Unplanned Scrams with Complications

Report to the Reactor Oversight Process Working Group
on possible replacement indicator for the
Unplanned Scrams with Loss of Normal Heat Removal
Performance Indicator

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UNPLANNED SCRAMS WITH COMPLICATIONS

1 SUMMARY

Performance indicators (PIs) in combination with baseline inspections are intended to provide a comprehensive risk informed basis for assessing licensee performance. Performance indicators in combination with inspection findings are used by the Nuclear Regulatory Commission (NRC) to establish the appropriate level of oversight. The objective of the initiating events PI is to limit the frequency of those events that upset plant stability and challenge both safety systems and plant operators. Therefore, to provide more comprehensive information the Unplanned Scrams with Complications (USwC) performance indicator is proposed. It will monitor scrams that result in additional complications caused by equipment failures or inappropriate operator actions.

The likelihood of an accident is determined by the frequency of initiating events. The USwC will monitor a subset of those initiating events to allow effective corrective actions due to changes in the frequency of scrams with complications. The USwC PI will be monitored by the performance indicator program and will complement the existing processes used for conducting oversight of plant events.

Variations in plant design contribute to the overall difficulty in developing a simple risk informed indicator to monitor complicated scrams. This fact coupled with the understanding that potentially significant plant events are assessed individually by other NRC processes led to the development of the USwC indicator. A threshold of greater than one complicated scram in the previous 4 quarters was selected as the Green/White threshold (increased regulatory response) for this indicator. This threshold was based on an evaluation of industry performance data (collected during 1995 to 2000) which would result in approximately 5% of the plants exceeding the proposed threshold. No thresholds are provided for the Yellow or Red performance levels because supplemental inspections currently provide an appropriate response, the data available to establish appropriate yellow or red thresholds is exceedingly sparse, and other oversight processes are in place to address abnormally poor performance in this area.

The proposed performance indicator will reflect more current performance information consistent with the annual ROP assessment cycle. A data reporting period of 4 quarters was selected for the PI. This is a shorter monitoring period than the Loss of Normal Heat Removal PI (which is being replaced by the USwC PI) because the reporting criteria for the USwC PI will result in counting more scrams. A 4-quarter data reporting period will also facilitate NRC assessment of licensee performance based on contemporary data. In addition, the green/white threshold has been reduced from three Loss of Normal Heat Removal PI scrams to two USwC PI scrams.

2 INTRODUCTION AND PURPOSE

The original intent of the existing Scrams with Loss of Normal Heat Removal PI was to monitor a subset of unplanned automatic and manual scrams that were complicated by the loss of the normal heat removal path. Such events were believed to provide more challenges to operators during scram recovery and would therefore function as a potential precursor event to more risk-significant scrams. However, because such scrams are uncommon the PI threshold was set at two and would require three scrams in three years to cross the green-white threshold.

Because the Scrams with Loss of Normal Heat Removal PI monitored a limited set of complicated scrams it was determined that it did not adequately reflect complicated scrams that result in operator challenges. In addition, it was realized that a licensee could potentially cross into the white threshold because of a scram that is nearly three years old but that this would not necessarily be reflective of the licensees current level of performance.

Performance indicators do not measure the risk-significance of events. Because a risk-significant event at one plant may not be risk-significant at another and because of the differences among licensees in plant design, procedures, and operator training an industry-wide PI to measure risk-significance would be ineffective. Therefore, the proposed USwC PI was developed to monitor the number of complicated scrams over a short period of time to develop a leading indicator for risk-significant events.

The proposed USwC PI will monitor the following six conditions that have the potential to complicate the operators' scram recovery actions.

1. Reactivity Control
2. Pressure Control (BWRs)/Turbine Trip (PWRs)
3. Power available to Emergency Busses
4. Need to actuate emergency injection sources
5. Availability of Main Feedwater
6. Utilization of scram recovery Emergency Operating Procedures (EOPs)

Since the complicating conditions are not the same for Pressurized Water Reactors (PWRs) versus Boiling Water Reactors (BWRs), a separate flow chart for each type has been developed. If any of the conditions in the appropriate flow chart are met the licensee must report a "hit" for the PI.

3 PROPOSED REPLACEMENT INDICATOR

Unplanned Scrams with Complications (USwC)

Purpose

This indicator monitors that subset of unplanned automatic and manual scrams that require additional operator actions beyond that of the "normal" scram. Such events or conditions have the potential to present additional challenges to the plant operations staff and therefore may be more risk-significant than uncomplicated scrams.

Indicator Definition

The USwC indicator is defined as the number of unplanned scrams while critical, both manual and automatic, during the previous 4 quarters that require additional operator actions as determined by the appropriate flowchart.

Data Reporting Elements

The following data are required to be reported for each reactor unit.

- The number of unplanned automatic and manual scrams while critical in the previous quarter that required additional operator response as determined by the flowchart criteria.

Calculation

The indicator is determined using the values reported for the previous 4 quarters as follows:

value = total unplanned scrams while critical in the previous 4 quarters that required additional operator response as determined by the flowchart criteria.

Definition of Terms

Scram means the shutdown of the reactor by the rapid addition of negative reactivity by any means, e.g., insertion of control rods, boron, use of diverse scram switch, or opening reactor trip breakers. Reactor Scram and Reactor Trip have the same meaning. The terms are both used in this document.

Unplanned scram means that the scram was not an intentional part of a planned evolution or test as directed by a normal operating or test procedure. This includes scrams that occurred during the execution of procedures or evolutions in which there was a high chance of a scram occurring but the scram was neither planned nor intended.

Criticality, for the purposes of this indicator, typically exists when a licensed reactor operator declares the reactor critical. There may be instances where a transient initiates from a subcritical condition and is terminated by a scram after the reactor is critical—this condition would count as a scram.

Clarifying Notes

This indicator is a subset of the IE01 indicator “Unplanned Scrams” and to be considered in this indicator the scram must have counted in IE01.

PWR Flowchart Questions

Did two or more control rods fail to fully insert?

Did control rods that are required to move on a reactor trip fail to fully insert into the core as evidenced by the Emergency Operating Procedure (EOP) evaluation criteria? As an example for some PWRs using rod bottom light indications, if more than one-rod bottom light is not illuminated, this question must be answered "Yes." The basis of this step is to determine if additional actions are required by the operators as a result of the failure of all rods to insert. Additional actions, such as emergency boration, pose a complication beyond the normal scram response that this metric is attempting the measure. It is allowable to have one control rod not fully inserted since core protection design accounts for one control rod remaining fully withdrawn from the core on a reactor trip. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted. During performance of this step of the EOP the licensee staff would not need to apply the “Response Not Obtained” actions. Other means not specified in the EOPs are not allowed for this metric.

Did the turbine fail to trip?

Did the turbine fail to trip automatically/manually as required on the reactor trip signal? To be a successful trip, steam flow to the main turbine must have been isolated by the turbine trip logic actuated by the reactor trip signal, or by operator action from a single switch or pushbutton. The allowance of operator action to trip the turbine is based on the operation of the turbine trip logic from the operator action if directed by the EOP. Operator action to close valves or secure pumps to trip the turbine beyond use of a single turbine trip switch would count in this indicator as a failure to trip and a complication beyond the normal reactor trip response. Trips that occur prior to the turbine being placed in service or “latched” should have this question answered as “No”.

Was power lost to any ESF bus?

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF (Emergency Safeguards Features) bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or

- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes.

Was a Safety Injection signal received?

Was a Safety Injection signal generated either manually or automatically during the reactor trip response? The question's purpose is to determine if the operator had to respond to an abnormal condition that required a safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged Reactor Coolant System (RCS) inventory, pressure, or temperature severely enough to require a safety injection. A severe steam generator tube leak that would require a manual reactor trip because it was beyond the capacity of the normal at power running charging system should be counted even if a safety injection was not used since additional charging pumps would be required to be started.

Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of "not recoverable using approved plant procedures" will allow a licensee to answer "No" to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-proceduralized operating alignments require an answer of "Yes." Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater this question should be answered as "No".

Was the scram response procedure unable to be completed without entering another EOP?

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step

is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

BWR Flowchart Questions

Did an RPS actuation fail to indicate / establish a shutdown rod pattern for a cold clean core?

Withdrawn control rods are required to be inserted to ensure the reactor will remain shutdown under all conditions without boron to ensure the reactor will have the required shutdown margin in a cold, xenon-free state.

Any initial evaluation that calls into question the shutdown condition of the reactor requires this question to be answered "Yes." Required entry into the Anticipated Transient Without Scram (ATWS) leg of the EOP or required use of Alternate Rod Insertion (ARI) call for this question to be answered "Yes." Failure of the rod position indication coupled with the loss of full-in-lights on enough rods to question the cold clean core shutdown status would require this question to be answered "Yes."

