of relays and contacts, will de-energize the air start solenoids as described above, causing termination of engine cranking. [.1.16.2]

c. Generator Voltage at (approx.) 80% of Rated Level [.1.16.3]

When generator voltage reaches approximately 80%, normally closed contacts, located in series with the speed switch contacts open. This terminates engine cranking in the same manner described above.

After the engine starts and begins its acceleration to rated speed, a set of speed switch contacts will close at 850 RPM and energize two relays. One of the relays will deenergize the fuel priming pump motors and illuminate the engine running indicator lights on the local and MCR control panels. After a 50 second time delay the other relay will close a set of contacts that completes the power circuit to the arm and shutdown switches.

If the engine has not started after 10 seconds of cranking, a time delay relay will energize causing a set of contacts to open. The open contacts deenergize a relay which deenergizes the air start solenoids and terminates engine cranking.

2. Division III

The starting circuitry for the Div. III Diesel Generator is somewhat different than that of the Div. I and II diesels. [.1.7.1] Div. III DG may be started automatically, or manually from the local and MCR panels. Following initiation of a start signal, the starting sequence for the Div. III DG progresses as follows:

The start signal energizes the pilot relay. The pilot energizes the indicating unit cranking, crank jog delay, and the 20 second overcrank time delay relays.

When the crank jog delay relay energizes, there is a 0.75 second delay before the overcrank time delay relay is energized. This allows the air start solenoids to energize, open the associated valves and provide starting air to the air start motor pinion gears. When the pinion gears successfully engage on either pair of main air start motors, an air pathway to the diaphragm of the air-operated, main air start valves is established. This causes the main air start valve to open and supply starting air to the air start motors.

The release of main starting air also causes the air pressure cranking jog switch to open preventing de-energization of the cranking circuit. If the teeth of the pinion gear do not successfully mesh with the flywheel the air start valves will not open. The crank jog time delay relay will time out and deenergize a relay (K16) which in turn deenergizes the air start solenoid valves and the crank jog delay relay.

When the crank jog delay relay deenergizes, the K16 relay is reenergized. This reenergizes the crank jog delay relay and the air start solenoids which causes the air start motor pinion gears to be bumped with air until the gear teeth mesh with the flywheel. This cycle continues until the air motor pinion gears successfully engage the flywheel ring gear and engine cranking commences.

The pilot relay from the initiating start signal will also start the fuel priming pump. If the AC motor driven lube oil pumps are not operating, the DC motor driven pumps will start automatically.

As the cranking sequence progresses, the engine accelerates. As the engine reaches 150 RPM the air start solenoids deenergize. This isolates main starting air. The 50 sec time delayed, safety setup relay is also energized. The 50 sec delay allows time for water pressure to build so the low water pressure alarm does not annunciate. It also allows the low oil pressure relay to seal in as oil pressure increases to 16 psig.

[.1.6.2] [.1.16.4]

As engine speed passes through 870 RPM, the speed sensing relay is energized. This allows the Div. III Diesel Generator circuit breaker controls to energize if the Div. III output breaker is racked in.

[.1.16.5]

B. Diesel Engine Stop Circuitry

.1.8.4

Student Exercise: Refer to Figure 18, DG Stop Control Logic, for the following discussion.

The Div. I and II DG normal stop circuits provide a means of halting the diesel generator without tripping any of the protective shutdown circuits or the 86 Lockout relay. The diesel may be shut down from the local or Main Control Room panels.

(Figure 17)

The DG output circuit breaker is opened and the engine should be allowed to complete the required cooldown prior to stopping the diesel engine. In a normal stop sequence the MCR or Local places the control switch to the Stop position. This energizes the reset coil of the K19 operate relay. The associated relay contacts reset, causing the engine governor dump solenoid to energize This causes the governor's hydraulic oil pressure to drain the from the governor's power piston, causing the fuel injector racks to move to the no-fuel position: Thus, starving the engine of fuel and stops the DG. This is NOT a Lockout (86-relay does not trip on normal engine S/D).

The Emergency Stop circuits for the Div. I and II Diesel Generators are equipped with both local and MCR emergency stop pushbuttons. Depressing either pushbutton will trip the 86 lockout relay, This causes the governor dump solenoid to energize and drain the hydraulic oil pressure from the governor's power piston, causing the fuel injector racks to move to the no-fuel position: Thus, starving the engine of fuel. Additionally, tripping the 86-lockout relay will cause the Generator field and Output breakers to open (41 relay lockout). Use of the emergency stop pushbutton requires 'Local manual reset' of the Lockout trips (86 and 41 Lockouts).

The shutdown circuitry for the Div. III Diesel Generator is similar to that of the Div. I and II. Placing the control switch to Stop will de-energize the pilot and pilot auxiliary relays. This energizes a solenoid which drains the oil from beneath the governor power piston. The governor power piston strokes downward, forcing the fuel injector rack to the no fuel position. This starves the engine of fuel and stops the engine. (No Lockout relay actuates)

The shutdown solenoid is maintained energized for 50 seconds to prevent a manual restart and loading of the Div III diesel generator during coastdown following a shutdown signal. The time delay begins when the shutdown signal is removed (i.e., DG control switch released, local stop pushbutton released, or generator lockout relay reset) and must time out before a normal start sequence will occur. This feature is unique to the Div. III diesel generator; Div I and II have electronic governors. During the performance of surveillance procedure CPS No. 9080.14 in early 1999, the operators were unable to restart the diesel during the hot restart portion of the surveillance. The operation of this time delay was not understood by the operating crews and the surveillance procedure did not warn that this time delay would activate in this situation. (Note: The 50-second timer also inhibits voltage control). The surveillance was subsequently revised to insert an explanatory note in the appropriate portion of the hot restart procedure. See Condition Report 1-99-02-017 for further details.

The Div. III Diesel Generator, like the Div. I and II DGs, is equipped with local and MCR Emergency Stop pushbuttons. Depressing either button will trip the (K15) lockout relay and halt engine operation. Actuation of the Emergency Stop circuit requires manual resetting of the Lockout trips.

C. DG Parallel Operation with the GRID

[.1.4.11]

The engine speed and voltage droop characteristic allows paralleling/synchronizing/load sharing between the DG and the GRID. The speed droop characteristic causes the DG to attempt to slow down as increasing load is applied to the generator. Therefore, to transfer real load (kW) onto a DG in parallel with the GRID, the speed of the DG is increased using the engine governor speed controls. To remove load from a DG in parallel with the GRID the speed of the DG is lowered using the engine governor speed controls. The effect is to transfer the electrical load from one AC machine to another. The actual speed of the AC machines in parallel does not change because the DG is electrically locked in sync with the GRID. If a DG was supplying an isolated 4.16 kV bus, and the engine governor speed controls was similarly raised or lowered, then the actual engine speed would raise and lower because the GRID would not be there to hold the DG in sync. This would raise and lower the DG and isolated bus frequency.

(Figure 18).

The voltage droop characteristic reduces the voltage regulator setting as reactive load is raised and raises the voltage regulator setting if reactive load is reduced. When the operator goes to "raise' on the voltage regulator, reactive load will increase until the voltage droop returns the regulator setting to actual buss voltage. When the DG is not paralleled to the grid, the voltage droop is set to zero which effectively removes it from operation.

In an emergency the DG is not synchronized with the GRID. The DIV 1 and 2 DG's start in response to the LOCA Level 1 signal (RPV level 1/High D/W Pressure), and LOOP signal (associated DG bus UV). DIV 3 DG start in response to the LOCA Level 2 signal (RPV level 2/High D/W Pressure) and LOOP signal (associated DG bus UV). When the DG output voltage and frequency is sufficient (>80% of rated) the DG output breaker will close if the associated bus infeed breakers are open and a bus undervoltage condition is present. If no bus undervoltage condition exists, then the DG will run unloaded and the DG output breaker will remain open. **[.1.10.6]**

If the DG is running in parallel with the GRID and a LOCA signal is received, then the DG output breaker will trip open. The DG will continue to run unloaded. If a low vital bus voltage occurs at this time, then the DG output breaker will close and the DG will supply power to the vital bus.

Non-emergency synchronizing of a DG with the GRID occurs during surveillance and post maintenance testing. DG's are not synchronized with the GRID to enhance unit capability for load peaking, or as a protective measure during severe weather conditions. Industry experience has shown this to be deleterious to vital bus continuity of power.

The amount of oil added to the DG oil pan sumps is recorded in CPS 3506.01F001 to track the engines lube oil consumption.

Chemistry department must sample fuel oil shipments prior to adding oil to any DG fuel oil storage tank.

The idle speed start feature is only present on Div. I & II DG's. The idle speed start feature allows the operator to start the DG and perform a controlled warmup of the diesel engines at 400 RPM. This produces less stress on engine components during engine starts, and consequently improves overall DG performance and reliability.

When performing DG testing, maintain DG frequency as close to 60 Hz as practical to limit fuel consumption.

D. SYSTEM IMPACT/CONSEQUENCES **[.1.9.b]**

1. Turning off the SYNC SCOPE when operating a Diesel Generator in parallel with the Grid

[.1.10.1]

The DG sync scope switches are directly in line with the DG output breaker trip coil. If the DG output breaker is closed, and the sync switch is turned off, the DG output breaker will trip.

2. Extensive Operation of a Diesel Generator at Low Load

The DG should be loaded to >75% of full load whenever possible. DG operation under light load should be minimized to reduce turbocharger gear train wear and to prevent the buildup of lube oil in the DG exhaust system (called "wet stacking"; when this oil mixes with carbon buildup typically found in diesel engine exhaust stacks, the result is referred to as "souping").

[.1.10.2] [.1.15.2]

At low loads (<20%), lube oil can leak past piston rings and build up in the exhaust. To clean out the exhaust stacks, the DG should be loaded to a minimum of 40% for at least 30 minutes prior to shut down after operation at synchronous speed at loads 20% or less for at least 4 hours, or operation at idle speed (~400 rpm) for 8 hours or more.

3. Stopping a Diesel Generator with the E-STOP pushbutton

The DG should not normally be stopped by using the emergency stop pushbutton. Depressing the E-STOP pushbutton trips <u>both</u> the exciter field (41) and DG lockout (86) relays. These relays require a local reset to return the DG to standby. Holding the Engine/Generator Lockout in reset for greater than 2 seconds will damage the lockout relay.

[.1.10.3] [1.15.3]

4. Running vs. stopping a DG after restoring from a loss of Jacket Water Cooling

Shutting down a hot DG during a loss of jacket water cooling or a loss of SX cooling can result in overheating of the engine valves and combustion cylinders. It is preferable to unload the DG, and rapidly refill jacket water, or slowly reestablish SX cooling flow without shutting down the engine. This allows controlled cooldown of the engine and may avoid damage to the combustion cylinders resulting from overheating if the DG were suddenly stopped.

[.1.10.4] [.1.15.4]

5. Loss of DG Ventilation Supply Fan

The VD system fans control the temperature in the DG rooms. The VD fans also provide sufficient air flow to purge the fuel oil day tank and fuel oil storage tank rooms of combustible fumes. Operability of the VD system is a prerequisite for DG system operation. DG temperatures and operation must be closely monitored if the VD fan is unavailable and emergency DG operation is required.

[.1.10.5] [.1.15.5]

6. DG Load Sequencing

The vital bus loads have delay timers which allow controlled starting of large ECCS pumps and related support loads following a LOCA or LOOP. This "sequencing" ensures starting and power availability for loads required for safe shutdown of the plant.

[.1.8.3]

Following a LOOP event, the diesel generators will start and accelerate to rated speed. Div. I, II and III generator output breakers will close and supply power to the Class 1E, 4.16 kV busses: 1A1, 1B1 and 1C1 busses when each unit's generator output voltage and frequency is within the proper range. This should occur within 12 seconds of DG start signal.

Prior to DG output breaker closure, all 4.16 kV motor loads are shed from the 1A1 and 1B1 busses. After the associated Div. I and II DG breakers are closed the loads are sequentially connected to the respective bus. Individual time delay relays are used to accomplish the sequential loading of busses 1A1 and 1B1. In addition, other loads may be connected manually by the operator as needed.

The 1C1 bus motor loads are not shed following a LOOP. Bus 1C1 loads remain connected and reenergize immediately when the Div. III DG output breaker closes. All of the bus 1C1 loads are associated with the High Pressure Core Spray (HPCS) System. The largest single load on bus 1C1 is the HPCS pump motor. The Div. III (DG 1C) Diesel Generator is sometimes referred to as the "HPCS Diesel Generator."

The DG output breaker will not close if normal AC power is present when the Div. I, II or III DG Set reaches rated frequency and voltage. In this case the DG will remain at rated frequency and voltage until manually shut down. If a LOOP occurs and a LOCA signal is not present, then only loads necessary for safe shutdown of the plant are connected. If a LOCA signal is received while operating unloaded, then all non-essential loads will be shed and the required Class 1E loads will be automatically connected to the bus as the individual delay timers time out.

RHR A, B starts after 5-second timer.

RHR C and LPCS start immediately.

Div 1, 2 SX pumps start after a 10-second timer.

Div 3 loads (HPCS, SX) start immediately.

7. Closing DG output breaker with DG secured	
CPS operating experience includes two instances where vital bus DG's were motored by inadvertently closing the DG output breaker with the DG at rest. Reverse powering, or motoring a DG results in inadequate lubrication, and inordinate stress on the DG components.	
8. Effect of LOCA/LOOP on Idle Speed operation	
If a LOCA or LOOP occurs while the DG is running at idle speed, the engine will automatically accelerate to 900 rpm. The RUN/IDLE switch shall be restored to the RUN position as soon as possible following the LOCA or LOOP initiation signal.	**[.1.10.14]**
9. Effect of Placing the DG Engine Control Switch in Lockout/Maintenance	
The DG engine control switch on the local control panel is used during engine barring and prestart checks to prevent the DG from inadvertently starting. The MCR must be notified when DG control Switch is placed in LOCKOUT (Div I & II) or MAINTENANCE (Div III) because this makes the DG INOPERABLE.	**[.1.10.13**
10. Operating a Diesel Generator with Personnel in the DG HVAC Room	
Prior to running a Diesel Engine, ensure that all personnel have exited the Diesel Generator HVAC Room. When a diesel is running, it creates a large differential pressure across the HVAC room door, making it nearly impossible to open the door.	**[.1.10.10] [.1.15.10]**
11. Not Holding the Manual Feed Prime Pushbutton for One Minute	
When priming the Diesel Engine using the Manual Feed Prime pushbutton, the button must be held depressed for a minimum of one minute to ensure that the injectors are completely filled. Failure to hold the pushbutton for this length of time may result in a failure of the Diesel Generator to start. Fuel priming is not permitted immediately prior to a quick start or integrated surveillance test run.	**[.1.10.11] [.1.15.11]**

12. Circuits 13(14) and 32 NOT energized on their associated DC MCC for Div. 1A(1B)

    [.1.10.12] [.1.15.12]

    a. Opening circuit # 13 on DC MCC 1A for the Div. 1 DG Control Panel will prevent starting of the 1A DG.

    b. Opening circuit #14 on DC MCC 1B for the Div. 2 DG Control Panel will prevent starting of the 1B DG.

    c. Opening circuit #32 for the Div. 1 (Div. 2) RHR logic will prevent starting of the Div. 1 (Div. 2) ECCS when the bus is reenergized.

X. Operating Experience (OPEX)

[.1.9.a]

A. SOER 83-1, Diesel Generator Failures

Operability of emergency diesel generators is important for plant safe shutdown following a loss of off-site power. Considerable effort has been spent in monitoring, repairing, and testing diesel generators. The failure frequency remains high indicating additional attention is needed.

Failures of emergency diesel generators and associated support systems are frequently reported under both test and operating conditions. Inoperability of these back-up power sources significantly increases the risk of plant damage should a loss of off-site power occur.

Engine bearing damage due to inadequate prelubrication at Hatch and start failures due to a worn cylinder and dirt in the air start system at Dresden are two examples of over 450 Licensee Event Reports (LERs) associated with diesel generators submitted since January 1980. These LERs report a wide variety of problems discovered during testing and operation that have rendered diesel generator units inoperable.

Forty (40) percent of failures are associated with failed or degraded mechanical components. Forty-two (42) percent of failures are associated with failed or degraded electrical or C&I components. Eighteen (18) percent of failures are associated with personnel errors.

Improvement is needed most in the area of preventive maintenance. Evidence suggests that many failed parts and components may be detected or prevented by a comprehensive preventive maintenance program. Increased emphasis is being placed on regular inspection, adjustment, and cleaning with replacement of parts prior to end-of-life failure.

LER data indicates that personnel errors are primarily associated with mispositioned valves, switches, or breakers; incorrect adjustment of controls; or incorrect operating practices. In many cases, these errors are the result of insufficient operator familiarity with the equipment, operating procedures that do not include detailed instructions for each required action, and failure to follow procedures.

DG Testing contributes significantly to engine component failure. Engine failures are largely due to inadequate prelubrication and cold start testing followed by immediate and rapid loading to rated capacity, short duration runs, or extended operation with no load. These practices are contrary to the manufacturers recommendations. Due to the significance of this problem manufacturers have developed "backfittable" continuous lubrication systems. This continuously lubricates engine bearings and should reduce engine failure.

The CPS divisional DGs were backfitted with Turbo Soakback & Circulating Oil systems to reduce cold start stress. The divisional DG Idle Start modification in conjunction with reduced cold start/rapid loading significantly reduces testing related DG wear.

B. OE 7264, Bearing Failure and Motorizing of the Division III Diesel Generator

Division III DG inboard bearing failed during the performance of the 24-hour surveillance run. This resulted in damage to the generator rotor shaft. The bearing failure occurred after running Div. III DG at full load for 19 hours, and was attributed to maintaining an inadequate bearing oil level and a chronic bearing oil leak.

Inadequate oil level for the DG generator bearing resulted from a misunderstanding of what the indication marks on the sightglass meant. The higher mark indicated the minimum prestart oil level, and the lower mark indicated the minimum operating oil level. The operator incorrectly assumed these marks indicated high and low oil level, and that oil level between the two marks was desirable. Oil level markings consistent with DG operation were determined and applied.

The 4.16 kV DG output breaker was inadvertently closed while racking the breaker out to the disconnected position. This motorized the Div. III DG. Generator megger, polarization index, and winding balance test results were satisfactory. An additional boroscope investigation of the Div. III generator revealed no abnormalities.

C. CPS LER 96-011, Priming of Emergency Diesel Generators during performance of certain Surveillance Tests determined to be Preconditioning

During an Operational Safety Team Inspection (OSTI) a concern was raised about the practice of priming the Emergency Diesel Generator (EDG) fuel systems. Manually priming the engines with the Fuel Oil Priming Pumps and by excessive prestart engine barring prior to the 184 day "Quick Start" or EDG/ECCS Integrated surveillance's has the potential to mask degraded engine starting capability. Undesired engine priming, or "preconditioning" can invalidate EDG surveillance testing and potentially masks EDG degradation which would otherwise be discovered during the 184 day "Quick Start" or the 18 month EDG/ECCS Integrated surveillance's.

