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PRA Applications at an Operating Nuclear Utility

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ABSTRACT

Since 1987, the Gulf States Utilities (GSU) Engineering Analysis staff at River Bend Station (RBS) has been using Probabilistic Risk Assessment (PRA) methods to provide upper management, nuclear licensing and the nuclear plant staff an indication of the safety significance for daily plant situations.

The first segment of the PRA (i.e., Level 1 PRA) is usually referred to as the Probabilistic Safety Analysis (PSA). The PSA's performed at RBS consist of addressing the safety significance for several Nuclear Regulatory Commission (NRC) issues, major modifications to the nuclear plant, nuclear licensing concerns and plant operation and Technical Specification concerns.

Although some safety analysis evaluations may cause the utility to lose revenue, the long term effects of PSA integration into day to day decisions made at the plant will save the utility significant resources during the life of the plant and provide assurances that the plant remains safe and reliable.

INTRODUCTION

Since the Three Mile Island-2 (TMI-2) accident in 1979, severe accident issues have permeated Nuclear Regulatory Commission (NRC) thinking in regulating nuclear power station construction, design, operation, and maintenance activities. Subsequent to the TMI-2 accident, the NRC formulated a Severe Accident Policy.

The Severe Accident Policy is a guide to regulatory decision-making. The policy provides general procedures for staff approval of items related to severe accidents. Even though the NRC has stated that it believes existing nuclear power plants pose no undue risk to the health and safety of the public, the Severe Accident Policy statement indicates that all plants will be required to perform a probabilistic safety analysis (PSA) to verify that this conclusion is true and to identify any potential outliers or plant vulnerabilities that might be plant specific. The NRC had recognized the value of PSA in assuring the safety of plant design and operation. Plant specific safety evaluations can be accomplished through the use of Probabilistic Risk Assessment (PRA) methods.

A full scope PRA is composed of three segments. The first segment is the Level I PRA and is considered a PSA leading to the determination of core damage frequency (CDF). The CDF provides a number which represents how often the reactor core can be damaged per reactor year of operation. For example, a CDF equal to 10^{-6} means that the reactor core could be damaged once in every million years. The CDF provides analytical evidence based on important initiating events (e.g., loss of coolant accidents (LOCAs) and potential transients) and the availability of equipment important to mitigating core damage. The second segment of the PRA is the Level II PRA which provides analytical evidence to the containment failure probability, which may or may not require reactor vessel melt through. The third segment of the PRA is the offsite consequences to the general public subsequent to the failure of the containment. The PRA method of analysis is the most practical way of quantifying nuclear reactor safety with respect to the use and operation of procedures and equipment to mitigate the consequences of a severe accident.

In 1987 Gulf States Utilities (GSU), in anticipation of Generic Letter (GL) 88-20, began work on a focused-PRA[1] of River Bend Station (RBS), a 2894-MW (thermal) General Electric boiling water reactor product line 6 (BWR/6) operated by GSU. The BWR/6 reactor vessel is housed in a GE MARK-III containment. RBS is located approximately 25 miles north of Baton Rouge, Louisiana.

Since the PSA is the first segment of the PRA, GSU began using PSA type evaluations in 1987 to support plant operation, maintenance activities, nuclear licensing regulatory issues, and engineering decision-making. The RBS plant specific PSA was developed using methods provided by NRC contractors[2].

DESCRIPTION OF PRA METHODS

GSU believes emphasis should be placed on mitigating core damage, therefore the figure of merit used in assessing safety significance is CDF. This can be determined by using the results of the PSA (i.e., Level I PRA). The PSA is comprised of an extremely detailed model of 23 major systems that are important to plant safety with a large number of these systems modeled to