The basis of this step is to determine if additional actions are required by the operators to ensure the plant remains shutdown as a result of the failure of any rods to insert (or indicate inserted). Additional actions, such as boron injection, or other actions to insert control rods to maintain shutdown, pose a complication beyond the normal scram response that this metric is attempting the measure. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted.

Was pressure control unable to be established following the initial transient?

To be successful, reactor pressure must be controlled following the initial transient without the automatic use of Safety Relief Valves (SRVs) to receive a "No" response. Automatic cycling of the SRV(s) that may have occurred as a result of the initial transient would result in a "No" response, but automatic cycling of the SRV(s) subsequent to the initial transient would result in a "Yes" response. Additionally the SRV(s) cannot fail open. The failure of the pressure control system (i.e. turbine valves / turbine bypass valves / HPCI / RCIC/isolation condenser) to maintain the reactor pressure or a failed open SRV(s) count in this indicator as a complication beyond the normal reactor trip response and would result in a yes answer.

Was power lost to any Class 1E Emergency / ESF bus?

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric.

This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or
- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes. Plants with a dedicated High Pressure Core Spray (HPCS) bus do not count the HPCS ESF bus in this PI.

Was a Level 1 Injection signal received?

Was a Level 1 Injection signal generated either manually or automatically during the reactor scram response? The consideration here is if the operator had to respond to abnormal conditions that required a low pressure safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged RCS inventory, or Drywell pressure severely enough to require a safety injection. Plants that do not have a high pressure Emergency Core Cooling System (ECCS) level signal that is different than the low pressure ECCS level signal would ask “was low pressure injection required?”

Was Main Feedwater not available or not recoverable using approved plant procedures?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “NO” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Feedwater must be capable of feeding the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

Following initial transient, did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?

This step is used to determine if the scram was uncomplicated and did not require using other procedures beyond the normal scram response. Following the initial transient, maintaining the reactor and drywell pressures below the Emergency Procedure entry values while ensuring reactor level is above the Emergency Procedure entry values allows answering ”No.” The requirement to remain in the EOPs because of reactor pressure/level and drywell pressure following the initial transient indicates complications beyond the typical reactor scram. Additionally, repeated level scram signals during the initial transient indicate level could not be stabilized and required this question be answered “Yes”.

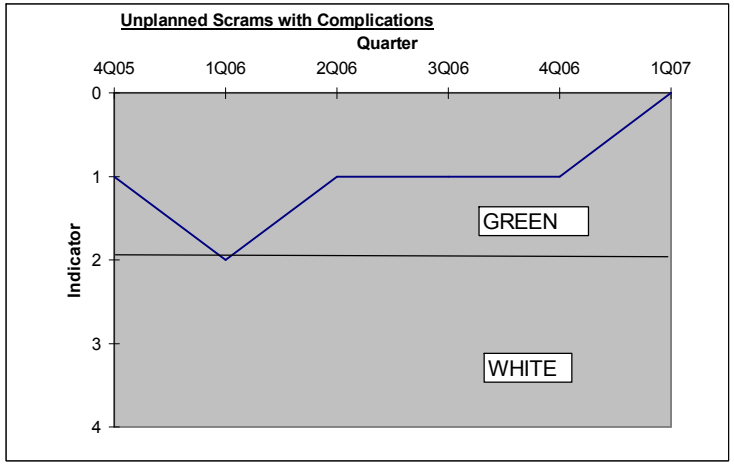
Table 1 – PERFORMANCE INDICATORS				
Cornerstone	**Indicator**	**Thresholds**		
		Increased Regulatory Response Band	**Required Regulatory Response Band**	**Unacceptable Performance Band**
Initiating Events	**IE04** Unplanned Scrams with Complications	2 or more	N/A	N/A

3.1.1.1 Data Examples

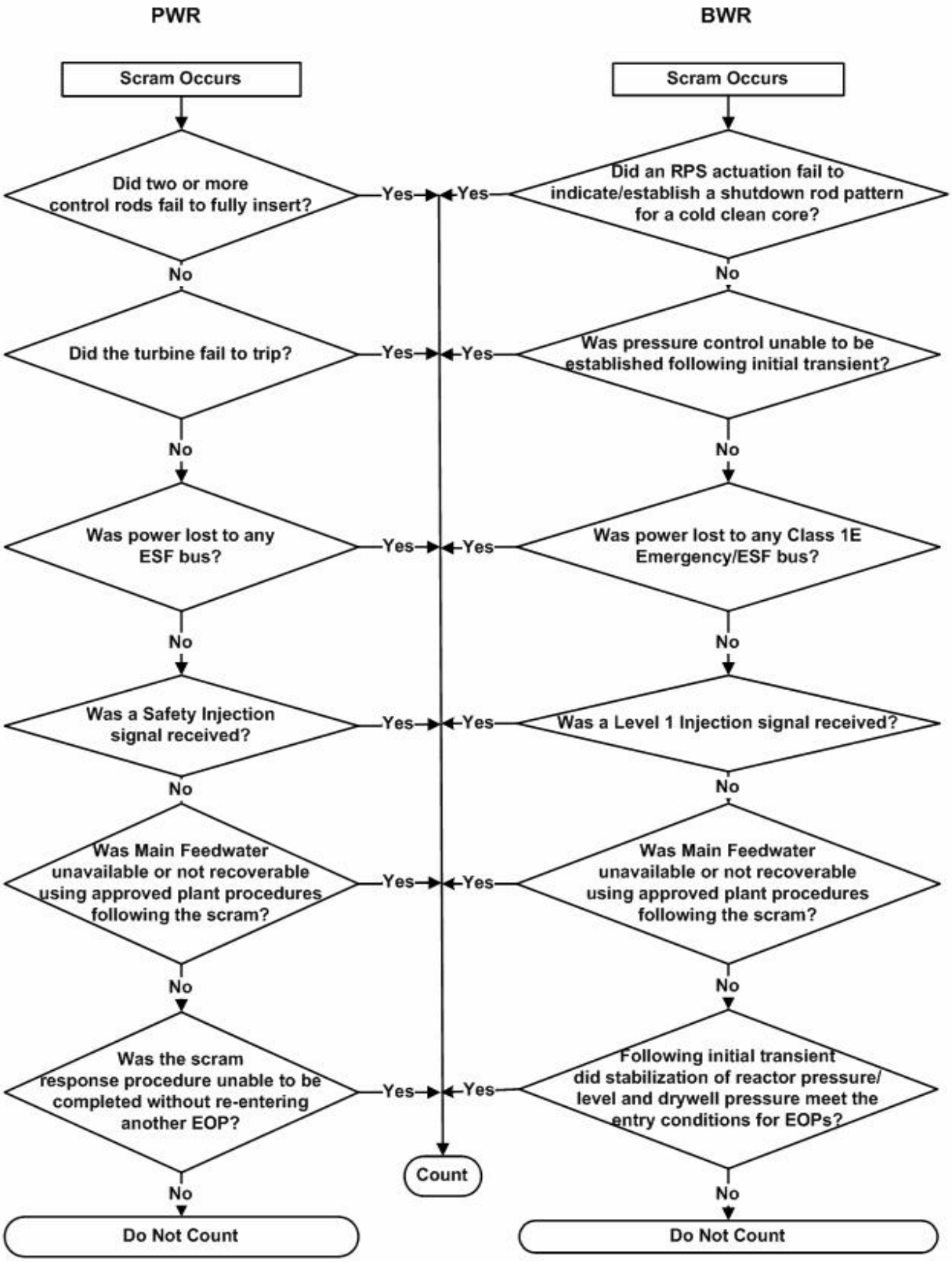
Unplanned Scrams with Complications

	1Q05	2Q05	3Q05	4Q05	1Q06	2Q06	3Q06	4Q06	1Q07
# of Scrams with complications	0	1	0	0	1	0	0	0	0
in prev qtr									
Total over 4 quarters				1	2	1	1	1	0
Indicator value				1	2	1	1	1	0

Thresholds	
Green	0 or 1
White	2 or more
Yellow	N/A
Red	N/A



IE04 Unplanned Scrams with Complications - Flowchart



4 SUPPORTING BASIS FOR PROPOSED INDICATOR

4.1 PWR FLOWCHART QUESTIONS

4.1.1 PWR Flowchart Basis Discussion

1. <u>Did two or more control rods fail to fully insert?</u>

Did control rods that are required to move on a reactor trip fully insert into the core as evidenced by the Emergency Operating Procedure (EOP) evaluation criteria? As an example for some PWRs using rod bottom light indications, if more than one-rod bottom light is not illuminated, this question must be answered "Yes." The basis of this step is to determine if additional actions are required by the operators as a result of the failure of all rods to insert. Additional actions, such as emergency boration, pose a complication beyond the normal scram response that this metric is attempting the measure. It is allowable to have one control rod not fully inserted since core protection design accounts for one control rod remaining fully withdrawn from the core on a reactor trip. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted. During performance of this step of the EOP the licensee staff would not need to apply the “Response Not Obtained” actions. Other means not specified in the EOPs are not allowed for this metric.