The procedures for the monthly EDG operability surveillance and the 184 day EDG "Quick Start" were combined in October 1994 following the Div. I and II Idle Start modifications. The prerequisite to prime Div. I & II diesels prior to engine starting was carried over into the new surveillance revision without differentiating between engine quick starts and idle starts. This aspect was overlooked during the evaluation of the procedure change. After this was discovered All three divisional EDGs were satisfactorily start tested without manual priming. This coupled with an evaluation of engine preventive maintenance records proved that degraded engine start capability was not masked while engine priming was generally employed.

Specific procedural guidance limiting the amount of prestart engine barring was not provided in the 'quick start" or Integrated surveillance tests. This was considered another potential source of "preconditioning". Manual prestart engine barring of one to two revolutions is not sufficient to prime the EDG fuel oil system. Prestart engine barring is necessary to prevent engine damage.

D. CPS CR 1-98-02-265-0, POTENTIAL VIOLATION FOR FAILURE TO FOLLOW CONDUCT OF OPERATIONS PROCEDURE

Potential Violation for a failure to follow CPS No. 1401.01, Conduct of Operations, step 8.5.4.2. Step 8.5.4.2 requires that indications are provided to monitor plant parameters and shall be believed, unless verified faulty by two alternate independent means when possible, or through maintenance trouble shooting. During the Division II Diesel Generator run on 2/11/98 operations identified that the local kW meter was reading 4500 kW which indicated that the DG was operating outside its normal power band. The MCR kW meter was reading within the operating band for the DG and therefore the local indication was disregarded which is a violation of CPS 1401.01 step 8.5.4.2.

E. CPS CR 1-98-02-298-0, PERFORMANCE OF 9080.13 COULD OVERLOAD EDG

During investigation for CR 1-98-02-215 it was identified that CPS 9080.13 directs the EDG to be operated at 4400 to 4500 kW for two hours. Per the vendor, the maximum loading allowed on the EDG is 4290 kW for 30 minutes. CPS 9080.13 was last performed on Division 1 on 11/7/96 and Division 2 on 12/7/96. CPS 9080.13 for Div 1 and 2 DGs was revised to a lower required 2-hour loading band of ≥ 105% (4100-4200 KW). CPS 9080.14 for Div 3 DGs was revised to a lower required 2-hour loading band of 105-100% (2320-2420 KW). The DGs were evaluated satisfactory for no damage caused by this overloaded operation.

F. DIV III Speed Droop setting gives unexpected response.

During a monthly surveillance of the Division 3 Emergency Diesel Generator (EDG) under CPS 9080.02, the EDG speed decreased when speed droop on the mechanical Woodward UG-8 governor was returned to zero after the EDG was unloaded and operating at rated speed. The expected response was for speed to increase when speed droop was dialed down. This event occurred while operators were preparing to shutdown the EDG to restore the standby readiness of the EDG. The steps for setting speed droop were being performed as directed by CPS 9080.02. The concern raised is that the setscrew on the speed droop cam may be loose causing a slightly negative speed droop when zeroed. As an immediate action, an inspection was completed in late November 2001.

The response of the Division 3 EDG to speed droop changes was found to be correct. The original equipment manufacturer (OEM) of the EDG, Engine System Inc. (ESI) confirmed that when the EDG is not paralleled to the grid and under no load, EDG speed could decrease slightly as speed droop is dialed down. The following is the EDG System Manager's telephone communication with ESI on the effects speed droop setting on EDG response:

Engine Systems Inc (ESI) was contacted to discuss the expected response of the UG8 governor to dialing droop in or out when the Diesel Generator (DG) is not paralleled. This question arose recently when, during a surveillance test of the Division 3 DG, operators noticed speed drop after taking the droop knob from 5 to 0. The expected response was for speed to increase.

ESI indicated that lowering droop while the DG is not paralleled and at "no-load" can cause a slight decrease in engine speed consistent with the response observed on the Division 3 DG. This occurs because lowering droop will raise the sliding fulcrum and allows the speeder spring to relax, which will cause the flyweights to mover outward. The outward movement of the flyweights raises the pilot valve plunger to reduce pressure to the underside of the power piston resulting in a decrease in speed. ESI also indicated that the effect of changing droop while the DG is powering an isolated load is dependent on the output shaft position (load) and the droop dial position. When the DG is under load and droop is lowered, the sliding fulcrum will move in an upward arc but can have a net downward movement on the droop lever. This is possible because the lever is at an angle relative to the sliding fulcrum when the DG is loaded. Under light loading, the droop lever angle is small and the lever will move in the same direction as the sliding fulcrum. Under heavier loading, the droop lever angle approaches 30 degrees causing a net movement downward as the sliding fulcrum moves up. Therefore, engine speed can increase or decrease as droop is lowered depending on the amount of engine load and speed droop. Although the effects of changing droop under various loading conditions can vary, ESI indicated that the important factors in determining the acceptability of the droop adjustment is: (1) loading is stable when the droop is set and the DG is paralleled to the grid and (2) generator frequency remains approximately constant when droop is off and the DG is loaded on an isolated bus. At CPS, both such factors are periodically tested and the results have been satisfactory.

Therefore the observed response of the Division 3 DG to changing droop is acceptable and is consistent with the expected operation of the UG8 governor."

The response of the Division 3 EDG to changing speed droop on the UG-8 governor was confirmed to be consistent with the response of similar EDG sets at LaSalle, Quad Cities, and Dresden stations. The System Managers at those sites stated that lowering speed droop setting on their EDG sets with UG-8 governors resulted in a slight drop in engine speed.

G. Emergency Diesel Generator Turbocharger Fire

While operating the Division 1 emergency diesel generator (EDG) for monthly surveillance testing, an operator noticed a small fire in the vicinity of the turbocharger. The EDG was immediately (manually) unloaded and secured. The fire was reported to be out in less than one minute of the initial report. The affected EDG had been at full load for approximately 35 minutes at the time of the event. No personnel were injured as a result of this event. Offsite fire department assistance was not requested. The diesel had been declared inoperable and the station entered the applicable technical specification LCO. The back-up EDG was available.

Conclusion/Lesson Summary

The Diesel Generator System provides an independent, onsite source of emergency 4160 VAC, 60Hz power to the Division I, II and III Class 1E busses.

The DG's automatically start in response to a LOCA or a LOOP signal.

Minimum onsite capacity of the Diesel Generator Fuel Oil Storage and Transfer System shall be sufficient to operate each diesel generator for 7 days while supplying maximum post-LOCA load demand.

The Fuel Oil Day Tank stores sufficient diesel fuel oil to operate the Division I, II and III DG's for a minimum of 1 hour at maximum post LOCA electrical loading. Each day tank has an overflow line that drains back to the associated fuel oil storage tank. When the fuel oil transfer pump is operating the day tanks overflow to the fuel oil storage tank.

The Starting Systems for each DG set can start its engine(s) five times in succession without recharging the air receivers. The Air Start System will start the engine so that the DG is operating at rated speed, voltage and frequency within 12 seconds following receipt of the start signal.

Each starting air receiver provides enough air to accelerate the associated diesel engine to starting speed (approximately 150 RPM) five times in succession without recharging the receiver.

Each DG is equipped with the following independent auxiliary systems:

- Fuel Oil Storage and Transfer
- Combustion Air and Exhaust
- Starting Air
- Lube Oil
- Cooling Water
- Fuel Oil

Differences between Div. I & II and Div. III DG's:

- Div I & II are tandem engines. Each DG has one 12 and one 16 cylinder engine connected to a common generator. Div. III only has one 16 cylinder engine. All engines are two-stroke turbocharged engines.

- Div I & II have EGB-13P governors. They are electrically controlled with a mechanical backup. Div. III DG has a UG-8 mechanical governor.

- Div I & II carry loads which are automatically load shed during LOCA/LOOP conditions, and are sequenced back on so that sufficient power is available to start the safe shutdown loads. Div. III almost exclusively powers the HPCS pump motor. The Div. III loads do not load shed or sequence back on during a LOCA or LOOP. when power is restored to 4.16 kV bus 1C1 the Div. III loads will energize/start immediately.

- Div III air start motors must both engage to start the DG. Div I & II starters do not have to engage the ring gear to allow starting air to the air start motors.

- All DG's can be controlled from the local engine control panel. Only Div. III can be synchronized from the local engine control panel.

The following conditions produce DG trips:

- Engine Overspeed

- Engine Overcrank (considered a failure to start, but does cause the lockout relay to trip)

- Low Oil Pressure

- High Jacket Water Temperature

- Reverse Power

- Loss of Excitation

- Overcurrent

- Generator Ground Fault

- Differential Current

All of the safety circuits operate by actuating a relay or relays that, in turn trip an 86 lockout relay. This causes the engine governor to drive the fuel injector rack to the no-fuel position, starving the engine of fuel and causing it to stop. Tripping the 86 lockout relay will cause the generator field and output breakers to open. For Div 1 & 2 DG's - All of the safety trips are bypassed on a LOCA signal except the engine overspeed, overcrank, and generator differential current trips. Div 3 DG will only trip on overspeed and generator differential current during a LOCA.

Kathon FP1.5 Biocide is classified as a hazardous material. It is a SEVERE IRRITANT. Personal protective equipment for handling Biocide include: eye goggles or a face shield, butyl rubber or nitrile gloves, and a chemically treated apron.

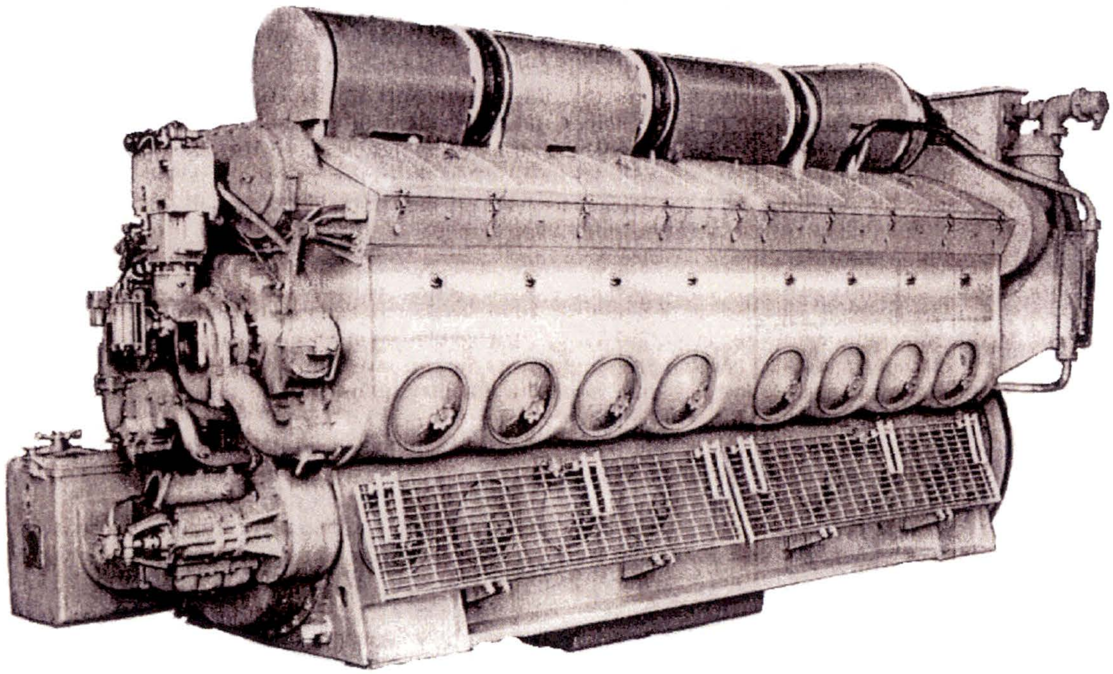
List of Attachments

Figures

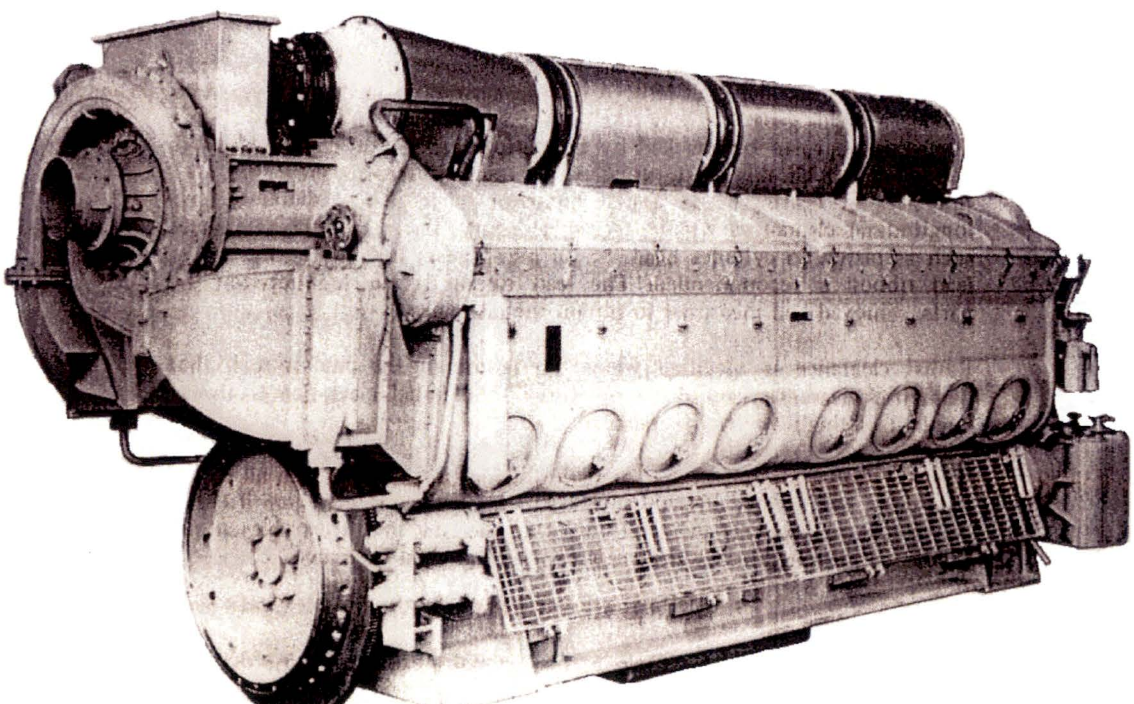
Figure #	Description	Rev Date
1	Turbocharged Diesel Engine	
2	Series 645 Diesel Engine	
3	Accessory Drive Gear Train	
4	Camshaft Drive Gear Train	
5	Turbocharger Assembly	
6	Cylinder Air Intake & Exhaust	
7	Lubricating Oil Internal Piping Arrangement	
8	Lubricating Oil Piping Arrangement	
9	Cooling Water & Oil System Interface	
10	Fuel Oil Header - Injector Arrangement	
11	Lube Oil Strainer	
12	Lube Oil Strainer Internal Valve Arrangement	
13	DG Start Control Logic	
14	DG Stop Control Logic	
15	DG Speed Control Logic	
16	DG Fuel Oil Storage & Transfer System	
17	Engine Fuel Oil System	
18	Div. I & II Starting Air System	
19	Div. III Starting Air System	
20	Lube Oil System	
21	Engine Jacket Water Cooling System	
22	Div I, II Electrical Speed Control	
23	Div III Governor	
24	Div I DG Governor (New Model)	01/10/07
25	Keinie Valve	01/10/07
26	Keinie Valve with operator	01/10/07