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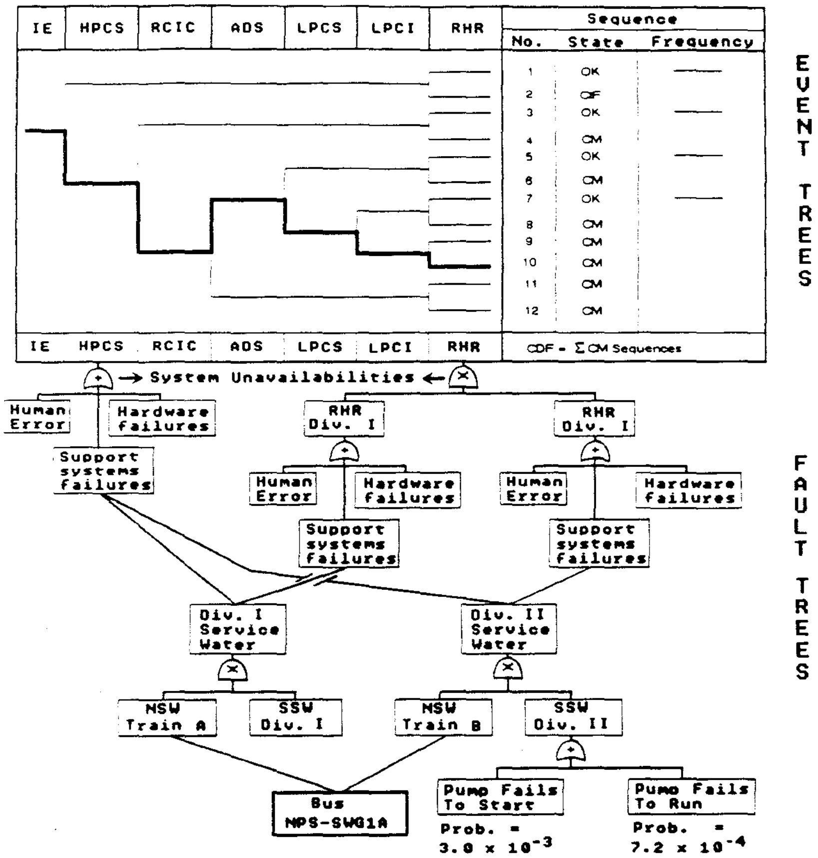
the component level. The modeling methodology employed by GSU is documented in Reference 2. And example of typical sequence model is shown in Figure 1. The sequence model is composed of event trees which identify the initiating events and systems called upon to mitigate the consequences of the event. As seen in Figure 1, the event can progress depending on the availability of mitigating systems to an "OK" status (i.e., no core damage) or to a "CM" status (i.e., core melt or core damage). The fault trees provide system unavailability information to the event tree models as shown in Figure 1. The fault trees consist of components and other contributing factors that model the system functionability. Also included are factors that integrate human error and various types of equipment failure probability. As one can see in Figure 1, interactions with other support systems are also modeled. With this detailed model one can see how various parameters can be changed in the model to determine safety significance.

For example, instead of the normal service water pump being unavailable based on normal availability of the pump, the pump may be out of service based on maintenance activities. This would change the unavailability of the service water pump from .005 to 1.0 and therefore propagate through the analytical model calculation to ultimately impact the CDF. This same technique can be used to assess human reliability assumptions, changes to maintenance practices, operational changes, and design changes. GSU has used this concept to assess the safety impact on many decisions made at RBS.

As the PSA method of assessing plant safety became known to RBS plant staff, more requests to evaluate changes to the plant and to resolve regulatory questions were received. These types of assessments provided valuable insights to plant management in addition to beneficial cost reduction by eliminating or reducing work activities on equipment that had little impact on plant safety. Also these insights were used to convince regulatory agencies that some required activities could be delayed without impacting plant safety.

PROBABILITY RISK ASSESSMENT METHODS AND APPLICATIONS



EVENT TREES - "Map" System Responses Leading To Core Damage

FAULT TREES - Models the Ways a System can Fail

FAILURE DATA - Plant Specific and Industry Failure Information Utilized to Determine Component Unavailabilities

EVENT TREES AND FAULT TREES

FIGURE 1

USES OF PRA

Table 1 provides a summary of uses for the PRA at RBS. The first column in Table 1 provides a summary description of the task, the second column identifies the customer (i.e., major groups that are supported at RBS), the third column identifies the document or source that requested the work to be performed and the fourth column identifies outage related work. The customer can be divided into three major support areas (i.e., regulatory (7 items), plant staff (12 items) and engineering (10 items)). As the RBS PRA becomes more mature, more integration into maintenance and technical specification support will take place.