<u>Basis Discussion</u>

This question is designed to verify that the Reactor did actually trip. As long as a plant uses the EOP questions to verify that the reactor tripped without entering a “response not obtained” or “contingency actions” requirement this question should be answered as “No”. Some specific examples from plant EOPs are provided below.

Some CE plant EOPs use the following checks:

- Check that reactor power is dropping.
- Check that start-up rate is negative.
- Check that no more than one full strength CEA is **NOT** inserted.

If the operations staff determines that one of these questions is not satisfied then they must perform a contingency action. The requirement to perform that contingency action would be considered as a complication for the Unplanned Scrams with Complications metric.

Some Westinghouse plant EOPs verify the following items:

- Verify Reactor Trip
    - Rod bottom lights – LIT
    - Reactor trip and bypass breakers – OPEN
    - Neutron flux - LOWERING

If the operations staff determines that one of these questions is not satisfied then they must perform a response not obtained action. The requirement to perform that

contingency action would be considered as a complication for the Unplanned Scrams with Complications metric. There is an exception in this question for Westinghouse plants using the question structure given in this example. A single rod bottom light not lit would be acceptable in the Unplanned Scrams with Complications metric even though it would require a response not obtained action. This exception is allowed to make the metric consistent between vendor procedures, also the reactor analysis allows for the single most reactive control rod to be stuck in the full out position.

Some B&W plants EOPs verify the following:

- Verify Alternate Rod Insertion and reactor power dropping

If the operations staff determines that this question is not satisfied then they must perform a contingency action. The requirement to perform that contingency action would be considered as a complication for the Unplanned Scrams with Complications metric. There is an exception in this question for B & W plants using the question structure given in this example. A single rod not fully inserted would be acceptable in the Unplanned Scrams with Complications metric even though it would require a contingency action. This exception is allowed to make the metric consistent between vendor procedures, also the reactor analysis allows for the single most reactive control rod to be stack in the full out position

2. <u>Did the turbine fail to trip?</u>

Did the turbine fail to trip automatically/manually as required on the reactor trip signal? To be a successful trip, steam flow to the main turbine must have been isolated by the turbine trip logic actuated by the reactor trip signal, or by operator action from a single switch or pushbutton. The allowance of operator action to trip the turbine is based on the operation of the turbine trip logic from the operator action if directed by the EOP. Operator action to close valves or secure pumps to trip the turbine beyond use of a single turbine trip switch would count in this indicator as a failure to trip and a complication beyond the normal reactor trip response. Trips that occur prior to the turbine being placed in service or "latched" should have this question answered as "No".

<u>Basis Discussion</u>

This question is designed to verify that the Turbine did actually trip. As long as a plant uses the EOP questions to verify that the turbine tripped without entering a "response not obtained" or "contingency actions" requirement this question should be answered as "No". There is one exemption to this step that allows an Operator to use the manual turbine trip handswitch/pushbutton as an acceptable alternative. The simplicity of the action and the fact that Operators are specifically trained on this action provide the basis for this exception. It is NOT an acceptable alternative for the Operators to close individual governor or throttle valves, main steam isolation valves, or secure hydraulic control pumps. The failure of a generator output breaker to trip with the turbine is considered as a complication. Any actions beyond the use of one handswitch/pushbutton would need to be considered as a complication for this question. For reactor trips that occur prior to the turbine being placed in service or "latched" this specific question should be answered as "No" since the turbine is already tripped. Some specific examples from plant EOPs are provided below:

Some CE plant EOPs use the following checks:

- **Check that the main turbine is tripped**
- **Check that the main generator output breakers are open**

The use of the contingency action to manually trip the turbine is an acceptable alternative. Performance of any other contingency actions would require answering this question as "Yes".

Some Westinghouse plant EOPs verify the following items:

- **Verify all turbine throttle valves – CLOSED**
- **Main generator output breaker - OPEN**

The use of the contingency action to manually trip the turbine is an acceptable alternative. Performance of any other response not obtained actions would require answering this question as "Yes".

Some B&W plant EOPs verify the following:

- **Verify turbine throttle and governor valve closed**

The use of the contingency action to manually trip the turbine is an acceptable alternative. Performance of any other contingency actions would require answering this question as "Yes".

3. <u>Was power lost to any ESF bus?</u>

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or
- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes.

Basis Discussion

Most EOP versions check that power is available in response to the reactor trip. This question is designed to verify that electric power was available after the reactor trip. As long as a plant uses the EOP questions to verify that power was available without entering a "response not obtained" or "contingency actions" requirement this question should be answered as "No". There is an exemption to this step that allows an Operator to manually restore power within 10 minutes as an acceptable alternative. The exception is limited to those actions necessary to close a breaker from the main control board. Actions requiring access to the back of the control boards or any other remote location would require answering this question as "Yes". It is acceptable to manipulate more than one switch, such as a sync switch, in the process of restoring power to the bus. It is acceptable to close more than one breaker. It is acceptable to restore power from the emergency AC source, such as diesel generators, or from off-site power. This exception is allowed since most EOPs are configured to check that power is available to at least one of the safety busses which will satisfy plant safety concerns. If power is not available to at least one safety bus most EOPs will direct transition to another EOP to mitigate this condition. The additional operator action to restore power to additional busses has been discussed and considered acceptable as long as it can be completed within the time limitations of 10 minutes (chosen to limit the complexity) and the constraints of switch operation from the main control board. Any actions beyond these would need to be considered as a complication for this question. Because of the wide variation in power distribution designs, voltage, and nomenclature across the PWR fleet, no specific EOP examples are given here.

4. Was a Safety Injection signal received?

Was a Safety Injection signal generated either manually or automatically during the reactor trip response? The questions purpose is to determine if the operator had to respond to an abnormal condition that required a safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged Reactor Coolant System (RCS) inventory, pressure, or temperature severely enough to require a safety injection. A severe steam generator tube leak that would require a manual reactor trip because it was beyond the capacity of the normal at power running charging system should be counted even if a safety injection was not used since additional charging pumps would be required to be started.

Basis Discussion

This question is designed to verify that the plant conditions are stable and do not require the actuation of the emergency injection system (safety injection for Westinghouse plants, SIAS for CE). Plant conditions that result from a loss of inventory or loss of pressure control in the RCS or Steam Generator (SG) would likely require actuation of the emergency injection systems and would be considered a complication. Conversely, plant conditions following the reactor trip that do not result in a safety injection actuation would not be considered as complications. An exception to this is the existence of a severe steam generator tube leak. In those limited circumstances where a steam generator tube leak exists that is severe enough to require a reactor trip but can be controlled by starting additional inventory control pumps that are not normally running during normal power

operations without initiating a safety injection signal should result in a "Yes" answer and considered as a complication. A small steam generator tube leak where inventory can be maintained using the already running inventory control pumps would NOT be considered as complicated even if the reactor was tripped. Those instances where a safety injection was not required by actual plants conditions but occurred due to operator error, spurious actuations, or set-point error should be considered as complications and this question answered as "Yes".

5. **Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?**

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of "not recoverable using approved plant procedures" will allow a licensee to answer "No" to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-proceduralized operating alignments require an answer of "Yes." Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater this question should be answered as "No".

Basis Discussion

This section of the indicator is a holdover from the Scrams with Loss of Normal Heat Removal indicator which the USwC indicator is replacing. Since all PWR designs have an emergency Feedwater system that operates if necessary, the availability of the normal or main Feedwater systems is a backup in emergency situations. This portion of the indicator is designed to measure that backup availability directed by the EOPs on a loss of all emergency Feedwater.

It is not necessary for the main Feedwater system to continue operating following a reactor trip. The system must be free from damage or failure that would prohibit restart of the system if necessary. Since some plant designs do not include electric driven main Feedwater pumps (steam driven pumps only) it may not be possible to restart main Feedwater pumps without a critical reactor. Those plants should answer this question as "No" and move on. Some other designs have interlocks in place to prevent feeding the steam generators with main Feedwater unless reactor coolant temperature is greater than

the no-load average temperature. These plants should also answer this question as "No" and move on.

Licensees should rely on the material condition availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps and may be lower than normal if procedures allow pump operation at that lower value. As long as these support systems are able to be restarted (if not running) to support main feedwater restart within the 30 minute timeframe they can be considered as available. These requirements apply until the completion or exit of the scram response procedure.

The availability of steam dumps to the condenser does NOT enter into this indicator at all. Use of atmospheric steam dumps following the reactor trip is acceptable for any duration.