ATTACHMENT 1: Tech Spec Exercises

Figure 1
Turbocharged Diesel Engine



ACCESSORY END



TURBOCHARGER END

Figure 2
Series 645 Diesel Engine

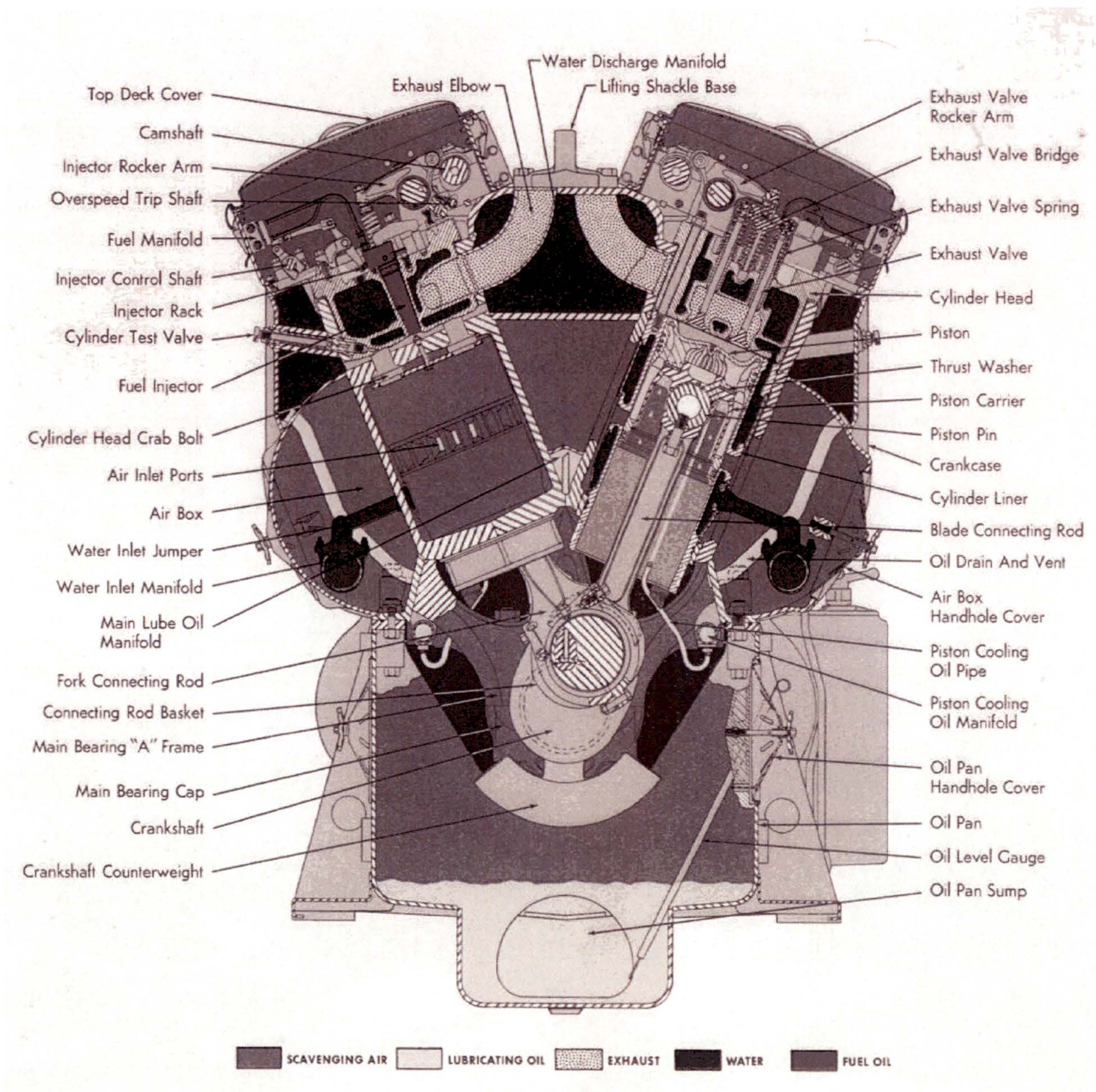


Figure 3
Accessory Drive Gear Train

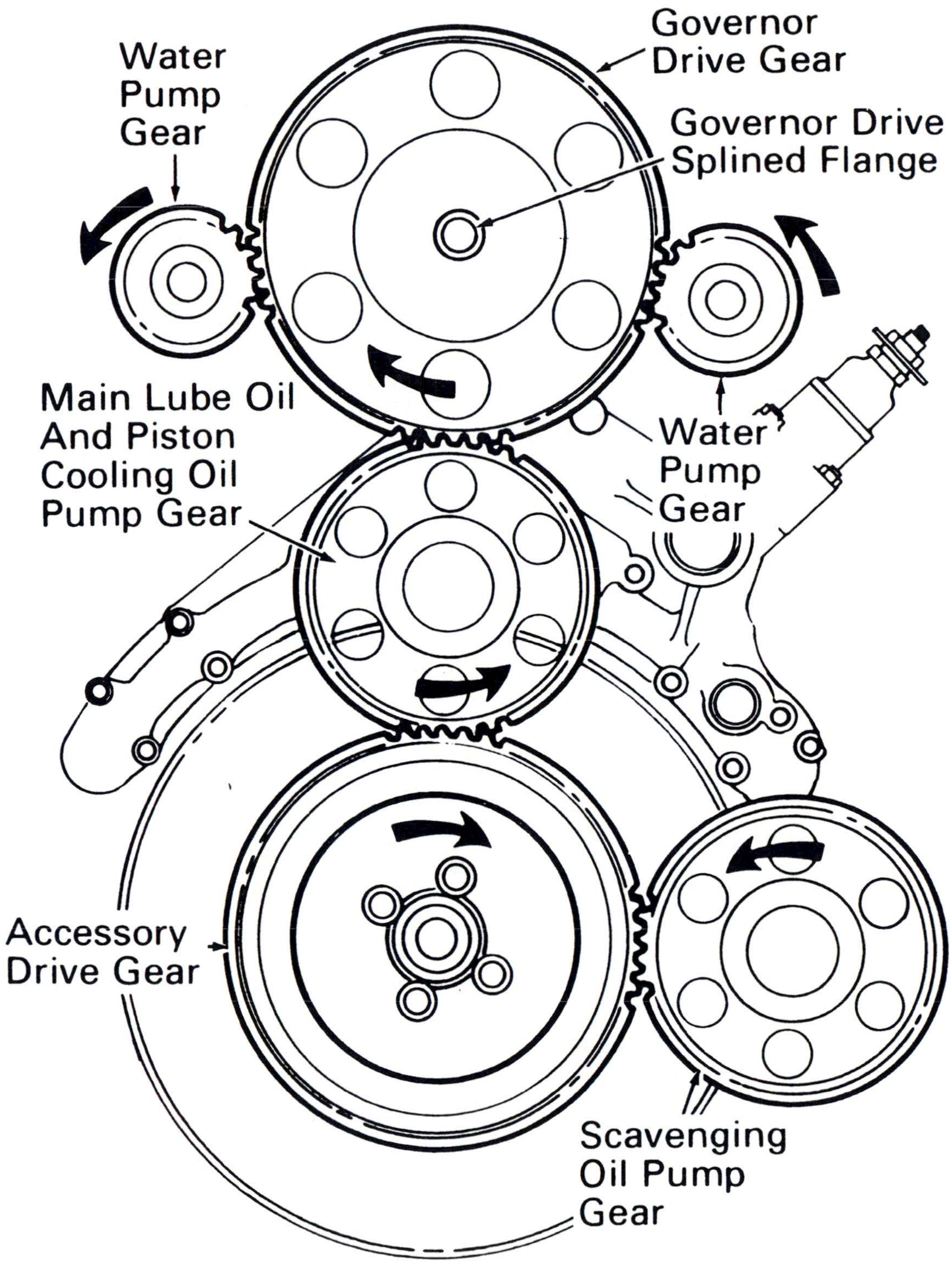


Figure 4
Cam Drive Gear Train

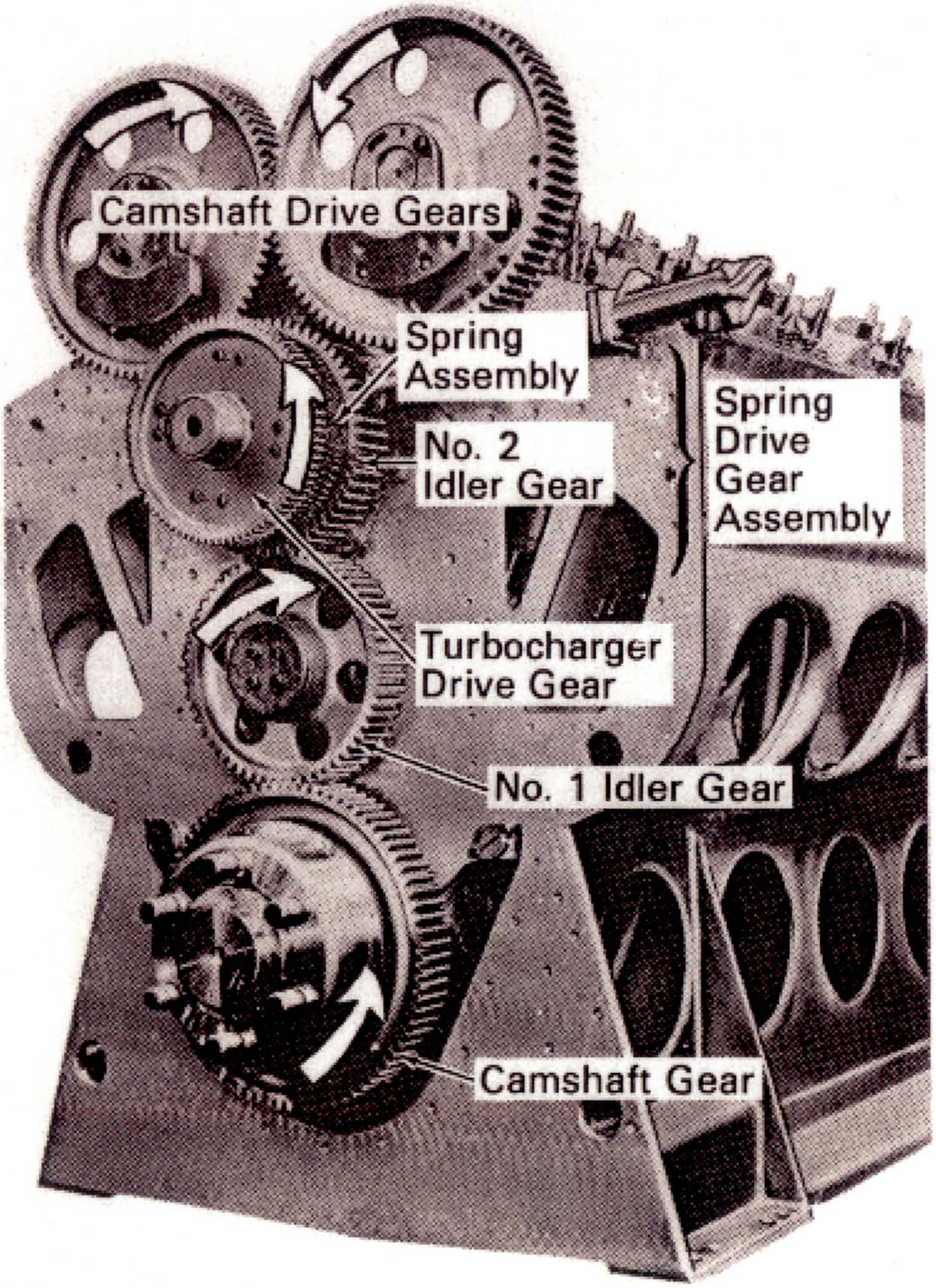


Figure 5
Turbocharger Assembly

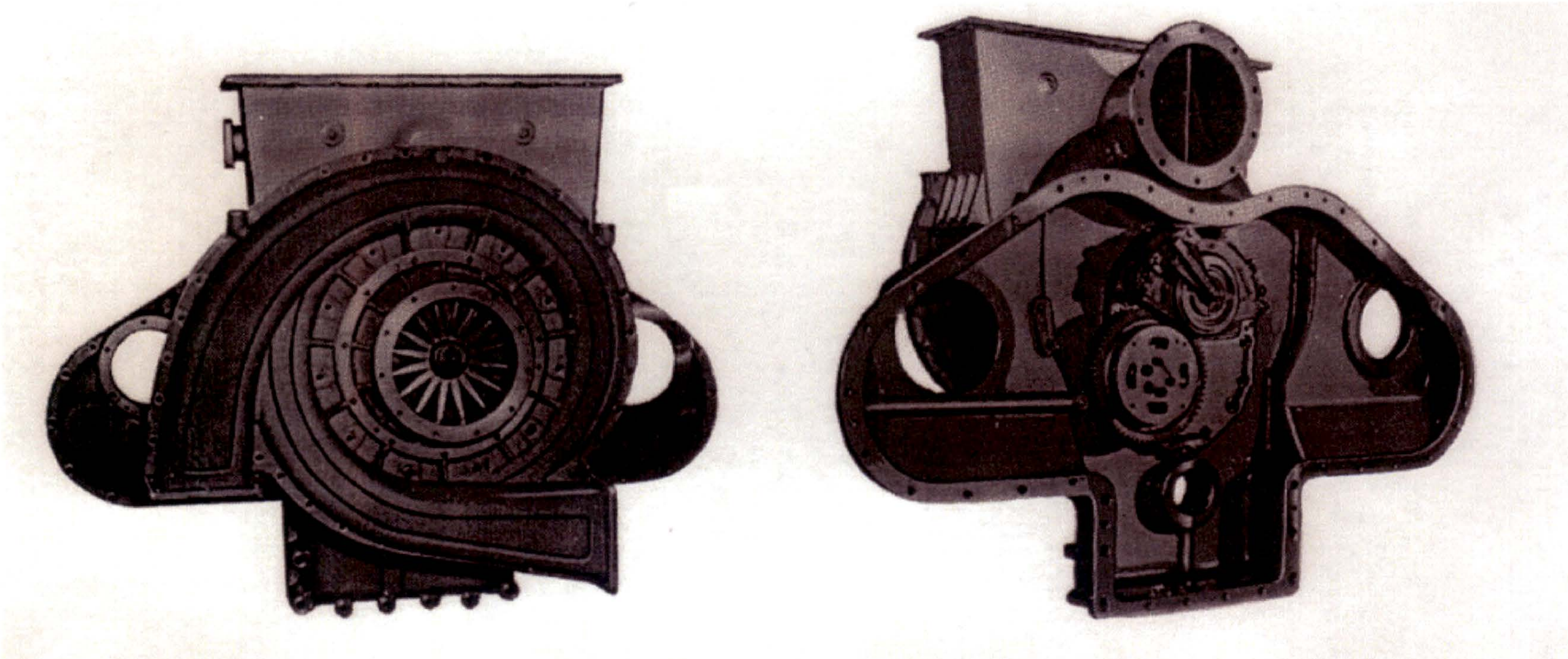
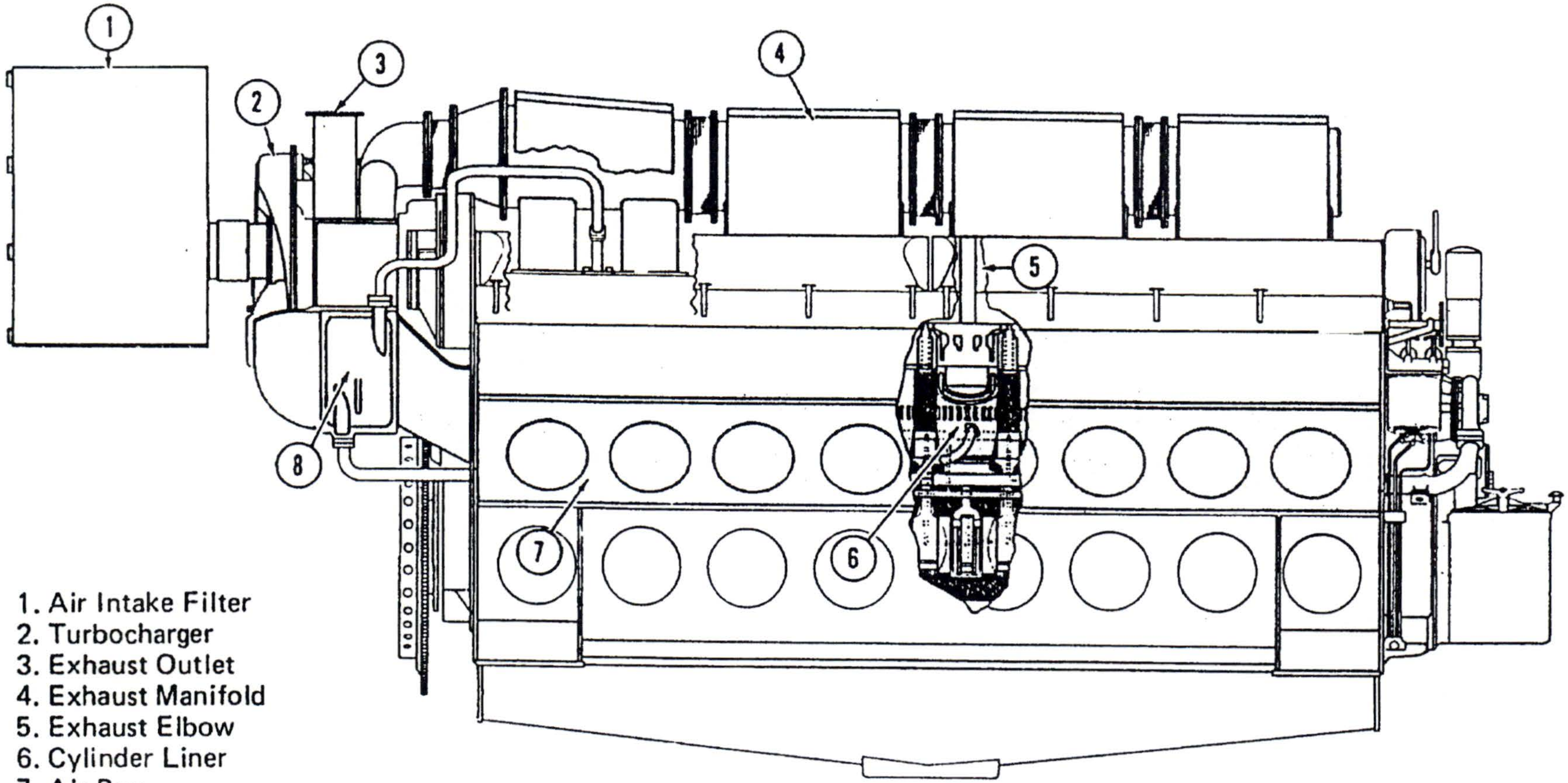
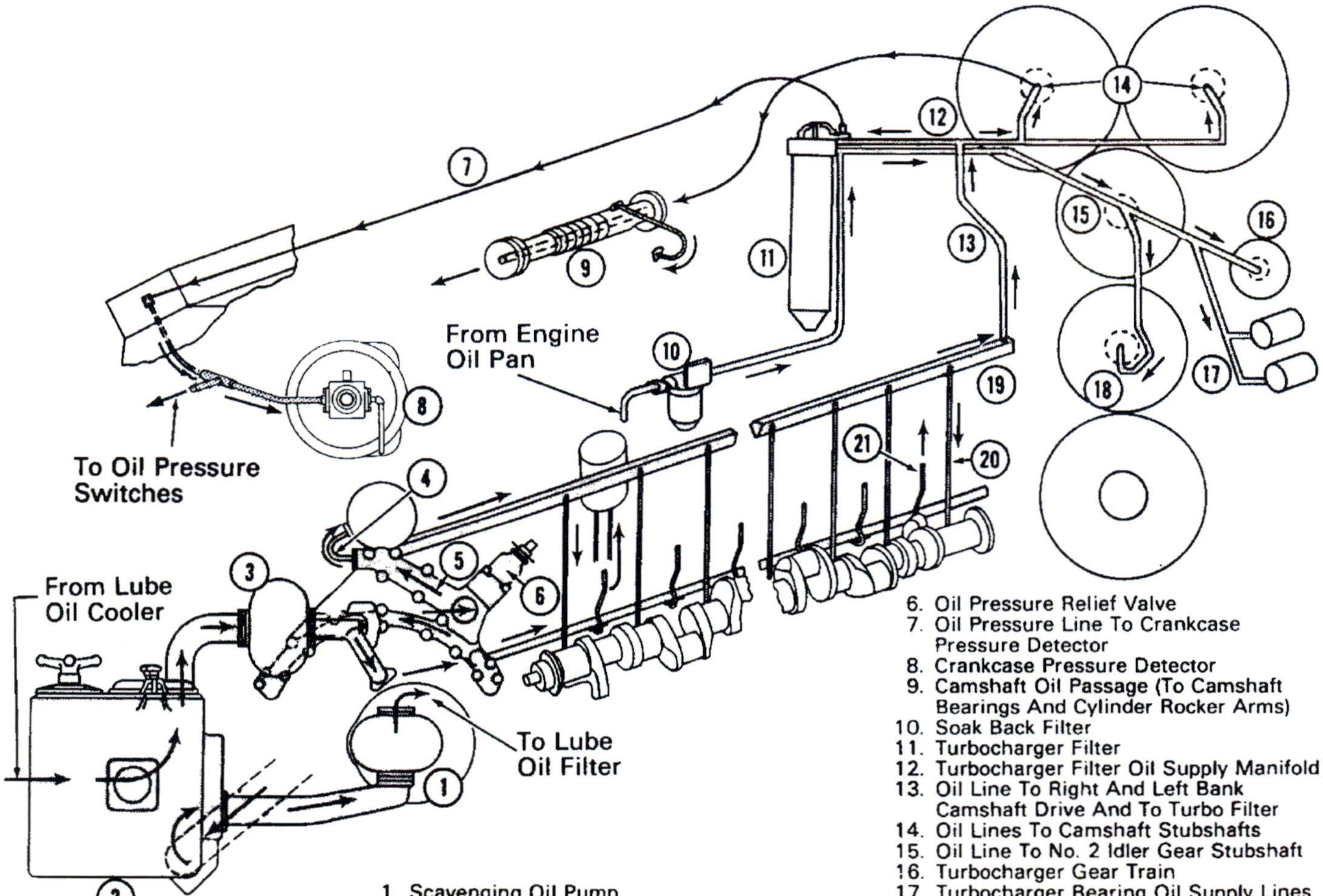