The regulatory evaluations are typically performed to satisfy NRC questions and to support the Technical Specification questions.

USING PRA FOR COMPLIANCE ISSUES

During a recent plant startup, it was determined that the reactor core isolation cooling (RCIC) system was inoperable. One of the reasons for RCIC during start-up is to mitigate the consequences of a control rod drop ensuring that a redundant safety related high pressure water source is available (i.e., in addition to high pressure core spray (HPCS)). Without RCIC operable, the plant was prohibited by Technical Specifications from entering the RUN mode. Therefore, the plant startup was placed on hold until the compliance issue could be resolved with the NRC to allow entrance to RUN mode without RCIC operable. Technical Specifications provide specific direction to the operators so compliance to regulatory mandates can be maintained. As part of the technical justification for this authorization of compliance, a PSA was performed assuming RCIC inoperable. With RCIC operable, total CDF was 2.07×10^{-6}. With RCIC inoperable, total CDF was increased to 9.6×10^{-6}, or by a factor of 4.6. However, this was still an order of magnitude below the NRC safety goal of 1.0×10^{-4} for core damage events. Also, this change is within the uncertainty of PRA techniques. This PSA evaluation helped convince the NRC to grant the requested waiver of compliance, which allowed plant startup to continue. Without this authorization, the plant could not start-up until the RCIC system became operable. Although the cost benefit would depend on the length of time required to have an operable RCIC system, based on a $180,000 per day replacement power cost the savings are considered significant.

TABLE 1
PRA PLANT SUPPORT 1987 TO PRESENT

		CUSTOMER *	DOCUMENT	OUTAGE
1)	Operations with ADS inoperable due to SVV compressors	Licensing/Plant Staff - R	Direct Request	
2)	Drywell hydrogen igniter safety assessment	Licensing/EQ - R	LER 90-048	
3)	Waiver of compliance on drywell airlock doors	Licensing/Plant Staff - P	T/S 3.6.2.3	RF3
4)	Waiver of compliance on Mode change with RCIC inoperable	Licensing/Plant Staff - P	T/S 3.04 & 4.7.3b	RF3
5)	Evaluation of HPCS Rosemount transmitters	Licensing/Plant Staff - P	CR 90-1103	RF3
6)	Ranking of MOV's by risk	Design Engineering - E	NRC GL 89-10	RF3
7)	Estimate of the probability of SSE occurring in a 30 day period in support of RF3 control rod storage plans	Plant Staff - P	Direct Request	RF3
8)	Probability of SSE or OBE	Licensing - R	TSI (OPDRV)	RF3
9)	Review of BWROG safety assessment on MOV isolation	Design Engineering - E	NRC GL 89-10	RF3
10)	Standby service water system single active failure analysis	Licensing - R	NRC GL 89-13	RF3
11)	Reliability study for Olin 450 psig	GSU Industrial Marketing - R	Direct Request	
12)	Asea Brown Boveri circuit breaker failures	Operations - P	EEAR 89-R0161	
13)	Impact of a short on DIV III bus while testing DIV III diesel generator	Design Engineering - E	Direct Request	
14)	Feedwater control - high level trip power supply	Design Engineering - E	Direct Request	
15)	24 hour extension of LCO due to 1HVC*AHU2A	Licensing - R	LCO	
16)	Review of Scram 90-02	Operations - P	Direct Request	
17)	Plant operations without auxiliary boiler	Design Engineering - E	Direct Request	
18)	Evaluation of 54 month instrument calibration interval	Maintenance - P	CR 89-1265	
19)	Safety evaluation of proposed alternate electrical distribution alignment	Design Engineering - E	Direct Request	
20)	Analysis of the safety impact of having valves listed in the FHA as de-energized, energized	Design Engineering - E	Direct Request	
21)	Topaz inverter analysis	Plant Staff - P	Direct Request	
22)	Temperature of a conduit near 1G33*MOVF040	Design Engineering - E	Direct Request	
23)	NRC Augmented Inspection Team on interfacing system LOCA	Senior Management - P	CR 90-0116	
24)	Comparison of RETRAN model vs. simulator model for ADS actuation at 100% power	Operations/Training - P	CR 90-0116	
25)	PSA of alternate shutdown cooling during mid-cycle 3 outage	Outage Management - P	EEAR 89-E0218	
26)	Effect of having a preferred station transformer out of service on core damage frequency	Senior Management - P	Direct Request	RF2
27)	Probability of Anticipated Transient without Scram (ATWS) Events leading to Core Damage	Design Engineering - E	Direct Request	
28)	Risk/Benefit analysis on turbine stop/control valve testing with bypass	Design Engineering - E	MR 89-0046	
29)	Single failure scram analysis	ISEG	Direct Request	