Loss of one feed pump does not cause a loss of main feedwater. Only one is needed to remove residual heat after a trip. As long as at least one pump can still operate and provide Feedwater to the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, main feedwater should be considered available.

The failure in a closed position of a feedwater isolation valve to a steam generator is a loss of feed to that one steam generator. As long as the main feedwater system is able to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria, the loss of ability to feed other steam generators should not be considered a loss of feedwater. Isolation of the feedwater regulating or isolation valves does not constitute a loss of feedwater if nothing prevents them from being reopened in accordance with procedures.

A Steam Generator Isolation Signal or Feedwater Isolation Signal does not constitute a loss of main feedwater as long as it can be cleared and feedwater restarted. If the isolation signal was caused by a high steam generator level, the 30 minute estimate for restart time frame should start once the high level isolation signal has cleared.

The 30 minute time frame for restart of main Feedwater was chosen based on restarting from a hot and filled condition. Since this time frame will not be measured directly it should be an estimation developed based on the material condition of the plants systems following the reactor trip. If no abnormal material conditions exist the 30 minutes should be met. If plant procedures and design would require more than 30 minutes even if all systems were hot and the material condition of the plants systems following the reactor trip were normal, that routine time should be used in the evaluation of this question, provided SG dry-out cannot occur on an uncomplicated trip if the time is longer than 30 minutes. The opinion of the on-shift licensed SRO during the reactor trip should be accepted in determining if this timeframe was met.

6. <u>Was the scram response procedure unable to be completed without entering another EOP?</u>

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the

normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

Basis Discussion

When a scram occurs plant operators enter the EOPs to respond to the condition. In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available, and reactor coolant pressures and temperatures are at expected values and controlled. Once these verifications are done and the plant conditions are considered "stable" operators may exit the initial procedure to another procedure that will stabilize and prepare the remainder of the plant for transition to the normal operating procedures. The plant could then be maintained in Hot Standby, to perform a controlled normal cool down, or to begin the restart process. The criteria in this question is used to verify there were no other conditions that developed during the stabilization of the plant in the scram response that required re-entry into the EOPs or transition to a follow on EOP.

There are some EOPs that are used specifically at the operator discretion and are not required to be used. In the Westinghouse EOP suite these are Yellow Path functional restoration procedures and the re-diagnosis procedures. These procedures typically verify that the operator is taking the correct action (re-diagnosis) or the stabilization of some minor plant parameters (Yellow path). Use of these procedures is an allowed exception to this step. The transition out of these procedures to an EOP different from the current procedure in effect, i.e. a new procedure or the base procedure, would count as a complication.

4.1.2 PWR Case Study 1

Event Description: the below is an actual LER event description.

At approximately 100% steady state reactor power, Control Room operators initiated a manual reactor trip as a result of indications that multiple Control Rods (CRs) had dropped into the reactor core. All Reactor Trip (RT) breakers opened but all rod bottom lights did not illuminate. Rod Cluster Control Assemblies (RCCA) L7, J13, F6, F10, K10, C5, and C13 were not considered fully inserted because the rod bottom lights for these RCCAs did not illuminate. The Plant Information Computer System indicated all RCCAs were fully inserted. In accordance with plant procedures, operators re-initiated a manual RT. Operations verified the reactor was tripped and all RCCAs were fully inserted.

Prior to the event all CRs were withdrawn from the reactor core and in Automatic, both Main Boiler Feedwater Pumps (MBFPs) were in service, the Auxiliary Feedwater Pumps (AFWPs) were in standby, the EDGs were in standby, and off-site power was in service. At 1435 hours, indicated reactor power decreased from approximately 99.87% to 50% (based on the Nuclear Instrumentation System power range neutron flux monitors) as a result of 12 CRs dropping into the core. Of the twelve CRs that dropped into the core, four (4) CRs (M-12, M-4, D-12, and D-4) went from 223 steps to 150 steps out and eight (8) control rods (N-13, L-13, N-5, N-3, E-3, C-3,

C13, and C-11) went from 223 steps out to 0 steps. Reactivity control is achieved by a combination of 53 CRs [29 RCCAs are in control banks (CB) and 24 in shutdown banks (SDBs)] and chemical shim (boric acid). The CRs are divided into 1) a shutdown (SD) group comprised of two SDBs of eight rod clusters each and two SDBs of four rod clusters each, and 2) a control group comprised of four CBs containing eight, four, eight, and nine rod clusters.

After the manual RT, seven (7) rod bottom lights for CR SDB A, Rod L7, SDB 3, Rod J12, SDB D, Rods F6, F10, K10, CB A, Rod C5, and CB C, Rod C13 did not illuminate. All other reactivity indications were normal. As a result of the manual RT, the Main Turbine-Generator tripped, and the AFWPs automatically started. The EDGs did not start as off-site power remained in service. An alarm for low pressurizer pressure annunciated as a result of a reduction of the RCS pressure to the normal trip setpoint (1985 psig). The decrease in pressure was due to the negative reactivity from the initial rod insertion. All primary safety systems functioned properly. Unexpected responses included: both MBFP suction relief valves lifted (reset at approximately 1458 hours), a "Not in Sync" alarm was received for the 24 Static Inverter (adjusted and cleared), and a low oil level alarm on upper reservoir was received for the 23 Reactor Coolant Pump (RCP). Power for the rod control system is distributed to five power cabinets from two motor-generator sets connected in parallel through two series of Reactor Trip Breakers (RTBs). The ac power distribution lines downstream of the RTBs are routed above the power cabinets through a fully enclosed three-phase, four wire plug-in, bus duct assembly.

The ac power to each cabinet is carried by the bus duct assembly through three plug-in fused disconnect switches for the stationary, movable and lift coil circuits of the mechanisms associated with that cabinet. During the investigation of the event the disconnect switch (JSI on top of rod control power cabinet (CAB) IAC was discovered to be open. Opening the disconnect switch caused loss of power to the stationary coils for twelve (12) CRs. The switch that was placed in the open position was for power cabinet IAC which controls the rods for CB A, Group 1, CB C, Group 1, and SDB A, Group 1. Loss of power to these CRs caused the rods to drop into the reactor core per design. Four (4) CRs partially inserted (223 steps in to 150 steps). CR power cabinet (IAC) disconnect switch was inadvertently bumped open by a contractor erecting scaffolding around the CR power cabinets in the cable spreading room of the Control Building (NA). The disconnect switch to rod control power cabinet IAC was re-closed. An assessment of the condition by reactor engineering concluded that power was removed from the CR stationary gripper coils when the disconnect switch was opened. When no motion is demanded and rods are stationary, current is sent to the coils, which keeps the grippers engaged on the CR. The CR system sensed the power loss condition and transmitted a high current order to the movable gripper coils which had not lost their power. The movable gripper coils were able to catch four of the CRs as they were falling but did not catch the remaining CRs in the other CR groups. The cause of the failure of seven (7) rod bottom lights to illuminate after the dropped rod event was due to failed light bistables.

In answering the questions for this indicator, some additional information beyond that gathered for the LER will be required. In this case the usage history of the EOPs will be required. For this example consider that there were no additional EOPs used beyond the normal procedures.

1. **<u>Did two or more control rods fail to fully insert?</u>**

   Did control rods that are required to move on a reactor trip fully insert into the core as evidenced by the Emergency Operating Procedure (EOP) evaluation criteria? As an example for some PWRs using rod bottom light indications, if more than one-rod bottom

light is not illuminated, this question must be answered "Yes." The basis of this step is to determine if additional actions are required by the operators as a result of the failure of all rods to insert. Additional actions, such as emergency boration, pose a complication beyond the normal scram response that this metric is attempting the measure. It is allowable to have one control rod not fully inserted since core protection design accounts for one control rod remaining fully withdrawn from the core on a reactor trip. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted. During performance of this step of the EOP the licensee staff would not need to apply the "Response Not Obtained" actions. Other means not specified in the EOPs are not allowed for this metric.

Answer:

YES. This question should be answered as "YES" and the trip counted as a Scram with Complications since the rod bottom lights did not indicate fully inserted control rods. If the EOP allows the use of the plant computer indications instead of rod bottom lights this question should be answered as "NO." To qualify the plant computer indication must not be considered as a "Response Not Obtained" step but rather as a listed normal indication.

2. Did the turbine fail to trip?

Did the turbine fail to trip automatically/manually as required on the reactor trip signal? To be a successful trip, steam flow to the main turbine must have been isolated by the turbine trip logic actuated by the reactor trip signal, or by operator action from a single switch or pushbutton. The allowance of operator action to trip the turbine is based on the operation of the turbine trip logic from the operator action if directed by the EOP. Operator action to close valves or secure pumps to trip the turbine beyond use of a single turbine trip switch would count in this indicator as a failure to trip and a complication beyond the normal reactor trip response. Trips that occur prior to the turbine being placed in service or "latched" should have this question answered as "No".