Figure 6
Cylinder Air Intake & Exhaust



1. Air Intake Filter
2. Turbocharger
3. Exhaust Outlet
4. Exhaust Manifold
5. Exhaust Elbow
6. Cylinder Liner
7. Air Box
8. Aftercooler

Figure 7
Lubricating Oil Internal Piping Arrangement



1. Scavenging Oil Pump
2. Oil Strainer Housing
3. Main Lube Oil And Piston Cooling Oil Pump
4. Oil Line To Governor Drive Gear Stubshaft
5. Main Lube Oil And Piston Cooling Oil Manifold
6. Oil Pressure Relief Valve
7. Oil Pressure Line To Crankcase Pressure Detector
8. Crankcase Pressure Detector
9. Camshaft Oil Passage (To Camshaft Bearings And Cylinder Rocker Arms)
10. Soak Back Filter
11. Turbocharger Filter
12. Turbocharger Filter Oil Supply Manifold
13. Oil Line To Right And Left Bank Camshaft Drive And To Turbo Filter
14. Oil Lines To Camshaft Stubshafts
15. Oil Line To No. 2 Idler Gear Stubshaft
16. Turbocharger Gear Train
17. Turbocharger Bearing Oil Supply Lines
18. Oil Line To No. 1 Idler Gear Stubshaft
19. Main Oil Manifold
20. Oil Supply To Crankshaft And Bearings
21. Piston Cooling Oil Line