* R denotes regulatory, P denotes plant support and R and E denotes engineering

USING PRA TO PRIORITIZE

As part of River Bend Station's response to NRC Generic Letter (GL) 89-10, the PRA group was asked to evaluate priority of motor-operated valves (MOVs) for inclusion in the MOV testing program. GL 89-10 stipulates that a large number of safety related MOVs required testing to ensure operability and conform to the original design basis. Approximately 200 safety related valves were identified to be tested. If the work was performed in a short time period, resources of maintenance and engineering would be overextended. Therefore, some way was necessary to identify the most important valves with respect to safety and inspect them first. As a result, sixty (60) MOVs were determined to be most important relative to plant safety. A list of these valves was developed and provided to Design Engineering for their use in preparing the MOV testing schedule. The benefit in this evaluation allowed resources to be allocated only to the most important activities with respect to safety and allowed the deferment of activities that had a minimal impact on plant safety thereby optimizing allocation of scarce resources.

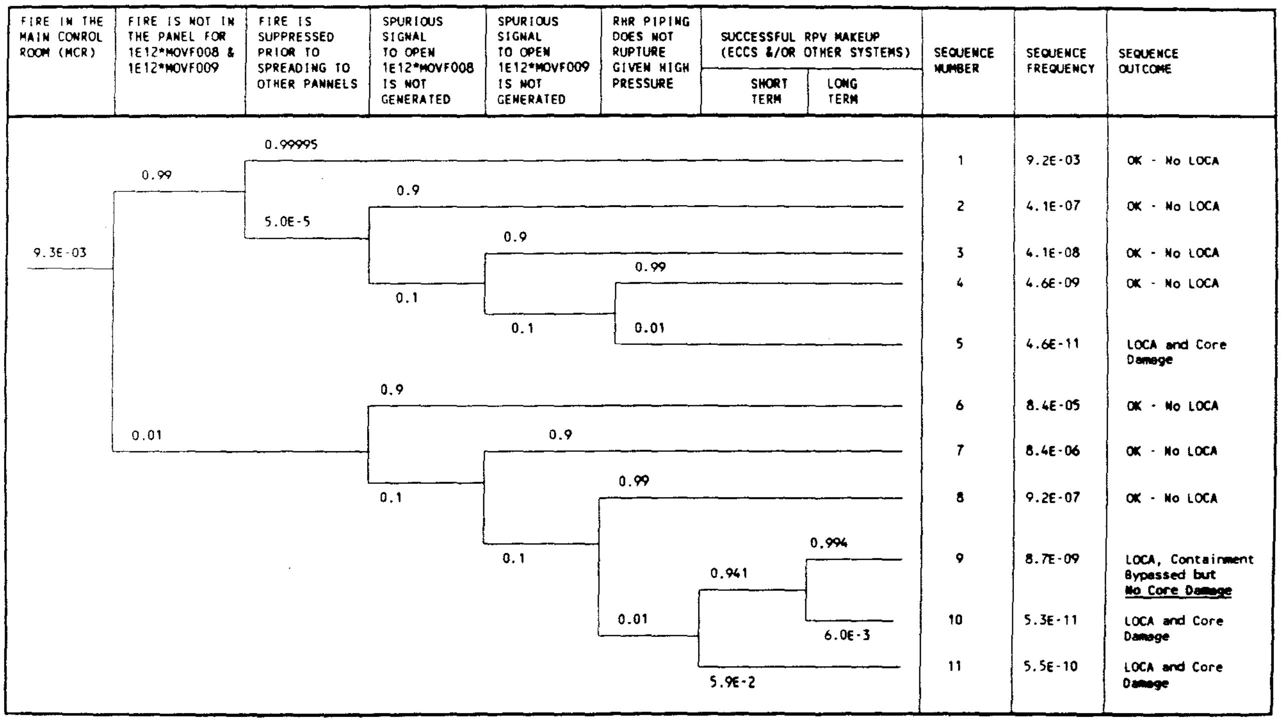
EXTENSION OF TECHNICAL SPECIFICATION LCO