Answer:

NO. The turbine tripped per design,

3. Was power lost to any ESF bus?

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or

- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes.

Answer:

NO. Emergency diesels were not required to start. Offsite power remained available throughout the trip response. All ESF busses remained energized throughout the trip response.

4. Was a Safety Injection signal received?

Was a Safety Injection signal generated either manually or automatically during the reactor trip response? The questions purpose is to determine if the operator had to respond to an abnormal condition that required a safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged Reactor Coolant System (RCS) inventory, pressure, or temperature severely enough to require a safety injection. A severe steam generator tube leak that would require a manual reactor trip because it was beyond the capacity of the normal at power running charging system should be counted even if a safety injection was not used since additional charging pumps would be required to be started.

Answer:

NO. No SI signal was required or received.

5. Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “No” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-

proceduralized operating alignments require an answer of "Yes." Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater this question should be answered as "No".

Answer:

NO. Main feedwater pumps were available and the feedwater system could have been operated to supply feedwater to all steam generators.

6. Was the scram response procedure unable to be completed without entering another EOP?

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

Answer:

NO. The reactor trip response procedures were completed without re-entering another EOP.

PWR Case Study 2

Event Description: the below is an actual LER event description.

At 100% steady state reactor power, Operators manually tripped the reactor as a result of oscillating Feedwater (FW) flow and SG level with flow perturbations and FW pipe movement in the Auxiliary FW (AFW) Pump Building. Prior to the transient, while operating at 100% reactor power, with SG level control in AUTO, 22 SG Narrow Range (NR) level records show two cycles of level changes of approximately 2% and correction in automatic with no operator action. Subsequently, operators observed 22 SG NR level starting to decrease from a normal value of 49% to 30% with a deviation alarm annunciating at 44%. CR operators observed oscillating FW flow and erratic behavior of the 22 Main FW regulating valve FCV-427. Operators entered Abnormal Operating Procedure 2AOP-FW-1 and placed the FW regulating valve (FCV-427) in manual and attempted to increase FW flow in 22 SG without success. Excessive FW flow oscillations continued. Operators then opened low flow bypass valve FCV-427L to increase SG level which started 22 SG level increasing at a level of 30%. At approximately 35% SG level valve FCV- 427L was returned to closed. A Nuclear Plant Operator (NPO) in the AFW Pump Building reported to the control room loud noises due to flow perturbations and pipe movement. Based on plant conditions, the Control Room Supervisor (CRS) directed a manual reactor trip. All control rods fully inserted and all primary systems functioned properly. The 22 FW regulating valve FCV-427 failed to fully close. Operators initiated FW isolation by closing FW motor operated isolation valves (MOV) BFD-5-1 and BFD-90-1. A 22 SG high level trip was actuated at 73% SG level, initiating automatic closure of the Main FW Pump motor operated discharge valves (BFD-2-21 and BFD-2-22), Main FW and Low Flow FW regulating and isolation valves, and trip of the turbine driven Main FW Pumps. The plant was stabilized in hot standby with decay heat being removed by the main condenser. Offsite power remained available and therefore the EDGs did not start. The AFW System automatically started as a result of a SG low level normally experienced on trips from full power. FW regulating valve FCV-427 is a Copes-Vulcan globe valve with Copes-Vulcan actuator Model D-1000-160. The valve has a positioner to perform its modulating function and 3 solenoids attached to the actuator for fast closure. CR operators observed the rod bottom lights, RT First Out Annunciator (Manual Trip). The plant was stabilized in hot standby with decay heat being released to the main condenser through the steam dump valves. A post transient evaluation was performed. A non-intrusive inspection was performed of the remaining FW regulating valves (FCV-417, FCV-437, FCV-447) to verify that their valve cages had not unthreaded from the valve body webs. The verification was done by obtaining the maximum stroke capability of the FCVs and relating that to a point at which the valve stem is connected into the actuator yoke (Measurements of the FCVs exposed stem threads and actuator posts were compared to the available actuator travel). These measurements provided reasonable assurance that the remaining FCV cages were properly threaded into their body webs. Following plant shutdown a walk down was performed of the four (4) FW lines inside containment and FW and AFW piping outside containment for any impacts of the FW flow perturbations. There were no indications of excessive movement or damage to the insulation, supports or piping above the 95 foot elevation of containment nor was there any observed signs of excessive movements, support damage, support impacts/scarring, or insulation damage on FW lines to SG-21, SG-22, SG-23, SG-24 on any containment elevations. For FW and AFW piping outside containment, no piping or support damage was evident due to pipe movements from the flow perturbations. FW piping inside and outside containment showed some light powder insulation dust on the floor indicative of pipe vibration.

In answering the questions for this indicator, some additional information beyond that gathered for the LER will be required. In this case the usage history of the EOPs will be required. For this example consider that there were no additional EOPs used beyond the normal procedures.

1. **Did two or more control rods fail to fully insert?**

   Did control rods that are required to move on a reactor trip fully insert into the core as evidenced by the Emergency Operating Procedure (EOP) evaluation criteria? As an example for some PWRs using rod bottom light indications, if more than one-rod bottom light is not illuminated, this question must be answered "Yes." The basis of this step is to determine if additional actions are required by the operators as a result of the failure of all rods to insert. Additional actions, such as emergency boration, pose a complication beyond the normal scram response that this metric is attempting the measure. It is allowable to have one control rod not fully inserted since core protection design accounts for one control rod remaining fully withdrawn from the core on a reactor trip. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted. During performance of this step of the EOP the licensee staff would not need to apply the “Response Not Obtained” actions. Other means not specified in the EOPs are not allowed for this metric.

   Answer:

   NO. All control rods fully inserted as indicated by the rod bottom lights.

2. **Did the turbine fail to trip?**

   Did the turbine fail to trip automatically/manually as required on the reactor trip signal? To be a successful trip, steam flow to the main turbine must have been isolated by the turbine trip logic actuated by the reactor trip signal, or by operator action from a single switch or pushbutton. The allowance of operator action to trip the turbine is based on the operation of the turbine trip logic from the operator action if directed by the EOP. Operator action to close valves or secure pumps to trip the turbine beyond use of a single turbine trip switch would count in this indicator as a failure to trip and a complication beyond the normal reactor trip response. Trips that occur prior to the turbine being placed in service or “latched” should have this question answered as “No”.

   Answer:

   NO. The turbine tripped per design,

3. **Was power lost to any ESF bus?**

   During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or
- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes.

Answer:

NO. Emergency diesels were not required to start. Offsite power remained available throughout the trip response. All ESF busses remained energized throughout the trip response.

4. Was a Safety Injection signal received?

Was a Safety Injection signal generated either manually or automatically during the reactor trip response? The questions purpose is to determine if the operator had to respond to an abnormal condition that required a safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged Reactor Coolant System (RCS) inventory, pressure, or temperature severely enough to require a safety injection. A severe steam generator tube leak that would require a manual reactor trip because it was beyond the capacity of the normal at power running charging system should be counted even if a safety injection was not used since additional charging pumps would be required to be started.

Answer:

NO. No SI signal was required or received.

5. Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “No” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-

proceduralized operating alignments require an answer of "Yes." Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater this question should be answered as "No".

Answer:

NO. Main FW was the cause of the manual reactor trip: one of four feed regulating valves (FRV-447) was unavailable for FW addition to SGs. FW pumps were available to be restarted and three FW loops could have been operated to supply FW to 3 of 4 SGs.

6. Was the scram response procedure unable to be completed without entering another EOP?

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

Answer:

NO. The reactor trip response procedures were completed without re-entering another EOP.

PWR Case Study 3

Event Description: the below is an actual LER event description.

An automatic reactor trip was initiated due to a low reactor coolant flow condition following a trip of the 'B' Reactor Coolant Pump (RCP) motor. The RCP trip was initiated by a current imbalance sensed by the motor's protective relay. The current imbalance was a result of a transmission system disturbance. At the time of the event, the plant was operating in Mode 1 (Hot Full Power) at 100 percent power. The system disturbance was initiated by a transmission line fault within a neighboring electric cooperative's transmission system. Due to a defective electrical connection within the electric cooperative's protective relaying scheme, the transmission line breakers protecting the affected line did not receive a trip signal to clear the fault. Since the breaker failure relaying scheme utilized the same circuitry containing the defective electrical connection, breaker failure logic was not initiated to trip the next breakers upstream of the transmission line fault. In addition, there was no redundant line relaying or local backup relaying on the substation transformer. As a result, the fault was not properly cleared from the electric cooperative's transmission system. For approximately the next eight minutes, multiple subsequent faults were introduced onto the system as the transmission line incurred damage and fell to the ground over an approximate distance of six miles. Ultimately, the fault condition was cleared following the failure of the distribution system transformer supplying the faulted transmission line. Approximately one minute into the event, the "B" RCP tripped due to a motor current imbalance, which resulted from the transmission system disturbance. The automatic reactor trip was initiated for a low reactor coolant flow condition due to the RCP trip. Shortly after the reactor trip, the three remaining RCPs and all main condenser circulating water pumps also tripped because of motor current imbalance. Due to the tripping of all RCPs, the pressurizer spray system was unavailable. Additionally, the tripping of all main condenser circulating water pumps affected the ability to use the main condenser as a heat sink. This resulted in reliance on the atmospheric steam dumps causing reactor coolant system average temperature (RCS Tavg) to increase from 557 to 562 degrees F. The combination of establishing natural circulation due to the loss of all RCPs and increasing RCS Tavg, caused a pressurizer in-surge raising RCS pressure to the pressurizer power-operated relief valve (PORV) set point. Prior to re-establishing the pressurizer spray system, both PORVs momentarily lifted once, relieving RCS pressure to the pressurizer relief tank. RCPs were restored approximately 32 minutes after initiation of the event. During this entire event, all safety-related and non safety-related systems and components functioned in accordance with design.