Figure 8
Lubricating Oil Piping Arrangement

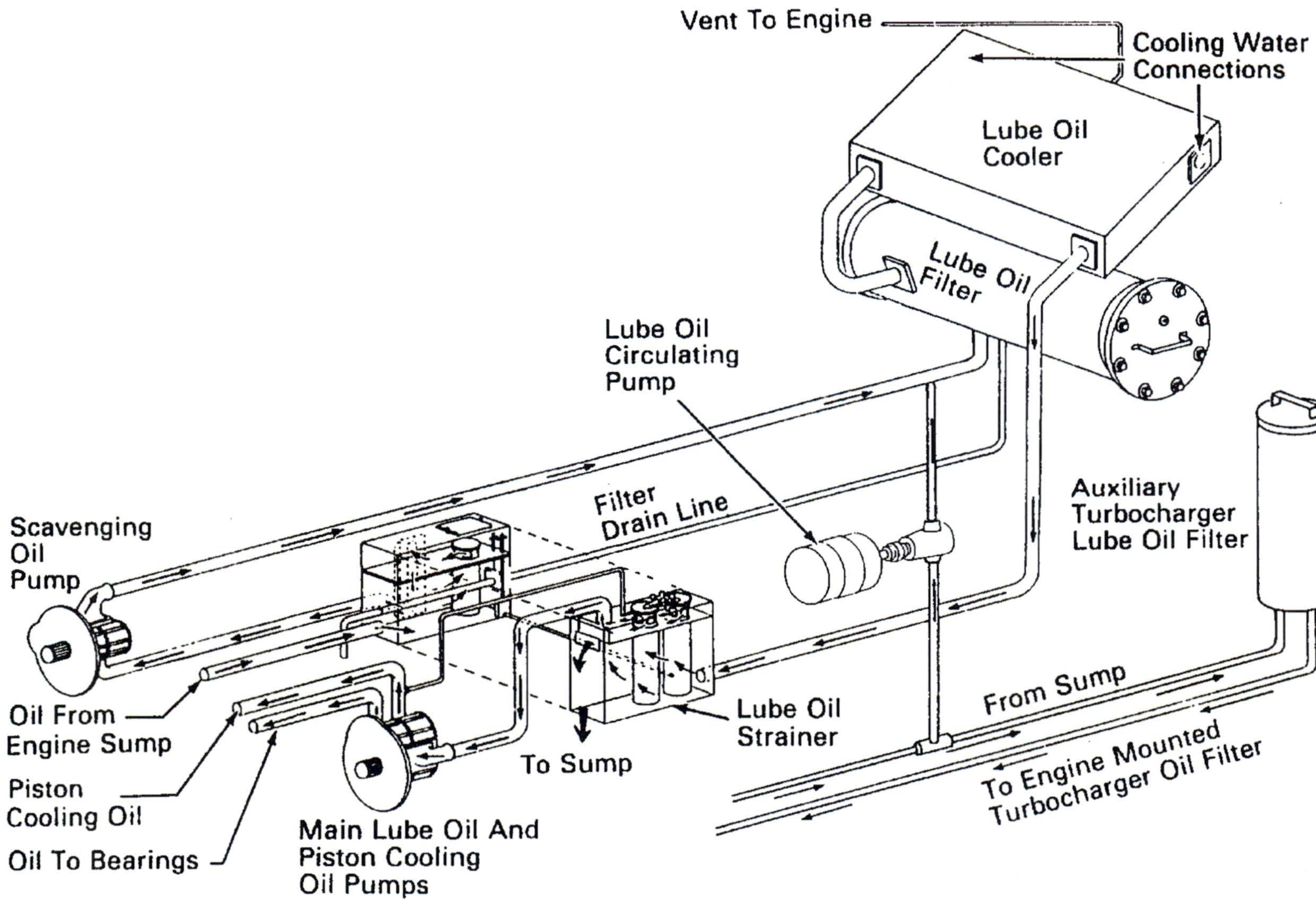


Figure 9
Cooling Water & Oil System Interface

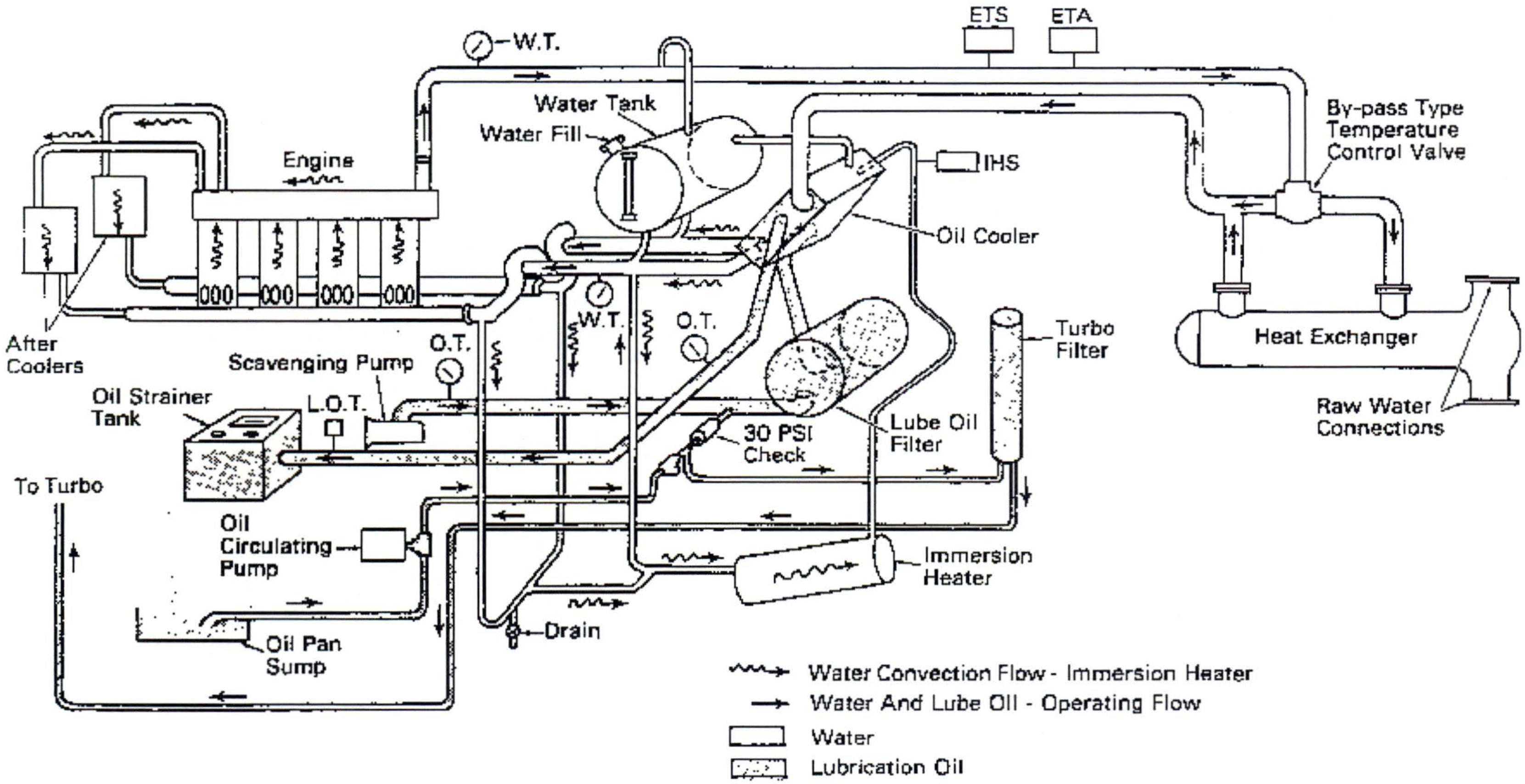


Figure 10
Fuel Oil Header Injector Arrangement

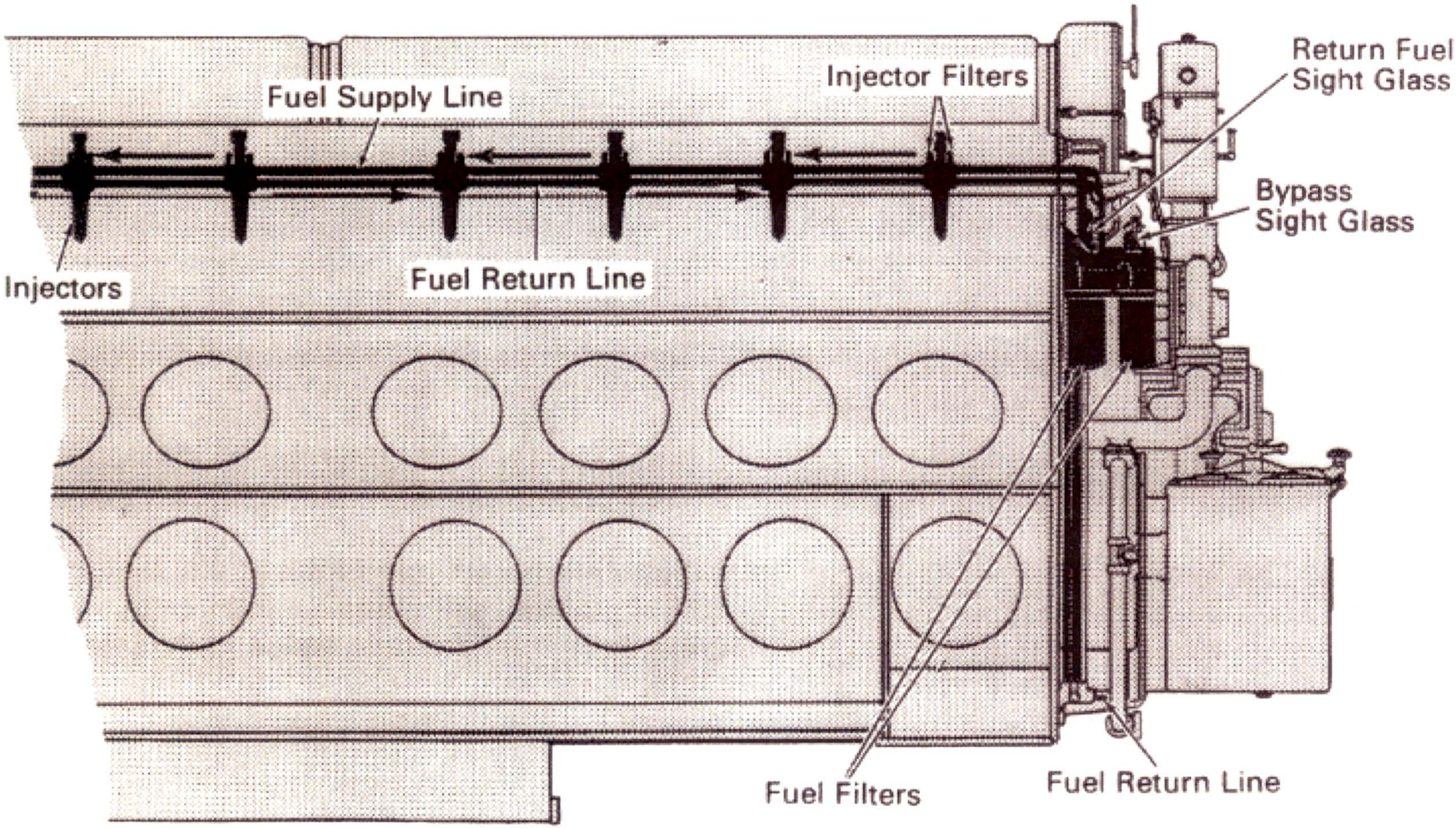


Figure 11
Lube Oil Strainer

Figure 11
Lube Oil Strainer

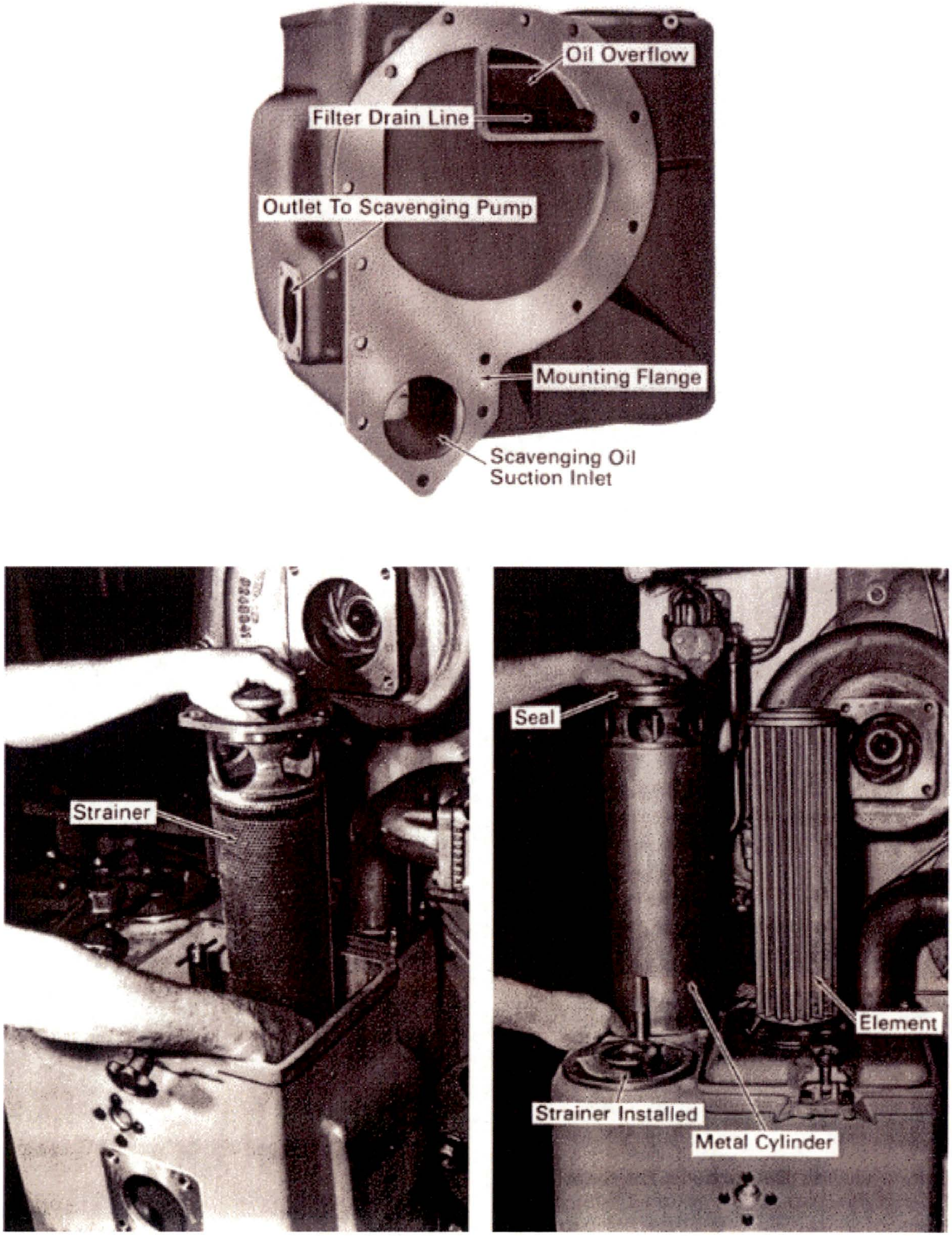


Figure 12
Lube Oil Strainer Internal Valve Arrangement

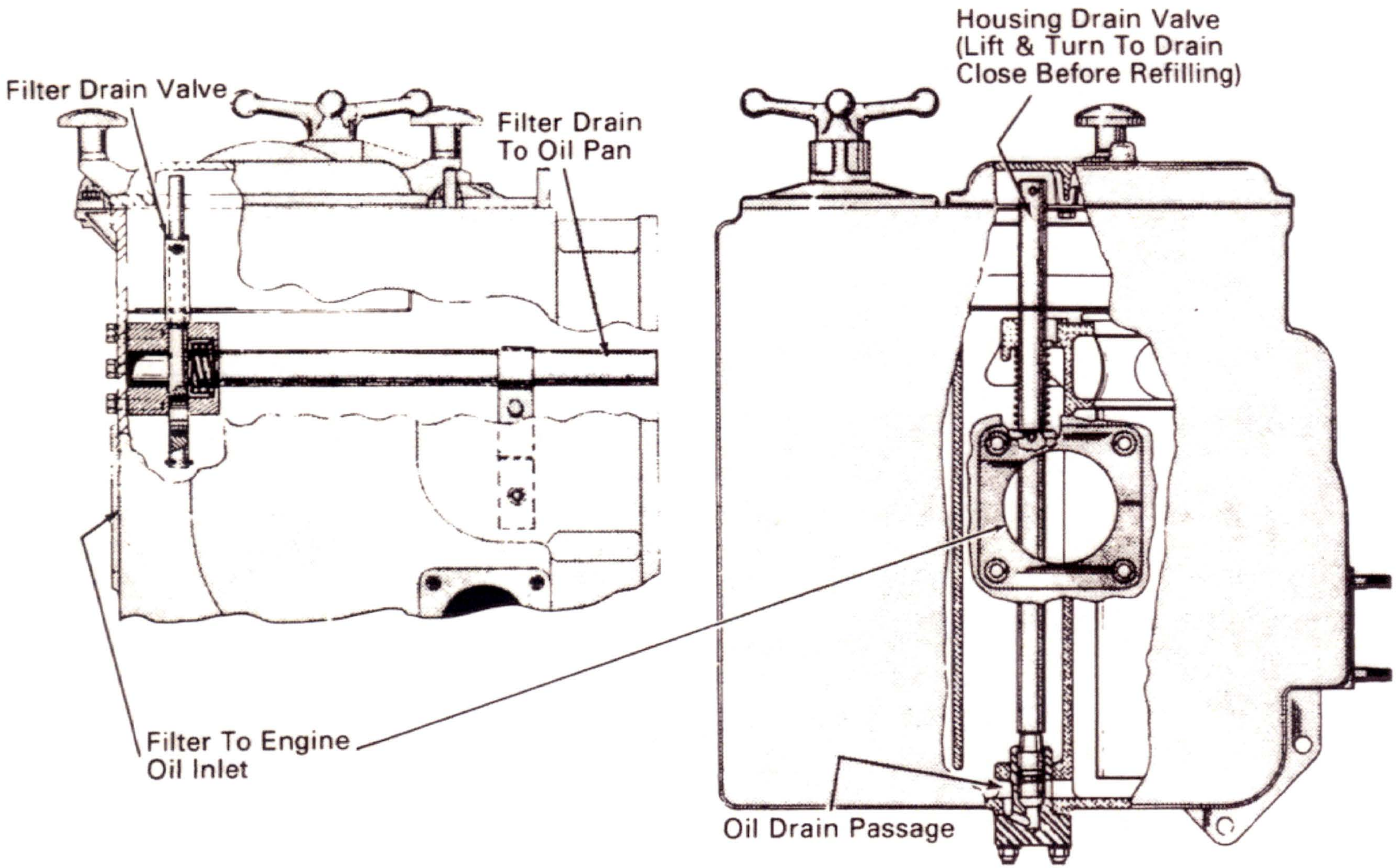


Figure 13
DG Start Logic

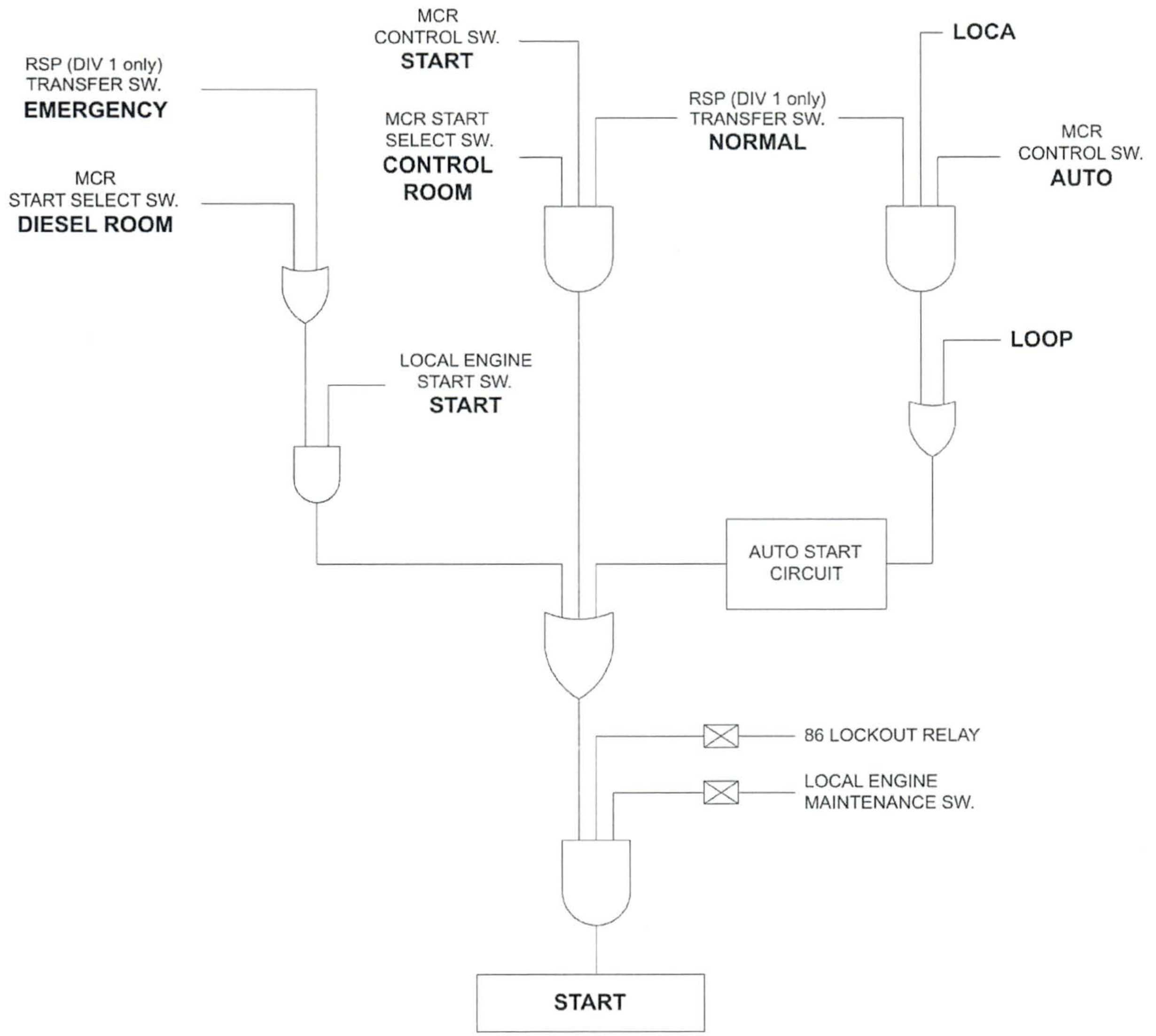


Figure 14
DG Stop Logic

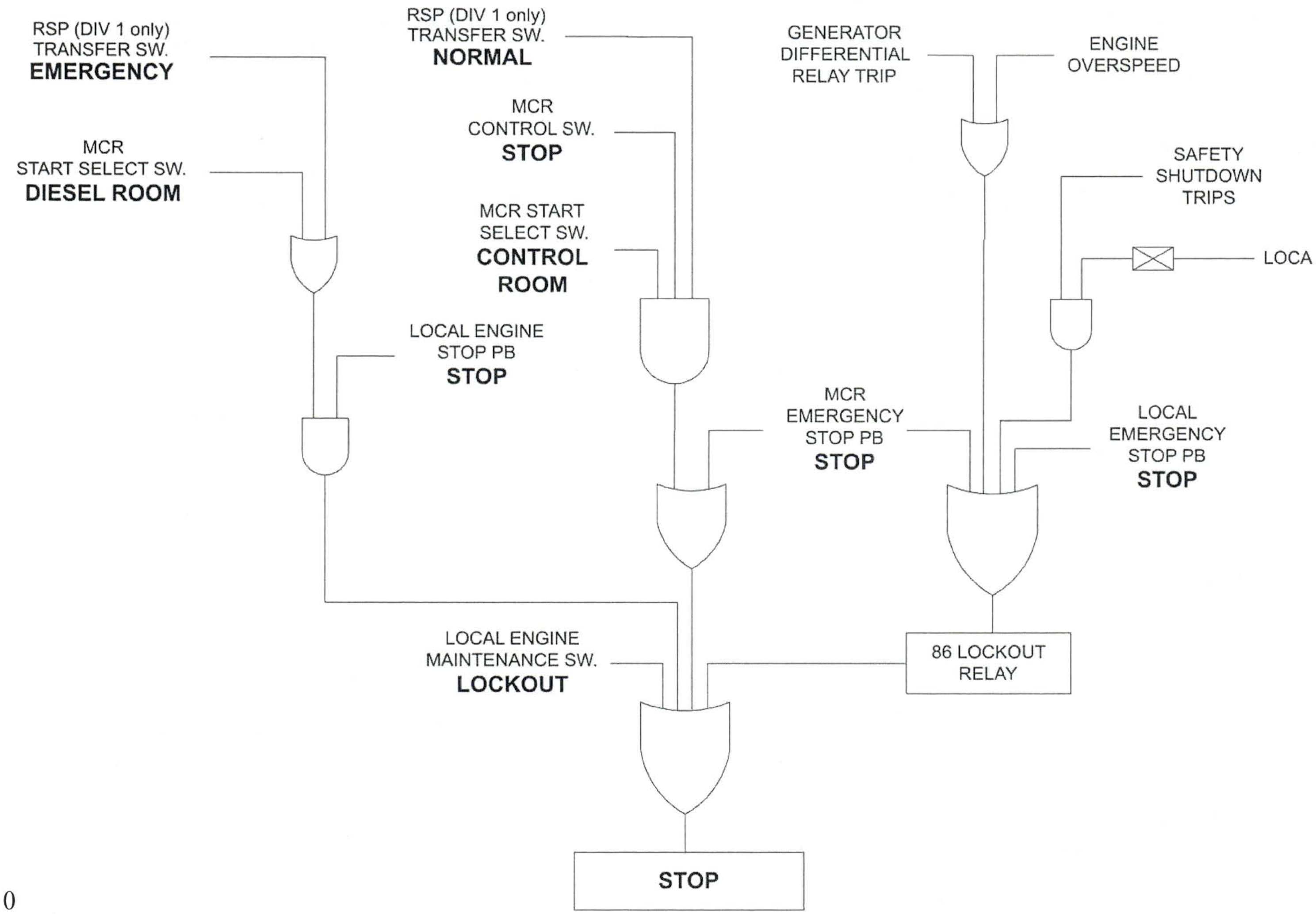


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Figure 15
DG Speed Control Logic

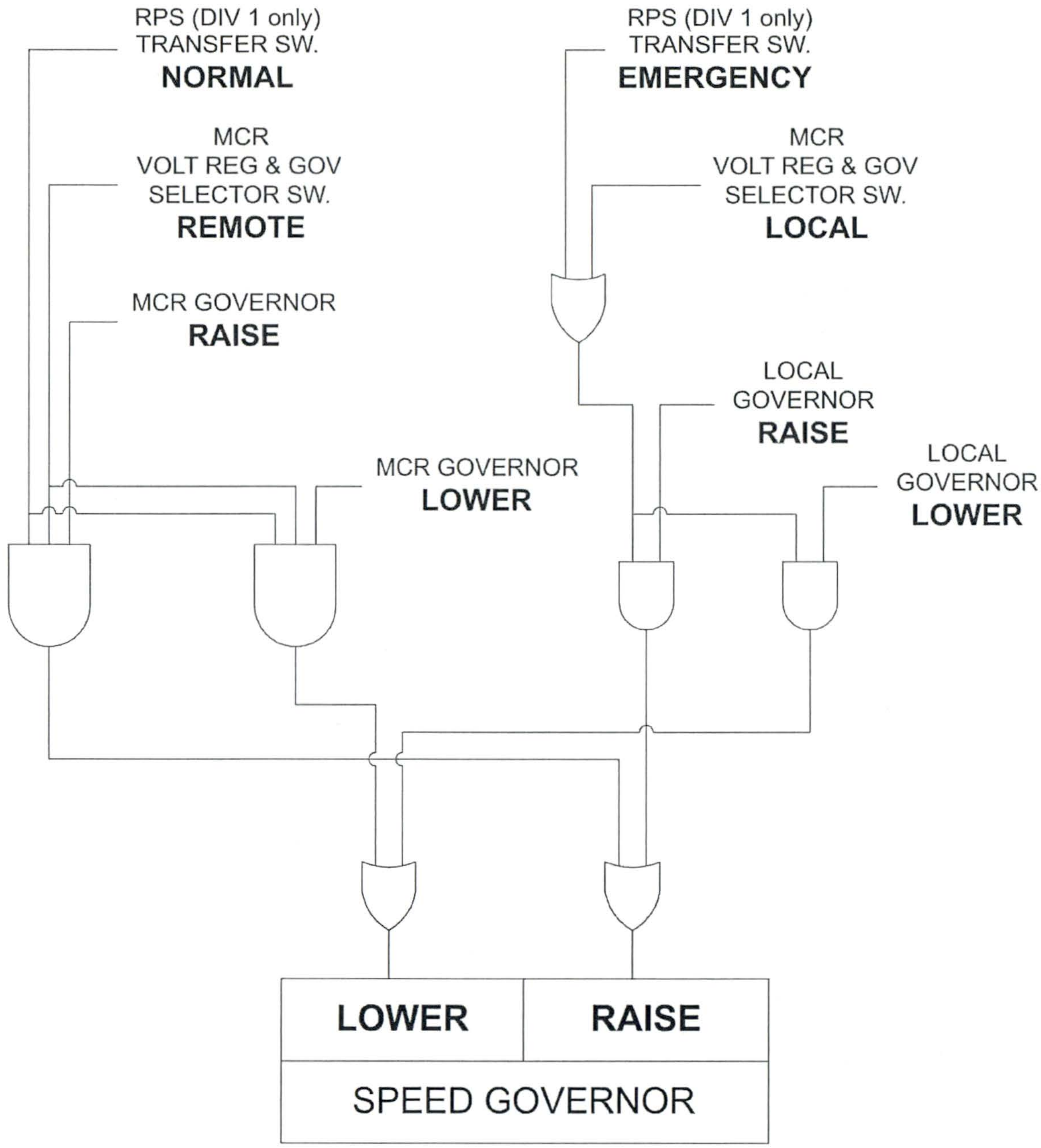
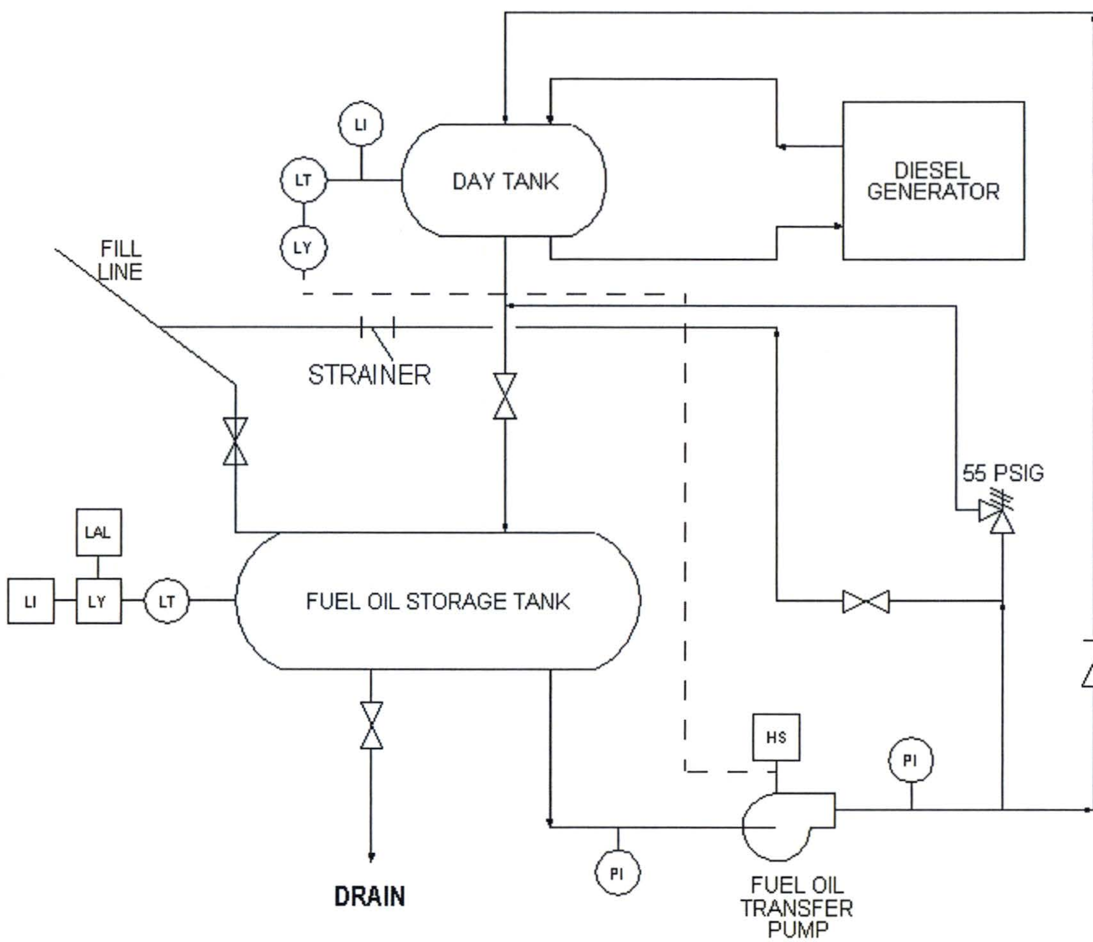