During normal operations, one train of the heating, ventilation, and air-conditioning (HVAC) serving safety-related switchgear and battery rooms was declared inoperable. Plant Staff anticipated the need for a 24 hour extension to the 7-day Technical Specification Limiting Condition for Operations (LCO) governing this situation. A PSA was performed to support the LCO extension request. This analysis demonstrated that the 24-hour extension increased CDF from 3.61×10^{-6} to 3.65×10^{-6}, or an increase of only 4×10^{-8} per year. Therefore, the LCO extension had no significant impact on plant safety. This LCO extension allowed the plant to continue to operate without a costly shutdown thereby saving significant resources for GSU while keeping the plant safe and reliable.

USING PRA TO SAVE ON MAINTENANCE

Plant Engineering requested an evaluation of the potential plant maintenance impact of extending the calibration intervals to 54 months for a number of safety-related instruments. These instruments were divided into two groups; those that provide information or alarm functions only and those that provide signals for automatic action. PSAs were performed on the instruments controlling automatic actions to demonstrate that this extension would have no significant impact on the core damage frequency at River Bend Station. For the instruments providing information or alarms, operating procedures were reviewed to determine their impact, if any, on the core damage frequency. Based on this evaluation, plant maintenance requirements were reduced for 28 instruments without impacting plant safety. This provides a reduction in maintenance cost for the life of the plant and a significant cost savings for GSU in reduced maintenance manpower requirements.

EVENT TREE FOR A INTERFACING SYSTEM LOCA DUE TO A FIRE IN THE MAIN CONTROL ROOM



PROBABILITY OF PIPE RUPTURE = 1.0×10^{-2}

FOR ECCS - SHORT TERM ASSUMED THAT LPCS IS FAILED, ONLY HPCS CAN RESPOND TO BREAK

TOTAL CORE DAMAGE FREQUENCY DUE TO FIRES IN MCR = 6.5×10^{-10} Per Reactor-Year

FIGURE 2

PRA EVALUATION OF TRANSFORMER OUT OF SERVICE

At the end of RBS Refueling Outage-2 (RF2), Engineering Analysis was requested to determine the impact on safety due to operating with one non-safety-related transformer out of service. The transformer in question is referred to as a preferred transformer 1RTX-XSR1A. A schematic of RBS electrical distribution is shown in Figure 3. During plant start-up, power to drive auxiliary equipment (i.e., service pump, feedwater pumps, condensate pumps, etc.) is taken from offsite (preferred power) through transformers 1RTX-XSR1A and 1RTX-XSR1B. When plant power generation is sufficient, the power to the auxiliaries is taken from normal station power through transformers 1STX-XNS1A and 1STX-XNS1B. During a loss of generator transient, the loads are shifted from normal station power to preferred power. If one of the preferred transformers is not available, the auxiliaries such as feedwater and service water would not have power, thereby not available for restoration of plant conditions to normal. Based on GSU's plant specific evaluation, this condition (i.e., start-up without preferred transformer) was determined to have a significant the impact on safety. Although this transformer was not required to be in compliance with Technical Specifications, a PSA indicated plant operation without this transformer could increase the core damage frequency significantly. During this analysis, a comparison between the progression of the accident, under both the normal and current transformer configurations, to the required operator response was developed. This comparison is shown in Figure 4. This method of presentation allowed the differences to be easily noted. Figure 4 provided practical evidence to Operations that starting up without a preferred transformer is not a wise thing to do. The top part of Figure 4 shows the possible situations with both preferred transformers available that could develop and the calculated frequency. The bottom part of Figure 4 shows the possible situations that could develop and the calculated frequency with only one preferred transformer available. As one can see, a normal scram which can occur, based on the first four years of operation at RBS with a frequency of 6 per year, will be much more difficult for the operators to control with only one transformer in place. Based on these comparisons, it was relatively easy to convince Plant Staff that we should not start up with only one preferred transformer. Based on this PSA, plant start-up was delayed approximately two weeks while a replacement transformer was installed. Although plant start-up was allowed by Technical Specifications, GSU felt the prudent action was to delay start-up to minimize the chances for adverse operation of the plant. In this case, revenue losses were incurred by GSU, but GSU avoided a high risk situation with a qualified analysis.