In answering the questions for this indicator, some additional information beyond that gathered for the LER will be required. In this case the usage history of the EOPs will be required. For this example consider that there were no additional EOPs used beyond the normal procedures.

1. Did two or more control rods fail to fully insert?

Did control rods that are required to move on a reactor trip fully insert into the core as evidenced by the Emergency Operating Procedure (EOP) evaluation criteria? As an example for some PWRs using rod bottom light indications, if more than one-rod bottom light is not illuminated, this question must be answered "Yes." The basis of this step is to determine if additional actions are required by the operators as a result of the failure of all

rods to insert. Additional actions, such as emergency boration, pose a complication beyond the normal scram response that this metric is attempting the measure. It is allowable to have one control rod not fully inserted since core protection design accounts for one control rod remaining fully withdrawn from the core on a reactor trip. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted. During performance of this step of the EOP the licensee staff would not need to apply the "Response Not Obtained" actions. Other means not specified in the EOPs are not allowed for this metric.

Answer:

NO. All control rods fully inserted as indicated by rod bottom lights.

2. Did the turbine fail to trip?

Did the turbine fail to trip automatically/manually as required on the reactor trip signal? To be a successful trip, steam flow to the main turbine must have been isolated by the turbine trip logic actuated by the reactor trip signal, or by operator action from a single switch or pushbutton. The allowance of operator action to trip the turbine is based on the operation of the turbine trip logic from the operator action if directed by the EOP. Operator action to close valves or secure pumps to trip the turbine beyond use of a single turbine trip switch would count in this indicator as a failure to trip and a complication beyond the normal reactor trip response. Trips that occur prior to the turbine being placed in service or "latched" should have this question answered as "No".

Answer:

NO. The turbine tripped per design.

3. Was power lost to any ESF bus?

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or
- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes.

Answer:

NO. All ESF busses remained energized throughout the trip response.

4. Was a Safety Injection signal received?

Was a Safety Injection signal generated either manually or automatically during the reactor trip response? The questions purpose is to determine if the operator had to respond to an abnormal condition that required a safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged Reactor Coolant System (RCS) inventory, pressure, or temperature severely enough to require a safety injection. A severe steam generator tube leak that would require a manual reactor trip because it was beyond the capacity of the normal at power running charging system should be counted even if a safety injection was not used since additional charging pumps would be required to be started.

Answer:

NO. No SI signal was required or received.

5. Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the steam generators if necessary. The qualifier of “not recoverable using approved plant procedures” will allow a licensee to answer “No” to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures to feed the minimum number of steam generators required by the EOPs to satisfy the heat sink criteria. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-proceduralized operating alignments require an answer of “Yes.” Additionally, the restoration of Feedwater must be capable of feeding the Steam Generators in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding Steam Generators with the Main Feedwater System within 30 minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram this question would not be considered and should be skipped. If design features or procedural prohibitions prevent restarting Main Feedwater this question should be answered as “No”.

Answer:

YES. The loss of power resulted in a complete loss of circulating water and the ability of main feedwater pump turbines to exhaust to the condenser. This question could be answered as "NO" if circulating water, condenser vacuum, and main feedwater could be restored within the 30 minute timeframe, or if an electric driven main feedwater pump was available that did not required condenser vacuum to feed steam generators.

6. Was the scram response procedure unable to be completed without entering another EOP?

The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

Answer:

NO. The reactor trip response procedures were completed without re-entering another EOP.

4.2 BWR FLOWCHART QUESTIONS

4.2.1 BWR Flowchart Basis Discussion

1. **Did an RPS actuation fail to indicate / establish a shutdown rod pattern for a cold clean core?**

   Withdrawn control rods are required to be inserted to ensure the reactor will remain shutdown under all conditions without boron to ensure the reactor will have the required shutdown margin in a cold, xenon-free state.

   Any initial evaluation that calls into question the shutdown condition of the reactor requires this question to be answered "Yes." Required entry into the Anticipated Transient Without Scram (ATWS) leg of the EOP or required use of Alternate Rod Insertion (ARI) call for this question to be answered "Yes." Failure of the rod position indication coupled with the loss of full-in-lights on enough rods to question the cold clean core shutdown status would require this question to be answered "Yes."

   The basis of this step is to determine if additional actions are required by the operators to ensure the plant remains shutdown as a result of the failure of any rods to insert (or indicate inserted). Additional actions, such as boron injection, or other actions to insert control rods to maintain shutdown, pose a complication beyond the normal scram response that this metric is attempting the measure. This question must be evaluated using the criteria contained in the plant EOP used to verify that control rods inserted.

   Basis Discussion

   This question is designed to verify that the Reactor actually tripped and had sufficient indication for operations to verify the trip. As long as a plant uses the EOP questions to verify that the reactor tripped without entering the level/pressure control leg of the EOPs, this question should be answered as "No".

   The generic BWROG EPG/SAG Revision 2 Appendix B statement is offered as an example:

   Any control rod that cannot be determined to be inserted to or beyond position [02 (Maximum Subcritical Banked Withdrawal Position)] and it has not been determined that the reactor will remain shutdown under all conditions without boron, enter Level/Power Control.

   An example from Grand Gulf is as follows.
   Are all control rods inserted to or beyond position 02 (if no then this is a yes for this PI)? Will the reactor remain subcritical under all conditions without boron (if no then this is a yes for this PI)?

   An example from River Bend is as follows.

All rods not fully inserted; and, the reactor will not remain shutdown under all conditions without boron then enter level/pressure control (if yes then this is a yes for this PI).

2. <u>Was pressure control unable to be established following the initial transient?</u>

To be successful, reactor pressure must be controlled following the initial transient without the automatic use of Safety Relief Valves (SRVs) to receive a "No" response. Automatic cycling of the SRV(s) that may have occurred as a result of the initial transient would result in a "No" response, but automatic cycling of the SRV(s) subsequent to the initial transient would result in a "Yes" response. Additionally the SRV(s) cannot fail open. The failure of the pressure control system (i.e. turbine valves / turbine bypass valves / HPCI / RCIC/isolation condenser) to maintain the reactor pressure or a failed open SRV(s) count in this indicator as a complication beyond the normal reactor trip response and would result in a yes answer.

<u>Basis Discussion</u>

This question is designed to verify the ability to transfer reactor energy to the environment using the normal pressure control system. The initial cycling of SRVs is typical for some transients in which there was no failure of the normal pressure control system. Initial operation of the SRVs is not indicative of pressure control problems with the normal pressure control system. Therefore, cycling may occur post-trip until the pressure is controlled. Any subsequent cycling after pressure has been controlled would result in a "YES" answer. Some plant designs also may have a setpoint setdown of SRVs which would open additional SRVs and reduce reactor pressure below the normal SRV closing setpoint. Any additional opening of SRVs to control reactor pressure either automatically or manually indicates the inability of the normal pressure control system to operate properly. Stuck open SRV(s) bypass the normal pressure control system and would result in a "YES" for this PI.

Examples:

A turbine trip occurs and SRVs open to control reactor pressure. The setpoint setdown actuates and reduces reactor pressure from a normal 1025 psig to 930 psig. Following closure of SRVs reactor pressure increases due to decay heat and bypass valves open. This question would be answered "NO".

A pressure controller failure occurs with scram on high reactor pressure. The SRVs open to control reactor pressure. The setpoint setdown actuates and reduces reactor pressure from a normal 1025 psig to 930 psig. Following closure of SRVs reactor pressure increases due to decay heat and SRVs open again to control reactor pressure. The operator takes manual control of bypass valves and opens the bypass valves to maintain reactor pressure. This question would be answered "YES". The yes answer is a result of SRVs opening after pressure control was established from the initial transient.