Figure 16
DG Fuel Oil Storage And Transfer System



DIESEL GENERATOR FUEL OIL STORAGE & TRANSFER SYSTEM

Figure 17
Engine Fuel Oil System

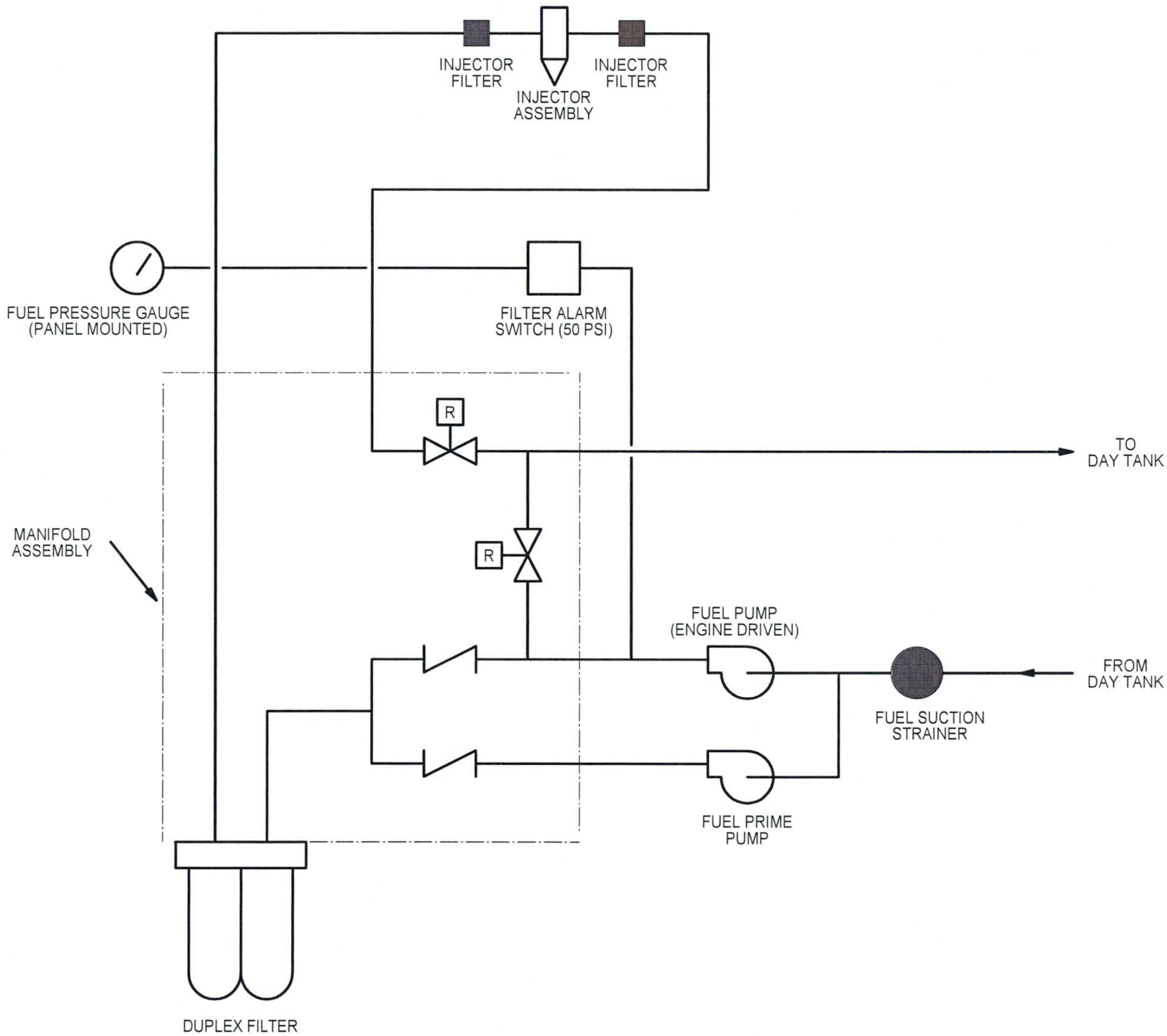


Figure 18
Div I & II Starting Air System

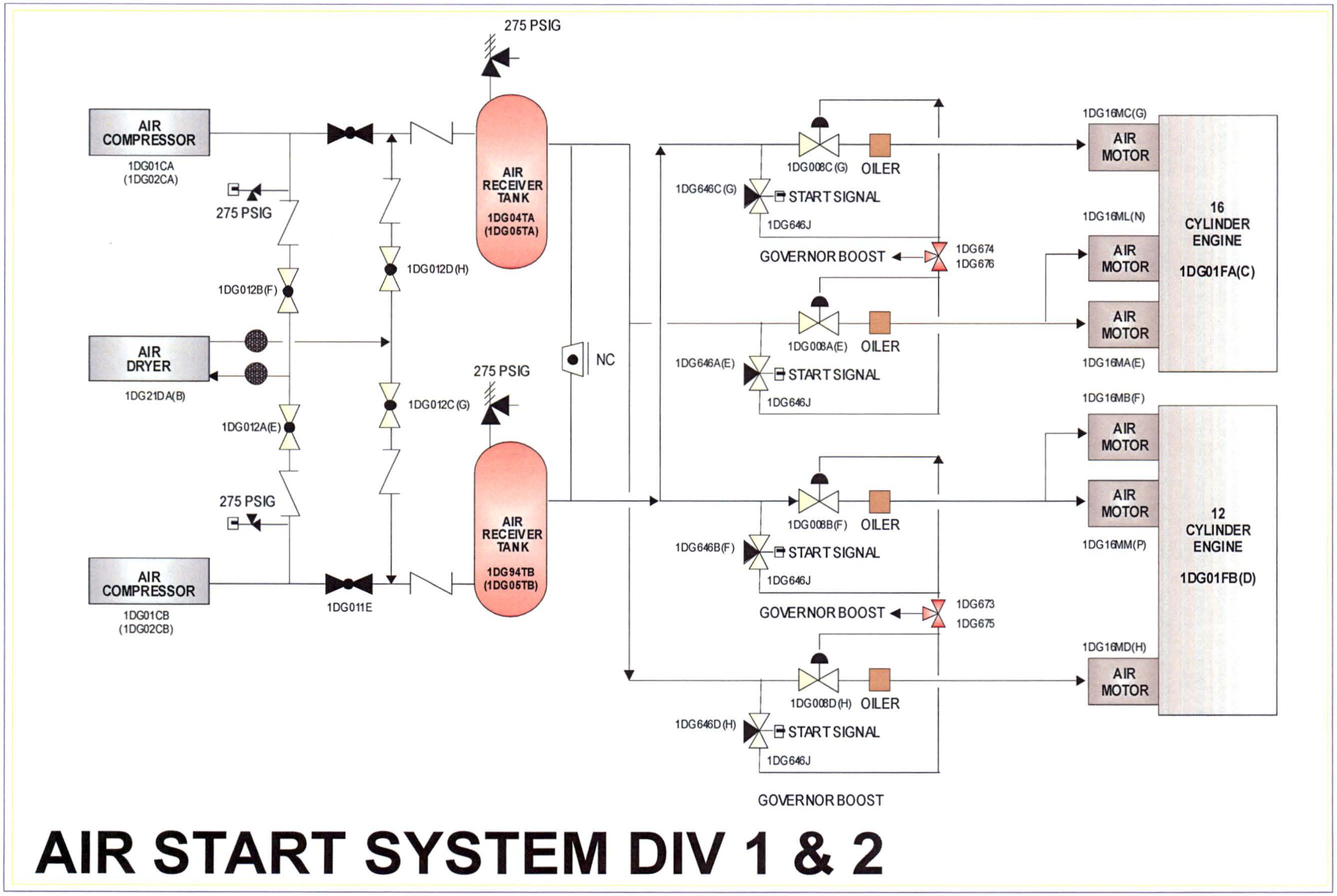


Figure 19
Div III Starting Air System

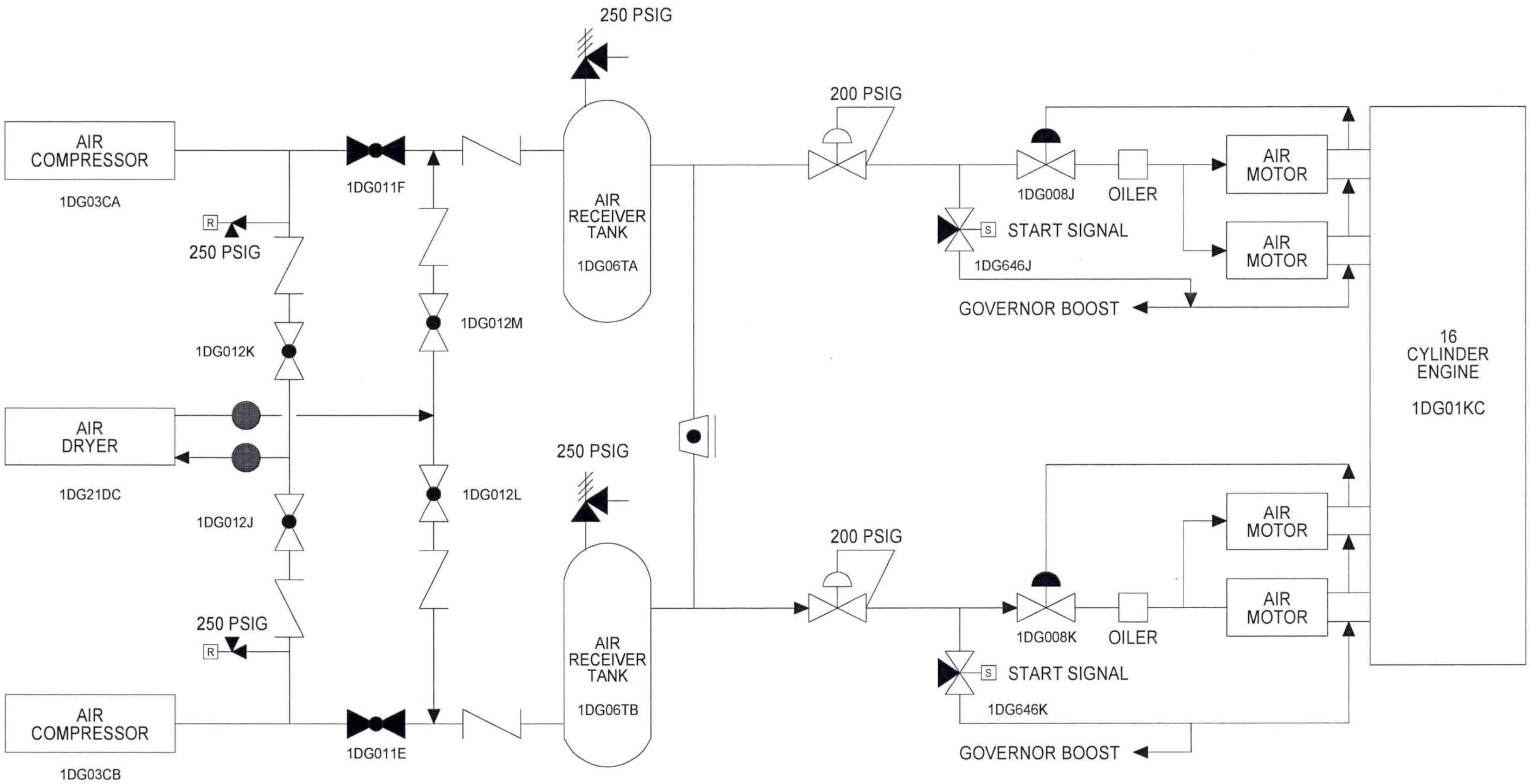


Figure 20
Lube Oil System

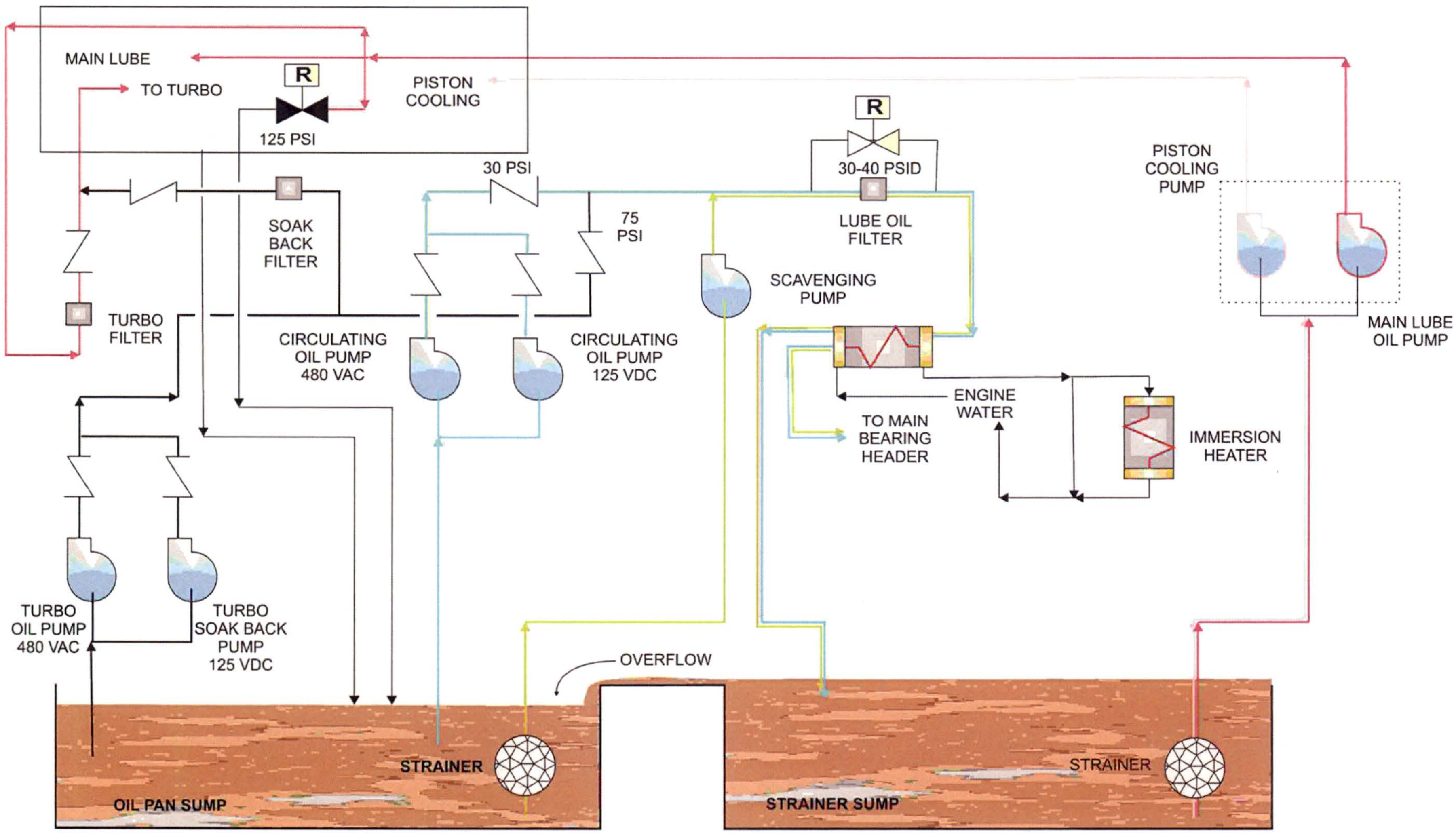


Figure 21
Cooling Water

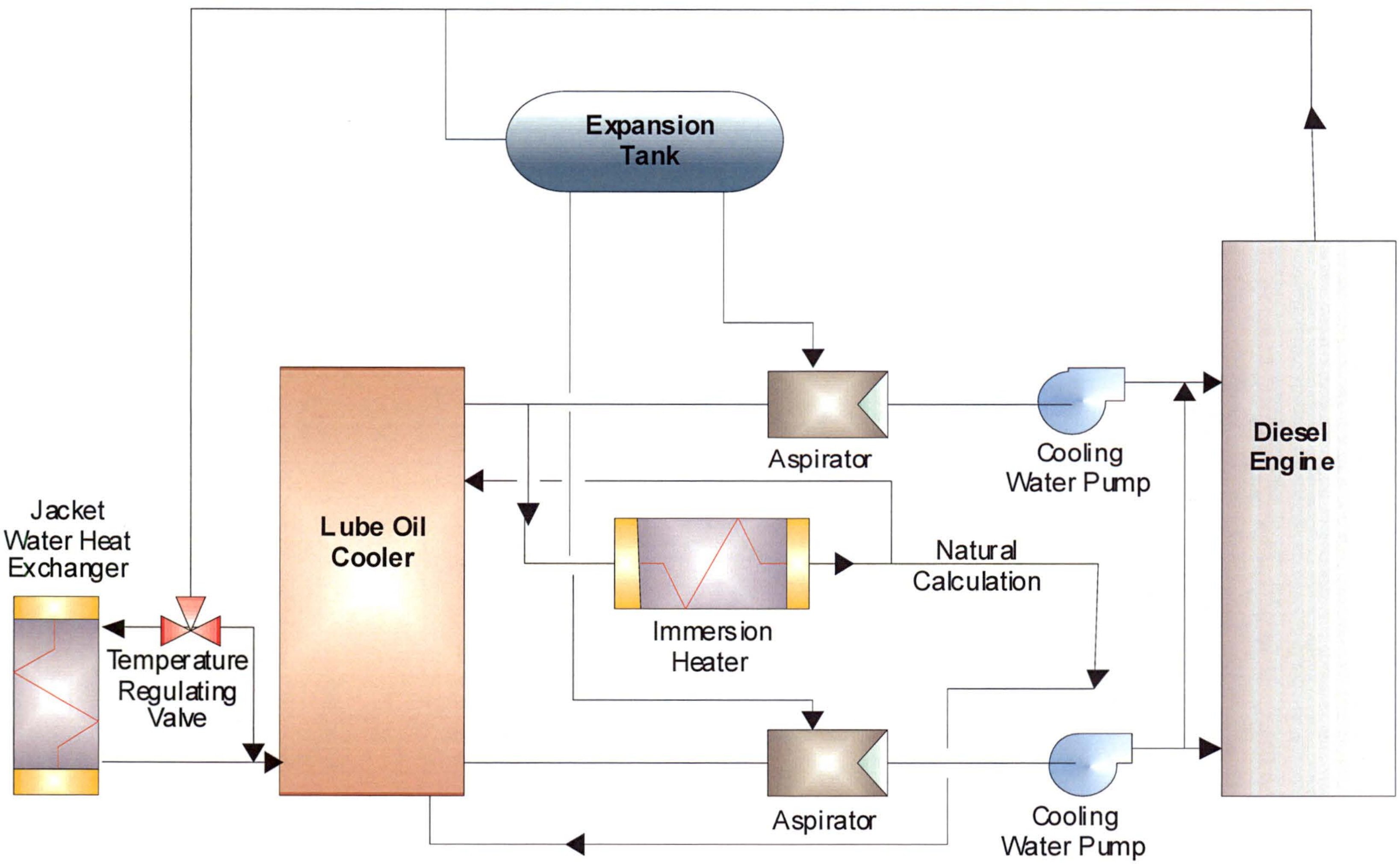


Figure 22
DIV 1,2 Speed Control

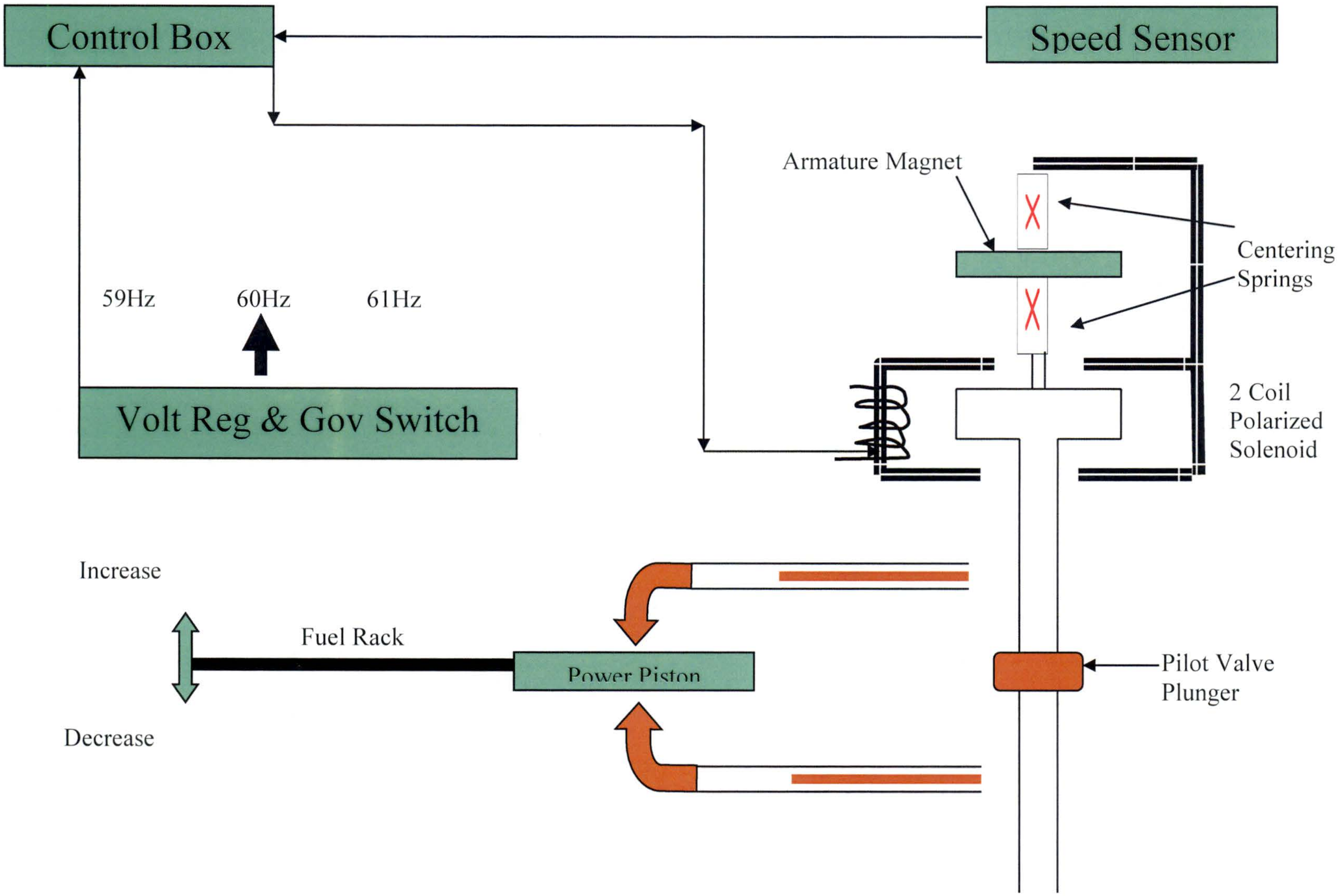
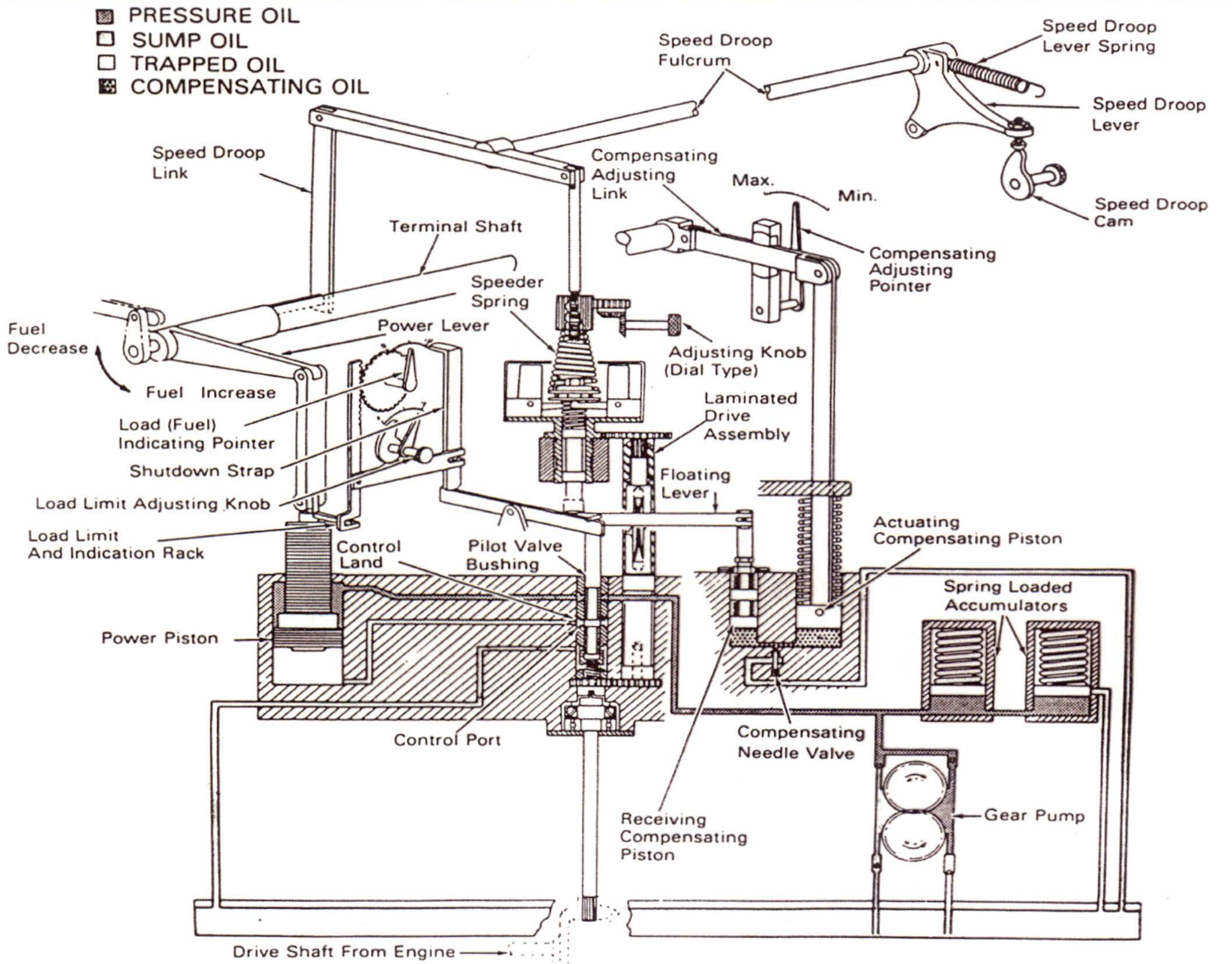


Figure 23
DIV III Governor



Governor Schematic

Figure 24
Div 1 DG Governor (New Model)

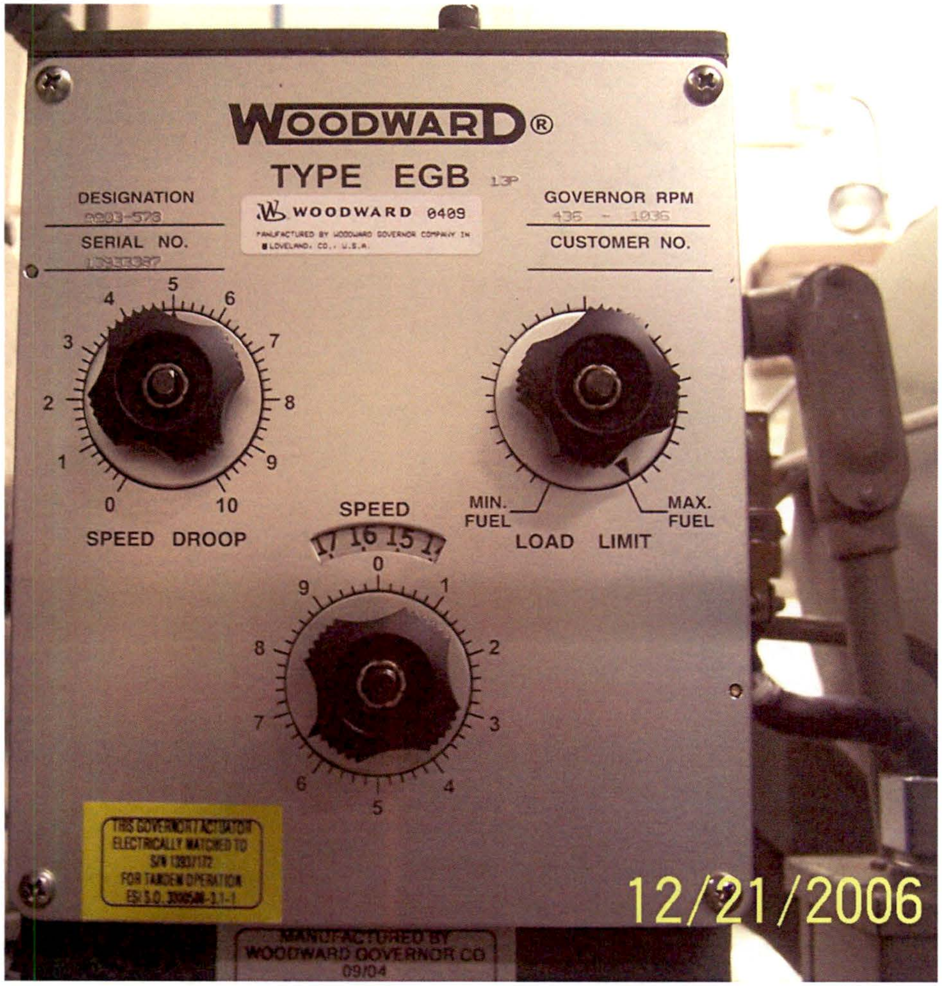


Figure 25
Keinie Valve

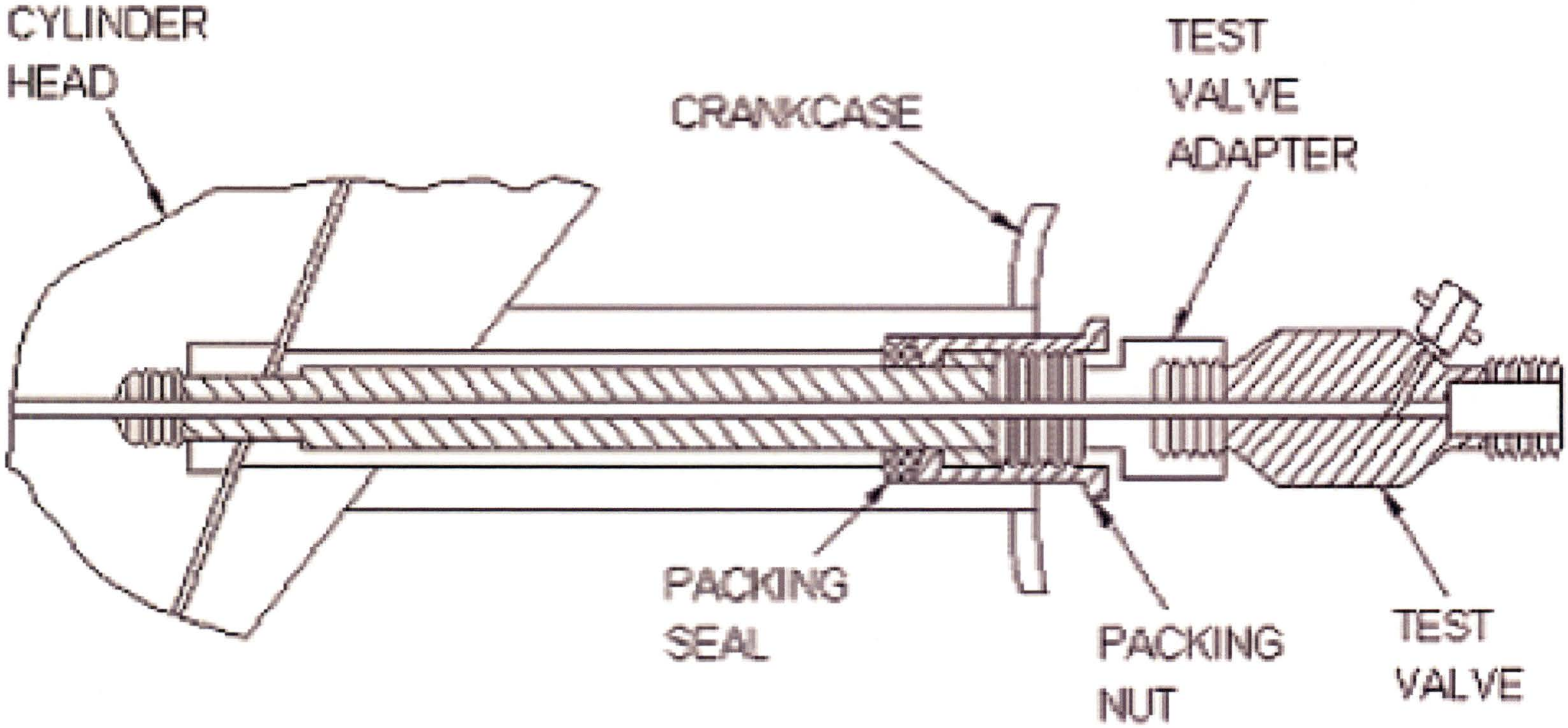


Figure 26
Keinie Valve with operator

A. **Safety Limits & Limiting Conditions for Operation (LCO's)**

3.3.8.1	Loss of Power (LOP) Instrumentation	Q: The plant is in Mode 1 and EMD discovers the Div. 1 "EDG Loss of Voltage Time Delay" as-found setpoint is 5.5 seconds. What are the required actions?
3.3.5.1 3.8.1	ECCS Instrumentation AC Sources Operating	Q: The plant is in Mode 1 and IMD discovers one of the four "HPCS Reactor Vessel Water Level – Low Low, Level 2" as-found trip setpoints is –50.2 inches. What are the required actions?

3.8.2	AC Sources – Shutdown	Q: The plant is in Mode 5 with the reactor cavity to steam dryer pool gate installed in preparation for drain-down for reactor reassembly. LPCS and A LPCI are OPERABLE. HPCS surveillance test results show a HPCS pump flowrate of 4,900 gpm at 365 psid. What are the required actions? Is the DIV 3 EDG required to be OPERABLE?
3.8.3	Diesel Fuel Oil, Lube Oil and Starting Air	Q. The plant is in Mode 1 with the Div. 2 EDG #2 starting air compressor clearanced out of service for an oil change. The clearance provides an open cross-connect valve to allow keeping the #2 Air Receiver associated with the out-of-service compressor charged. 'C' Area has a 4-hour comp action to verify both Div. 2 Starting Air Receiver pressures are > 200 psig. 'C' Area reports to the MCR that Div. 2 #2 Air Receiver is 138 psig, while #1 Air Receiver pressure is 250 psig. What are the required actions?

Document Based Instruction Guide

Course/Program:	LORT	Course Code:	N/A
Title:	Loss of AC Power	Guide #:	N-CL-OPS-DB-420001
Author:	Dave E. Crawford	Revision/Date:	001 / 10/16/2017
Revision By:	Mark McClure	Est. Teach Time:	1.5 Hours
Responsible site:	Clinton Power Station		

Qualified Nuclear Engineer Review (If applicable):	N/A	Date:	N/A
Training Supervision Review:	R. J. Frederes /S/	Date:	10/16/17
Program Owner Approval:	R. R. Kiss /S/	Date:	10/16/17

PREREQUISITES: None

OBJECTIVES:
In accordance with approved plant procedures and references, the trainee shall:

.1.1 Given specific plant conditions, determine if CPS No. 4200.01, LOSS OF AC POWER, should be used.

.1.2 State the reason for the following:

- .1 Selective tripping
- .2 De-energizing the Radiation Monitor Trip Logic power supply prior to restoring affected buses
- .3 Restoring 4160 Volt Bus 1B1 promptly
- .4 Securing RCIC Gland Seal Air Compressor prior to restoring the DIV I Diesel Generator to service

.1.3 Describe the operational implications of the following:

- .1 Station Blackout
- .2 Load shedding
- .3 Restoration of AC power
- .4 Transferring buses with a ground fault present