LOADS OF INTEREST

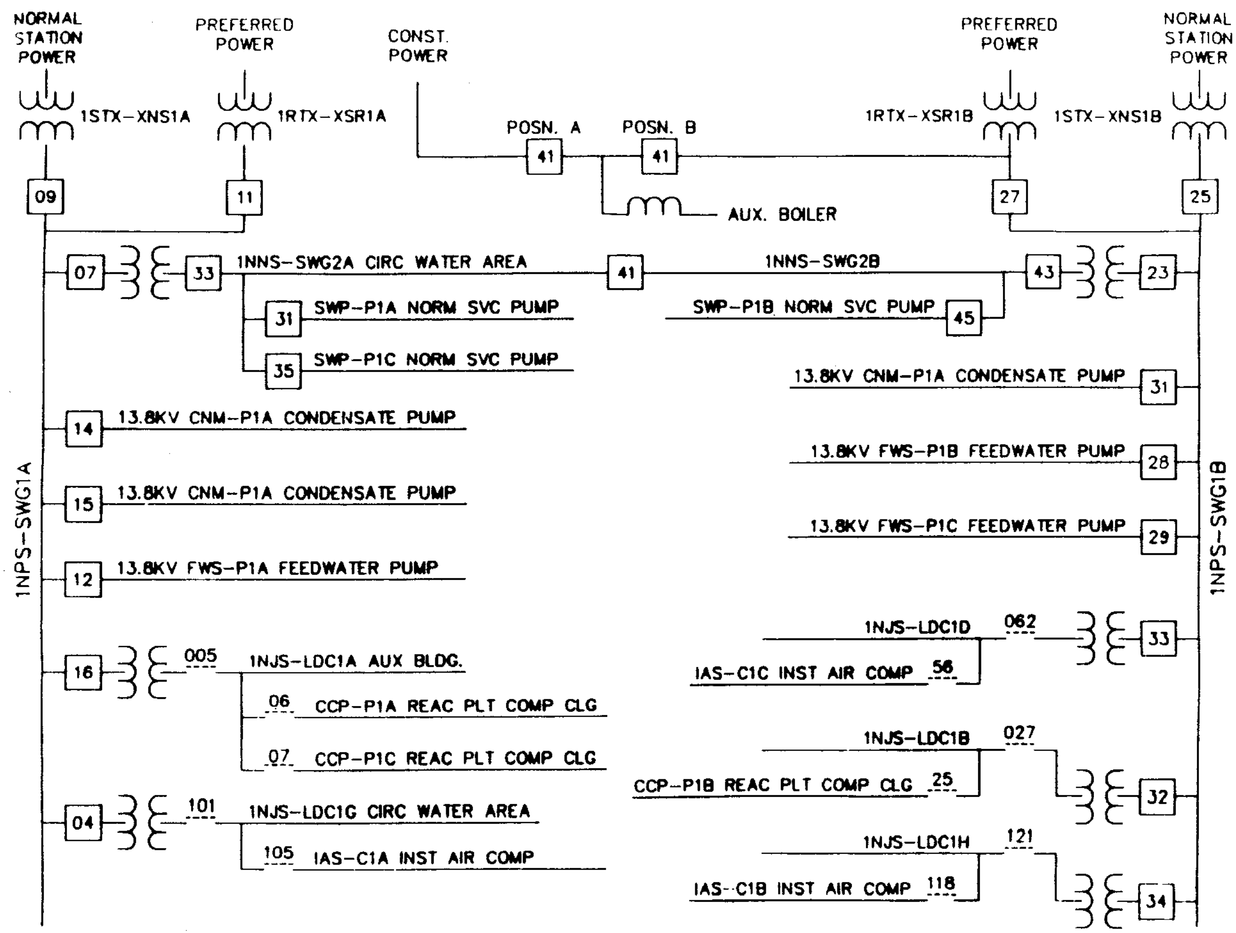


FIGURE 3

COMPARISON OF RIVER BEND TRANSIENT SEQUENCES

NORMAL CONFIGURATION W/ PREFERRED E & B AVAILABLE

100% POWER	SCRAM OCCURS FREQUENCY=6/YR RESPONSE: LOSS OF NORMAL XFORMERS OPERATOR ACTIONS: AOP-1 REACTOR SCRAM AOP-2 MAIN TURB TRIP MUST ADDRESS CAUSE OF SCRAM STATUS: NORMAL SCRAM	LOSS OF PREFERRED-E AND FEEDWATER PROB=1.0 X E-04 RESPONSE: LOSS OF NPS-A LOSS OF FEEDWATER DEGRADED NSW DEGRADED CONDENSATE DEGRADED INSTR AIR DEGRADED RECIRC AUTO START SSW OPERATOR ACTIONS: AOP-3 AUTO ISOLATIONS AOP-6 COND/FW FAILURES AOP-10 LOSS OF ONE RPS AOP-11 LOSS OF RPCCW AOP-24 DECREASE IN RECIRC STATUS: N.O.U.E.	LOSS OF SSW PROB=3.2 X E-03 RESPONSE: LOSS OF ECCS (4-16 HOURS) OPERATOR ACTIONS: AOP-16 LOSS OF SSW STATUS: ALERT POTENTIAL UPGRADE TO S.A.E. HPCS AND RCIC FOR MAKEUP	OPERATOR RECOVERY ACTIONS FAIL PROB=1 X E-02 POTENTIAL RECOVERY ACTIONS: RESTORATION OF ROOM COOLING REALIGNMENT OF SSW CROSS TIE NPS A&B BUSES RECOVERY OF HEAT SINK STATUS: HPCS AND RCIC FAIL ON ROOM COOLING SITE AREA EMERGENCY	

CONFIGURATION W/O NORMAL-B TRANSFORMER