The pressure controller failure occurs with scram on high reactor pressure. The SRVs open to control reactor pressure. Setpoint setdown actuates and reduces reactor pressure from a normal 1025 psig to 930 psig. Following closure of SRVs

reactor pressure does not increase because the scram occurred with low decay heat load and Main Steam Line drains were open. This question would be answered NO.

3. **Was power lost to any Class 1E Emergency / ESF bus?**

During a reactor trip or during the period operators are responding to a reactor trip using reactor trip response procedures, was power lost to any ESF bus that was not restored automatically by the Emergency Alternating Current (EAC) power system and remained de-energized for greater than 10 minutes? Operator action to re-energize the ESF bus from the main control board is allowed as an acceptable action to satisfy this metric. This question is looking for a loss of power at any time for any duration where the bus was not energized/re-energized within 10 minutes. The bus must have:

- remained energized until the scram response procedure was exited, or
- been re-energized automatically by the plant EAC power system (i.e., EDG), or
- been re-energized from normal or emergency sources by an operator closing a breaker from the main control board.

The question applies to all ESF busses (switchgear, load centers, motor control centers and DC busses). This does NOT apply to 120-volt power panels. It is expected that operator action to re-energize an ESF bus would not take longer than 10 minutes. Plants with a dedicated High Pressure Core Spray (HPCS) bus do not count the HPCS ESF bus in this PI.

Basis Discussion

This question is designed to verify that electric power was available after the reactor trip. Loss of electrical power may result in other criteria being met in this PI. This question is dealing only with electrical power. Should electrical power be maintained or restored within the allowed 10 minutes this question should be answered no. There is an exemption to this step that permits an Operator to manually restore power within 10 minutes as an acceptable alternative. The exception is limited to those actions necessary to close a breaker from the main control board. Actions requiring access to the back of the control boards or any other remote location would require answering this question as “Yes”. It is acceptable to manipulate more than one switch, such as a sync switch, in the process of restoring power to the bus. It is acceptable to close more than one breaker. It is acceptable to restore power from the emergency AC source, such as the diesel generators, or from off-site power. The additional operator action to restore power to additional buses has been discussed and considered acceptable as long as it can be completed within the time limitations of 10 minutes (chosen to limit the complexity) and the constraints of switch operation from the main control board. Any actions beyond these would need to be considered as a complication for this question. Because of the wide variation in power distribution designs, voltage, and nomenclature across the plant designs no specific examples are given here. There is an exception for plant designed with a dedicated High Pressure Core Spray Pump (HPCS) ESF bus. If a plant has a dedicated (only provides power to HPCS equipment) then the HPCS ESF bus does

not have to be considered in this question. This would be similar to a scram with a loss of HPCI which in of itself would not count in this PI.

4. **Was a Level 1 Injection signal received?**

Was a Level 1 Injection signal generated either manually or automatically during the reactor scram response? The consideration here is if the operator had to respond to abnormal conditions that required a low pressure safety injection or respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. This question would include any condition that challenged RCS inventory, or Drywell pressure severely enough to require a safety injection. Plants that do not have a high pressure Emergency Core Cooling System (ECCS) level signal that is different than the low pressure ECCS level signal would ask "was low pressure injection required?"

Basis Discussion

The consideration here is if the operator had to respond to abnormal conditions that required a low pressure safety injection or if they had to respond to the actuation of additional equipment that would not normally actuate on an uncomplicated scram. For some plant designs some events result in a high pressure injection signal on vessel level for a transient. Automatic or manual initiation of low pressure ECCS indicates the inability of high pressure systems to operate properly or that a significant leak has occurred. For plants that do not have a separate high pressure ECCS level signal from their Low level ECCS signal an allowance is made to deviate from this question and answer yes if the system injected.

5. **Was Main Feedwater not available or not recoverable using approved plant procedures?**

If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. The qualifier of "not recoverable using approved plant procedures" will allow a licensee to answer "No" to this question if there is no physical equipment restraint to prevent the operations staff from starting the necessary equipment, aligning the required systems, or satisfying required logic using plant procedures approved for use and in place prior to the reactor scram occurring.

The operations staff must be able to start and operate the required equipment using normal alignments and approved normal and off-normal operating procedures. Manual operation of controllers/equipment, even if normally automatic, is allowed if addressed by procedure. Situations that require maintenance activities or non-proceduralized operating alignments will not satisfy this question. Additionally, the restoration of Feedwater must be capable of feeding the reactor vessel in a reasonable period of time. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within 30

minutes. During startup conditions where Main Feedwater was not placed in service prior to the scram, this question would not be considered, and should be skipped.

Basis Discussion

This section of the indicator is a holdover from the Scrams with Loss of Normal Heat Removal indicator which is being replaced by the USwC indicator. Since BWR designs have an emergency high pressure system that operates automatically between a vessel-high and vessel-low level it is not necessary for the main Feedwater system to continue operating following a reactor trip. However failure of the Main Feedwater System to be available is considered to be risk significant enough to require a yes response for this PI. To be considered available the system must be free from damage or failure that would prohibit restart of the system. Therefore, there is some reliance on the material condition availability of the equipment to reach the decision for this question. Condenser vacuum, cooling water, and steam pressure values should be evaluated based on the requirements to operate the pumps and may be lower than normal if procedures allow pump operation at that lower value.

The 30 minute time frame for restart of main Feedwater was chosen based on restarting from a hot and filled condition. Since this time frame will not be measured directly it should be an estimation developed based on the material condition of the plants systems following the reactor trip. If no abnormal material conditions exist, the 30 minutes should be met. If plant procedures and design would require more than 30 minutes, even if all systems were hot and the material condition of the plants systems following the reactor trip were normal, that routine time should be used in the evaluation of this question. The considered opinion of an on-shift licensed SRO in meeting this timeframe is acceptable.

6. Following initial transient, did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?

This step is used to determine if the scram was uncomplicated and did not require using other procedures beyond the normal scram response. Following the initial transient, maintaining the reactor and drywell pressures below the Emergency Procedure entry values while ensuring reactor level is above the Emergency Procedure entry values allows answering ”No.” The requirement to remain in the EOPs because of reactor pressure/level and drywell pressure following the initial transient indicates complications beyond the typical reactor scram.

The initial Transient is the time from the initiating event until the plant is stable, typically indicated by operations exiting abnormal operating procedures related to the flow chart questions (i.e. BWR EP 2 – RPV CONTROL) and using normal procedures to control the plant. Until the plant is stable the flow chart questions remain applicable. For example in the BWR case study 2 the plant did not lose normal pressure control for several minutes. However once normal pressure control was lost, SRVs had to be manually operated to control reactor pressure. Even if abnormal operating procedures had been exited the plant had not been made stable.

Basis Discussion

When a scram occurs plant operators will enter the EOPs to respond to the condition. In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available, and reactor coolant pressures and temperatures are at expected values and controlled. Once these verifications are done and the plant conditions considered “stable” operators will exit the initial procedure to another procedure that will stabilize and prepare the remainder of the plant for transition for the use of normal operating procedures. The plant would then be ready be maintained in Hot Standby, to perform a controlled normal cool down, or to begin the restart process. The criteria in this question is used to verify that there were no other conditions that developed during the stabilization of the plant in the scram response related vessel parameters that required continued operation in the EOPs or re-entry into the EOPs or transition to a follow-on EOP. Maintaining operation in EOPs that are not related to vessel and drywell parameters do not count in this PI. For example, Suppression Pool level high or low require entry into an EOP on Containment Control. Meeting EOP entry conditions for this EOP do not count in this PI.

4.2.2 BWR Case Study 1

Event Description

A plant experienced an automatic reactor scram as a result of a breaker tripping due to a ground fault on the 34.5kv bus work downstream of the Service Transformer. Loss of service transformer resulted in the loss of power to 2 of 4 balance of plant main busses and one of 3 ESF busses. Emergency Diesel Generator Division 1 started on a loss of power and connected to the ESF bus.

The Main Generator tripped on reverse power and the turbine bypass valves opened to control pressure. No SRVs opened during this event.

Both RPS actuation systems actuated, although for different reasons. The "A" RPS system actuated on loss of power to the Balance of Plant (BOP) (power to RPS "A" MG set) bus since it was powered from a service transformer. With the accompanying loss of power to the condensate/feed water system components, the "B" RPS system actuated on low reactor water level of 11.4 inches. All control rods inserted to 00 position.

Reactor water level dropped to approximately -75 inches on wide range level instrumentation before the High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) systems initiated at -41.6 and restored level to the EOP specified band. Level control was transferred to the startup level controller and both HPCS and RCIC were secured.

Primary, secondary, and drywell isolations occurred as designed at -41.6 inches along with the start of the Division III (HPCS) diesel.

A walk down of the switchyard following the reactor scram discovered that a raccoon had entered the service transformer area and caused the ground fault.