.1.4 Describe the consequences of the following:

  .1 Loss of AC power on the Reactor Recirc Pump Seals
  .2 Not completing DC load shedding in a timely manner during a Station Blackout
  .3 Energizing a Bus prior to locking out equipment with auto start features

.1.5 Describe when manual Turbine Generator jacking is required following a loss of AC power.

.1.6 Describe the available methods for monitoring specified plant parameters during a Station Blackout.

.1.7 Describe the guidelines for using RCIC during a Station Blackout.

.1.8 Describe the preferred sequence of system restoration following a loss of AC power.

.1.9 Describe the Plant Modification designed to prevent the Main Control Room from exceeding 120°F during a Station Blackout.

.1.10 Describe the effects of DC load shedding on the restoration of AC power.

.1.11 Given plant conditions involving a loss of AC power, and a copy of EP-AA-1003 (Radiological Emergency Plan Annex for Clinton Station) determine the Emergency Classification.

EVALUATION METHOD & PASSING CRITERIA:
A written exam with 80% passing criteria (when used). In the absence of a written exam, the evaluation method & passing criteria will be through questioning of class participants while ensuring full participation.

REFERENCES
1. CPS No. 4200.01, LOSS OF AC POWER
2. CPS No. 4200.01C001, MCR COOLING DURING A SBO
3. CPS No. 4200.01C002, DC LOAD SHEDDING DURING A SBO
4. CPS No. 4200.01C003, MONITORING CNMT TEMPERATURES DURING A SBO
5. CPS No. 4200.01C004, MANUAL CNMT ISOLATION DURING A SBO
6. CPS 3703.02C001, Irradiated Fuel Handling Checklist.
7. EP-AA-1003 Radiological Emergency Plan Annex for Clinton Station
8. SOER 10-02 (H.B. Robinson Steam Electric Plant Event – SER 3-10)
9. INPO 15-004 Operations Fundamentals
10. TR 01687009-81; DB420001 missed questions from 2016 ILT exam.
11. TR 02529709-84; Fuel Handling Loss of Power. (ITS 3.8.2, 3.8.5, 3.8.8, 3.8.10)
12. ITS 3.8 Electrical Power Systems and Bases.

ATTACHMENTS: None

COMMITMENTS: None

Revision 01 changes: Added two questions/Answers from TR 01687009-81; missed ILT questions. Added TR 02529709-84; Fuel Handling Loss of Power. (3703.02C001 Irradiated Fuel Handling Checklist.

I. INTRODUCTION

A. Introduce yourself:

1. Name
2. Position/responsibilities
3. Background/qualifications

B. Introduce subject matter

1. Procedure title/subject matter:
   CPS No. 4200.01, Loss of AC Power
2. Basis for instruction (check one)
   - ☐ New procedure/subject matter
   - ☐ Revised procedure/subject matter
   - ☒ Existing procedure/subject matter review
   - ☐ Other:

   Comments: None.

3. Establish relevance, importance, and purpose of topic

   Loss of AC electrical power is a fundamental element of nuclear safety because of the many safety and support systems that require it. Power sources must be protected from an inadvertent loss through sufficient defense-in-depth. During plant outage periods, there are frequently periods when equipment is not available and unusual electrical lineups exist. Maintenance activities performed during these periods increase the likelihood of an electrical perturbation and resultant system degradation. As a result, a good understanding of the impacts on a loss of AC power on the plant and its people and the effective resource utilization required for prompt but safe restoration of key electrical buses is essential for continued safe operation of the facility.

C. **Present Objectives:** (list below)

In accordance with approved plant procedures and references, the trainee shall:

.1.1 Given specific plant conditions, determine if CPS No. 4200.01, LOSS OF AC POWER, should be used.

.1.2 State the reason for the following:

- .1 Selective tripping
- .2 De-energizing the Radiation Monitor Trip Logic power supply prior to restoring affected buses
- .3 Restoring 4160 Volt Bus 1B1 promptly
- .4 Securing RCIC Gland Seal Air Compressor prior to restoring the DIV I Diesel Generator to service

.1.3 Describe the operational implications of the following:

- .1 Station Blackout
- .2 Load shedding
- .3 Restoration of AC power
- .4 Transferring buses with a ground fault present

.1.4 Describe the consequences of the following:

- .1 Loss of AC power on the Reactor Recirc Pump Seals
- .2 Not completing DC load shedding in a timely manner during a Station Blackout
- .3 Energizing a Bus prior to locking out equipment with auto start features

.1.5 Describe when manual Turbine Generator jacking is required following a loss of AC power.

.1.6 Describe the available methods for monitoring specified plant parameters during a Station Blackout.

.1.7 Describe the guidelines for using RCIC during a Station Blackout.

.1.8 Describe the preferred sequence of system restoration following a loss of AC power.

.1.9 Describe the Plant Modification designed to prevent the Main Control Room from exceeding 120°F during a Station Blackout.

.1.10 Describe the effects of DC load shedding on the restoration of AC power.

.1.11 Given plant conditions involving a loss of AC power, and a copy of EP-AA-1003 (Radiological Emergency Plan Annex for Clinton Station) determine the Emergency Classification.

II. DESCRIPTION OF PROCEDURE/SUBJECT MATTER

A. Management Expectations

1. Safe nuclear power plant operation is based upon the principle that each individual accepts the unique and grave responsibility inherent in using nuclear technology.

2. When operations personnel are faced with unexpected or anomalous system behavior, they are expected to take conservative action to place the system/plant in a safe condition.

3. A thorough understanding of the Loss of AC Power offnormal is desired for an individual to recognize the actions required, that are designed to restore/maintain plant systems and components to fulfill safety functions.

4. Traits of a Strong Nuclear Safety Culture assures behaviors and actions of all support a culture of safety in all aspects of plant operation. Cornerstones of these principles are:
   - Everyone is personally responsible for nuclear safety.
   - Leaders demonstrate. commitment to safety
   - Trust permeates the organization.
   - Decision-making reflects safety first.
   - Nuclear technology is recognized as special and unique.
   - A questioning attitude is cultivated.
   - Organization learning is embraced.
   - Nuclear safety undergoes constant examination.

5. Discuss how INPO 15-004, Operations Fundamentals are utilized during Loss of AC Events:
   - Monitoring plant indications and conditions closely.
   - Controlling plant evolutions precisely.
   - Operating the plant with a conservative bias.
   - Working effectively as a team.
   - Having a solid understanding of plant design, engineering principles and sciences

B. DESCRIPTION OF PROCEDURE/SUBJECT MATTER

Instructions: *Use a copy of the latest revision of the procedure(s)/subject matter for presentation of this section. Present the document covering it to the extent required to meet the objectives. Involve the trainees in discussion and questions to keep them active and interested. Provide adequate guidance to the instructor in this section for instructional activities and content to support achievement of objectives. Sufficient detail must be contained in this section such that there is repeatability of the instruction if the material is presented by an instructor other than the author. Scripted questions should be included in this section of the DBIG to support learning and to check for understanding. Add as many lines/pages as needed. In addition, if only select parts of the reference document are to be taught, indicate the items below. Consider addressing the following items in the training content as applicable:*

- *Why is this task performed?*
- *What does the task accomplish?*
- *What is the importance of the task with respect to plant safety?*
- *What are the consequences of performing the task incorrectly?*
- *How will the plant respond?*
- *What are the bases of procedure precautions, limitations and actions, and pre-requisites?*
- *What steps are critical for completing the task correctly?*

Include Exelon Fundamentals and relevant OPEX including applicable SOER 10-2 must-know OPEX in the training material content

1. <u>Review Section 1.0 - Symptoms</u>

Q. What major loads will be taken out of service on the loss of 6.9 KV Bus 1B?

A. 'B' RR Pump, the 'B' CW Pump & the MDRFP

Q. What major plant equipment will be out of service due to the loss of 4.16 KV Bus 1B?

A.

- CD/CB pumps B & D
- WS pump B
- CC pump B
- SA compressor 1&2
- WO chillers D & E
- RD pump B
- RR LFMG Set B
- CA pump B

Q. What major plant equipment is lost when 4.16 KV Bus 1B1 is de-energized?

A.

- RHR Pumps B & C
- SX Pump B
- VP Chiller B
- FC pump B
- CMNT IA Isolation Valves (Div 2)
  - Control Rods drift in
  - MSIVs close
  - RT F/D FCVs close & trip RT pumps
  - RPV level via RT Letdown will become unavailable.
- TBMCC 1M
  - MDRFP Aux Oil Pump
  - FW004 Hydraulic pump
  - Main Turbine Turning Gear
  - TDRFP A & B Turning Gear
  - Main Seal Oil pump
  - Seal Oil Vacuum pump
  - RR Aux Seal Injection pump

2. **Review Section 2.0 – Automatic Actions**

Q. Assume the ERAT is out of service and RAT 'B' is supplying power to 4.16 KV Bus 1A1, 1B1 & 1C1. What is the impact on these safety related buses if RAT 'B' fails resulting in a degraded voltage condition?

A. After a 15 sec time delay with degraded voltage, the secondary under voltage relays will strip the 1A1, 1B1 & 1C1 buses, start the associated DGs, and then tie the DGs onto their respective buses with 12 seconds. Loads will be automatically connected to the ECCS bus as required by ECCS initiation logic.

Q. What automatic actions will occur in the seal oil & turbine oil system if ECCS bus 1B1 is de-energized?

A. The Emergency Seal Oil Pump and the Emergency Bearing Oil Pump will automatically start.

Q. How is the Fire Protection System impacted on a loss of 6900V 1A Bus?

A. The respective fire pump (OFP01PA) will start.

Q. When a 6.9 KV bus trips and locks out what happens to the 480V buses?

If the 480V bus has a cross-tie breaker, the 480V bus cross-tie breaker will (assuming no 480V bus fault) auto close to re-energize the 480V bus.

3. **<u>Review Section 3.0 – Immediate Operator Actions</u>**

4 **<u>Review Section 4.0 – Subsequent Actions</u>**

a. ITS 3.8.2, 3.8.5, 3.8.8, and 3.8.10 all require Operable AC/DC power systems 'During movement of irradiated fuel assemblies in the primary or secondary containment'.

b. These ITS actions call for <u>immediate suspension of Fuel handling activities</u>. See ITS 3.8.2/3.8.5 /3.8.8/3.8.10 and CPS 3703.02C001, Irradiated Fuel Handling Checklist. (TR 02529709-84; Fuel Handling Loss of Power)

5. **<u>Review Section 5.0 – Final Conditions</u>**

6. **<u>Review Section 6.0 – Discussion</u>**

C. **<u>OPEX</u>**

Discuss the INPO 15-004, Operations Fundamentals that could have prevented the following events:

a. Monitoring plant indications and conditions closely.
b. Controlling plant evolutions precisely.
c. Operating the plant with a conservative bias.
d. Working effectively as a team.
e. Having a solid understanding of plant design, engineering principles and sciences

1. OPEX – Review SOER 10-02 (H.B. Robinson Steam Electric Plant Event – SER 3-10) and discuss its significance to a loss of AC power and the lessons learned.

2. **Clinton Scram due to Loss of Div 1 Unit Substations** 12/08/2013 @2027 – ENS# 49617. MANUAL SCRAM DUE TO LOSS OF DIVISION 1 480 VAC POWER CAUSING LOSS OF INSTRUMENT AIR TO CONTAINMENT AND SCRAM AIR HEADER

While operating at rated power, the station experienced a Div. 1 480 VAC Transformer fault which resulted in a loss of Division 1 480 VAC power. This resulted in the operators inserting a Manual Scram due to Closure of Instrument Air Valves to Containment and the scram air header. On the scram, all control rods fully inserted and no safety relief valves lifted. Reactor vessel level is being maintained by normal feedwater and decay heat is being removed via steam to the main condenser through the steam bypass valves. The plant is currently in Mode 3 and proceeding to Mode 4 to comply with Technical Specification requirements. The plant is in a normal shutdown electrical lineup with the exception of the loss of Division 1 480 VAC power.

Reporting in accordance with 10CFR50.72(b)(3)(v)(C) due to loss of normal ventilation to secondary containment which resulted in a positive secondary containment pressure for approximately 15 minutes. Secondary Containment required pressure was restored at 2043 CST.

Reporting in accordance with 10CFR50.72(b)(3)(v)(D) due to loss of Division 1 480 VAC power resulting in loss of a single train of Low Pressure Core Spray.

D. Review Questions

Q. In general, which AC Bus breakers use DC control power and how does this affect MCR indication?

A. 6.9 KV bus breakers, 4.16 KV bus breakers & 480V feeder breakers.

The RED and GREEN breaker position indications in the MCR reflect breaker CLOSED and OPEN status, respectively. The GREEN indication is lit when the breaker is OPEN with control power available to the breaker closing logic. The RED indication is lit when the breaker is CLOSED with control power available AND there is a complete circuit path through the breaker trip circuit. A small electrical current (which is enough to light the RED indication in series with the trip coil but not enough to energize the trip coil itself) is used to give reasonable assurance to the MCR staff the breaker will open when required. A RED indicating light which is not energized when expected (i.e. when the breaker is closed) may not trip open (either manually from the MCR or automatically) if the lack of closed indication is due to a fault in the control power supply or in the trip circuit itself. This can lead to equipment damage, a fire or result in personnel injury should a bus overcurrent condition occur.

Q. What actions are required if RR Seal CCW cooling is lost to both RR pumps?

A. Scram reactor and within one minute, secure both RR Pumps. Perform an Emergency RR Loop A & B Shutdown per the CPS 3302.01 Hardcard.

Q. What actions are required if RR Seal injection flow is lost?

A. RR pump operation may continue due to internal seal flow and external cooling provided by CCW.

Q. What actions are required if both RD Seal Injection <u>and</u> CCW Cooling Flow is lost to both RR Pumps?

A. Scram reactor and within one minute, secure both RR Pumps. Perform an Emergency RR Loop A & B Shutdown per the CPS 3302.01 Hardcard including shutting 1B33-F075A & B (Pump Seal Stag Shutoff Valves). Isolate both RR loops per the Hardcard.

Q. Where can RR pump seal temperatures be monitored on PPC?

A. PPC "RR Pump Parameters" Group Point

Q. What actions are required by CPS 4008.01 if no RR pumps are running with the MODE switch in RUN?

A. SCRAM

Q. With 4.16 KV 1B1 de-energized what sources of RPV makeup are/will be available when MSIVs close?

A. RCIC, HPCS, CRD pumps A/B, CD/CB through FW003A/B (<600 psig in the RPV)

Q. In generic terms, when should CPS No. 4200.01, Loss of AC Power be entered?

A. Any interruption of power on an AC bus which results in:

1. Automatic transfer of the bus to any alternate source (except a main generator trip due to reasons other than electrical problems), or
2. Loss of voltage, current and watts on the bus, or
3. Bus under voltage, auto transfer of feeder breaker, breaker tripped, breaker not available, and transfer blocked alarms on the bus(es).

Q. Why is selective tripping used here at CPS?

A. Selective tripping ensures that the minimum section of electrical distribution is affected due to a fault by isolating the bus as near the fault as possible.

Q. Why is it important to de-energize the Radiation Monitor Trip Logic power supply prior to restoring affected buses powering the Rad Process Monitors?

A. When restoring buses associated with Appendix C of CPS 4200.01, the trip logic power supply breakers are opened to prevent an inadvertent actuation/ isolation when bus power is restored (i.e. the rad monitor devices are re-energized).

Q. Why should the 4160V Bus 1B1 be restored promptly after being lost?

A. Energize Bus 1B1 promptly to restore turbine oil and Turning Gear for the TG and Seal Oil to the Generator. Additionally, restoration of 4160V Bus 1B1 aids in area access capability due to recovery of the security system.

Q. Why should the RCIC Gland Seal Air Compressor be secured prior to restoring the DIV I Diesel Generator to service during a Station Blackout (SBO)?

A. Ensures sufficient D/G field flashing current on DG start sequence.

Q. How are under/degraded voltage, load shedding and restoration apply to the CPS safety related busses?

A. Two levels of undervoltage protection are provided.

- Level 2 relays for degraded voltage are set at a nominal bus voltage of 4072 volts for all three Divisions.
- After the Secondary Under Voltage Relay 15 sec time delay times, the Divisional DG will start; the Divisional Reserve (Main) feeder will open & the Divisional Main (Reserve) feeder will lock out.
- The Div 1 & 2 buses are stripped of their loads (load shedding) when a Level 1 voltage is sensed (caused by the above action) and the respective DG will tie onto the bus within 12 seconds. The Level 1 voltage relays are set at nominally 2870 volts (Div 1 & 2) and 2538 volts (for Div 3).

If Div. 1 or 2 DGs automatically connect to their respective buses after load shedding, the bus loads are sequentially started provided an associated initiation signal is present.

- This sequence will keep the bus voltage and frequency within the required limits.
- Div 3 loads are not shed nor are they sequenced.

All 4.16 KV loads for Div. 1 and 2 buses are tripped on loss of bus voltage except feeders to 480V Unit Substations A, B, 1A, and 1B.

- Drywell Chillers and Fuel Pool Cooling Pumps require manual start.
- The remaining loads are LPCS, the SX Pumps and the RHR pumps.

After restoration of bus voltage, they are sequenced on their respective divisional buses by timers to prevent bus overload.

LPCS and the “C” RHR pump motors do not use timers.

Q. How does a Station Blackout impact the plant and what is the primary concern for it?

A. A station blackout involves a loss of all offsite and emergency onsite (except Div 3) AC power supplies designed to ensure operability of the 4.16 KV ESF buses and control of the reactor following a LOCA. Decay heat removal is the primary concern.

Q. What is the concern of transferring buses with a ground fault present?

A. Every effort should be made to ensure there is no fault on any bus being energized. This prevents personnel injury and possible equipment damage and/or fire.

Q. What is the impact on the RR Pump Seals if all off-site power is lost?

A. All Component Cooling Water Pumps and Control Rod Drive pumps will be lost, thus the RR Pump Seals will no longer have cooling or RD injection. By procedure, The Recirc Pump Auxiliary Seal Injection Pump is used to provide seal injection flow.

Q. What is the impact on not completing DC load shedding in a timely manner during a Station Blackout?

A. The divisional batteries will drain at a more rapid rate. Divisional batteries can supply essential loads, assuming non-essential loads are shed within 1 hours of the SBO, for a period of 4 hours.

Q. How are DC electrical loads impacted on a loss of AC power?

A. The batteries assume the loads normally carried by their respective chargers.

Q. Why is it important to lock out equipment with auto start features prior to restoring power to a bus?

A. When restoring the Busses without placing equipment that can auto start in pull-to-lock, equipment damage can occur due to not having all supporting equipment ready, piping filled & vented, and excessive currents may be drawn with multiple pieces of equipment starting at the same time.

Q. When is required to perform manual Turbine Generator jacking following a loss of AC power?

A. If Bus 1B1 is de-energized and the TG has stopped.

Q. What resources are available to determine which instrumentation or methods are available during a Station Blackout to monitor key plant parameters?

A. Refer to CPS No. 4200.01C003 Monitoring Containment Temperatures During a SBO. Also refer to CPS 4200.01 Appendix B for key instrumentation available depending on the status of AC power available.

Q. What are the guidelines for using RCIC during a Station Blackout for level control?

A. Preferred suction source is Suppression Pool when used for level control. Use of Suppression Pool as a suction is limited to 197°F. Maintain RPV pressure >150 psig, if possible. RCIC operation below 150 psig requires defeating the RCIC Steam Supply Pressure Isolation per CPS 4410.01C001 (as directed by CPS 4200.01).

Q. What is the preferred sequence of system restoration following a loss of AC power when power has been restored to the non-ECCS buses?

A. Restore following plant systems to service. Plant conditions may require a different prioritization than listed.

- 1E/1F BOP batteries/battery chargers (DC)
- Note: Instrument Power from UPS 1A/1B Buses is needed to recover remaining systems.
- Component Cooling Water (CCW)
- Plant Service Water (WS)
- Service and Instrument Air (SA/IA)
- Reactor Water Cleanup (RT): as needed to support RPV forced circ/normal heat sink
- Turbine Building Closed Cooling Water (WT)
- Control Rod Drive Hydraulics (RD)
- Reactor Recirculation (RR): as needed to support RPV forced circ/normal heat sink
- Makeup/Cycled Condensate (MC/CY)
- Plant Chill Water (WO)
- Circulating Water (CW)
- Feedwater/Condensate (FW/CB/CD)
- Turbine and Generator Auxiliaries (TG)
- HVAC systems

Q. How is the risk of Core Damage is effected by assuring HPCS and RCIC availability following a loss of AC power?

A. Core damage risk can be significantly reduced by assuring HPCS and RCIC availability, particularly in the first 30 minutes to one hour of the SBO. A substantial portion of the decay and sensible heat can be removed during this period. HPCS and RCIC availability can be assured by monitoring suppression pool temperature and maintaining RPV water levels. These actions help to ensure that the core remains adequately covered and cooled during a SBO.

Q. What equipment is available to prevent the Main Control Room from exceeding 120°F during a Station Blackout.?

A. Habitability concerns are based on prolonged exposure to > 120°F. At the discretion of the Station ED, supplemental MCR cooling can be initiated utilizing ERO resources per CPS 4200.01C001, MCR Cooling During A SBO. Use of this procedure/equipment is an ERO function, not an on-shift crew function.

Q. Describe the effects of DC load shedding on the restoration of AC power.?

A. DC loading shedding results in the inability to start the D/Gs.

Q. What is the preferred level control system during SBO?

A. HPCS (refer to 4200.01 section for SBO- Level Control Actions).

Q. How are SRVs operated during a SBO?

A. Use non-ADS SRVs first, followed by ADS SRVs in a manner that precludes uneven suppression pool heating, and avoids the running HPCS or RCIC pump suction (refer to 4200.01 section for SBO – Pressure Control actions).

III. REVIEW AND EVALUATION

A. **Summarize the training materials including major changes.**

B. **Ask questions to assess student achievement of objectives.**

C. **Reinforce the relevance, importance, and purpose of the topic.**

D. **Ensure the trainees are aware how the objectives will be evaluated.**