Prior to the scram power was 100% with both main feedwater pumps in service.

Feedwater was unavailable to control level.

Vessel level was restored to the EOP level band (+11.4 inches [low level scram setpoint] to + 53.5 inches [high level feedpump trip setpoint]) without any additional scram signals. Drywell pressure was not affected noticeably by this event.

1. **Did RPS actuation fail to indicate/establish a shutdown rod pattern for a cold clean core.**

   Answer: No. As indicated Alternate Rod Insertion.

   Alternate yes / no answers as examples:

   Answer: No. While all rods did not insert, reactor engineering, using an approved procedure, ran a computer calculation that determined the reactor would remain shutdown under cold clean conditions.

Answer: Yes. All rods did not insert, reactor engineering could not be contacted so operations entered the ATWAS leg of EOPs. Subsequent calculation by reactor engineering determined the reactor would remain shutdown under cold clean conditions.

Answer: Yes. All rods failed to insert and the reactor power was in excess of 4%.

2. **Was pressure control unable to be established following initial transient?**

   Answer: No. The Main Turbine did not trip as a result of the switchyard transient. The turbine did eventually trip on reverse power at which time the turbine bypass valves operated to control reactor pressure.

   Alternate yes / no answers as examples.

   Answer: No. The main turbine tripped resulting in opening of all 20 SRVs. Following the initial opening main turbine bypass valves opened to control pressure.

   Answer: Yes. The main turbine tripped resulting in opening of all 20 SRVs. As a result of pressure controller problems operations manually opened an SRV to control reactor pressure

   Answer: Yes. The main turbine tripped and as a result of loss of condenser vacuum SRVs were used to control reactor pressure.

3. **Was power lost to any class 1E Emergency/ESF bus?**

   Answer: No. While an ESF bus (Division I) did lose power, the EDG started and restored power.

   Alternate yes / no answers as examples.

   Answer: No. Power was lost to an ESF bus. The EGD was out of service and power was restored by closing an alternate feed breaker from the control room.

   Answer: Yes. Power was lost to an ESF bus. The EDG was out of service. Power was restored to the ESF bus by resetting a lockout in the back panels and closing the breaker from the control room.

4. **Was a level 1 Injection signal received?**

   Answer: No. Vessel level did drop to approximately -75 inches resulting in the automatic start of RCIC and HPCS. However, for this plant level 1 is -150.3 inches.

   Alternate yes / no answers as examples,

   Answer: No. HPCS and RCIC failed to start/run. Level dropped to -110 inches but was stabilized by use of Control Rod Drive (CRD) pumps.

Answer: Yes. HPCS and RCIC failed to start/run. Vessel level dropped to near -150.3 inches and operators manually initiated low pressure ECCS however level was restored by CRD flow.

5. **Was main feedwater unavailable or not recoverable using approved plant procedures following the scram?**

   Answer: No. While some of the condensate system pumps lost power resulting in both feedwater pumps tripping, the feedwater system was restored by use of normal procedures. Feedwater was restored and RCIC/HPCS and secured.

   Alternate yes / no answers as examples

   Answer: No. Level was restored by RCIC. A condensate and condensate booster pump remained operating. While both feed water pumps tripped there was no known issues with either pump that would prevent restarting if needed.

   Answer: Yes. Level was restored by RCIC. A condensate and condensate booster pump remained operating. Both feedwater pumps tripped and problems with condenser vacuum prevented restart of the feed pumps if they had been needed.

6. **Following initial transient did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOPs?**

   Answer: No. Following the initial event reactor pressure was controlled by the turbine pressure control system below the high reactor pressure entry condition of 1064.7 psig [reactor high pressure scram setpoint]. Vessel level was restored to the EOP level band (+11.4 inches[low level scram setpoint] to + 53.5 inches [high level feedpump trip setpoint]) without any additional scram signals. Drywell pressure was not affected noticeably by this event. The reactor scram signal on Division II side was reset at 8:21.

   Alternate yes / no answers as examples.

   Answer: No. Following the initial event reactor pressure was controlled by the turbine pressure control system below the high reactor pressure entry condition of 1064.7 psig [reactor high pressure scram setpoint]. Vessel level was restored to the EOP level band (+11.4 inches[low level scram setpoint] to + 53.5 inches [high level feedpump trip setpoint]) without any additional scram signals. The vessel was overfeed twice, resulting in a high level trip of the feedpump. However, when level cleared the high level trip setpoint the feed pump was restored to operation by procedure. Drywell pressure was not effected noticeably by this event.

   Answer: Yes. Following the initial event reactor pressure was controlled by the turbine pressure control system below the high reactor pressure entry condition of 1064.7 psig [reactor high pressure scram setpoint]. Vessel level was restored to the EOP level band (+11.4 inches[low level scram setpoint] to + 53.5 inches [high level feedpump trip setpoint]) however startup level control valve problems resulted in an additional low level scram signal.

4.2.3 BWR Case Study 2

Event Description:

A plant received an automatic scram on a Turbine Control Valve Fast Closure as a result of a load reject. The initiating event for the automatic scram was closure of a 500 kV disconnect which was open for maintenance. High winds contributed to the disconnect closing and contacting the energized bus. The pressure exerted by the wind on the disconnect blades overcame the spring counterbalance of the disconnect switch. Additionally, the "Open" position lock bracket on the motor operator was broken. A low impedance ground fault was created through the installed maintenance grounds.

The fault resulted in actuation of the Service Transformer differential lockout and the West 500 kV buss differential lockout. Breakers opened as designed due to the Service transformer lockouts and the West Bus lockouts. This resulted in the loss of one of the 2 service transformers and all plant busses normally powered from this transformer, including safety related busses Division 2 and 3 which were lined up through the service transformer. The Division 2 & 3 EDGs subsequently started and appropriately re-energized the ESF busses.

Within 3-5 cycles of the ground fault, breakers opened at a near by substation de-energizing the remaining 500 kV incoming power to the switchyard. This left the main generator supplying power to some of the in-house loads including Balance of Plant and Division I Safety Related Bus (ESF Division I)

At this time, the load reject relays actuated producing a Turbine Control Valve Fast Closure (TCV/FC) signal and a subsequent reactor scram. Approximately 4 seconds later the turbine speed increased to 1900 rpm and generator output frequency increased to 63.5 Hz. Subsequently, the turbine tripped as the generator remained excited and the turbine-generator began coasting down into an under-frequency condition. Generator output voltage remained constant.

As the turbine coasted down an under frequency condition occurred resulting in the turbine output breaker opening. This resulted in loss of the Division 1 ESF bus as well as loss of the 2nd service transformer and all remaining balance of plant loads about 2-3 minutes following the initial scram.

In summary the loss of power to the plant BOP, which resulted in loss of Feedwater and normal pressure control occurred in stages over several minutes, but still with in the initial transient. The ESF buses also lost power but were restored automatically by the D/Gs.

1. **Did RPS actuation fail to indicate/establish a shutdown rod pattern for a cold clean core?**

   Answer: No. Alternate Rod Insertion.

2. **Was pressure control unable to be established following initial transient?**

   Answer: Yes. While SRVs open once on the load reject and steam pressure was reduce as the turbine coasted down the loss of all balance of plant power several minutes later when the main generator tripped resulted in loss of pressurized fluid for the bypass valves.

Additionally, the loss of the balance of plant power resulted in loss of main condenser cooling which prevented use of the main condenser as a heat sink. This resulted in the use of the SRVs to control reactor pressure following the initial scram.

3. **Was power lost to any class 1E Emergency/ESF bus?**

   Answer: No. While all ESF busses lost power the EDG started and restored power automatically.

4. **Was a level 1 Injection signal received?**

   Answer: No. Vessel level did drop to about -42 inches resulting in auto start of RCIC. The level 1setpoint is -150.3 inches.

5. **Was main feedwater unavailable or not recoverable using approved plant procedures following the scram?**

   Answer: Yes. The loss of balance of plant power after several minutes resulted in loss of all condensate and condensate booster pumps as well as loss of power to condensate and feedwater valves, preventing the use of feedwater to control level. Level was controlled by RCIC.

6. **Following initial transient did stabilization of reactor pressure/level and drywell pressure meet the entry conditions for EOP's?**

   Answer: No. Following the initial event reactor pressure was controlled by the SRVs to maintain the reactor pressure below the EOP entry setpoint of 1067.5 psig [reactor high pressure scram setpoint]. The vessel level was restored to the EOP level band (+11.4 inches[low level scram setpoint] to + 53.5 inches [high level feedpump trip setpoint]) by use of RCIC with one additional scram signal on high level Drywell pressure did increase slightly as a result of loss of cooling but never exceeded the EOP setpoint of 1.23 psig. The EOP for containment control was entered as a result of high suppression pool level due to swell from the heat/mass addition from the operation of RCIC.