100% POWER	SCRAM OCCURS FREQUENCY=6/YR RESPONSE: LOSS OF NPS-B DEGRADED FEEDWATER DEGRADED CONDENSATE DEGRADED INSTR AIR RECIRC PUMP TRIP DEGRADED NSW OPERATOR ACTIONS: AOP-1 REACTOR SCRAM AOP-2 MAIN TURB TRIP AOP-3 AUTO ISOLATIONS AOP-6 COND/FW FAILURES AOP-10 LOSS OF ONE RPS AOP-24 DECREASE IN RECIRC STATUS: MORE SEVERE THAN NORMAL SCRAM MORE SEVERE THAN IAS SCRAM	LOSS OF PREFERRED-E PROB=3.5 X E-03 RESPONSE: LOSS OF NPS-A LOSS OF FEEDWATER LOSS OF CONDENSATE LOSS OF INSTR AIR LOSS OF RECIRC LOSS OF NSW LOSS OF CB CHILL WATER OPERATOR ACTIONS: AOP-5 LOSS OF COND VAC AOP-9 LOSS OF NSW AOP-11 LOSS OF RPCCW STATUS: N.O.U.E. POTENTIAL UPGRADE TO ALERT MORE SEVERE THAN IAS SCRAM	LOSS OF SSW PROB=3.2 X E-03 RESPONSE: LOSS OF ECCS (4-16 HOURS) OPERATOR ACTIONS: AOP-16 LOSS OF SSW STATUS: ALERT POTENTIAL UPGRADE TO S.A.E. HPCS AND RCIC FOR MAKEUP CORE DAMAGE W/O RECOVERY	OPERATOR RECOVERY ACTIONS FAIL PROB=1 X E-02 POTENTIAL RECOVERY ACTIONS: RESTORATION OF ROOM COOLING REALIGNMENT OF SSW STATUS: HPCS AND RCIC FAIL ON LOSS OF RM COOLING CORE DAMAGE W/ RECOVERY SITE AREA EMERGENCY	SPECIAL RECOVERY ACTIONS FAIL PROB=0.1 RECOVERY OF NSW VIA GRANT SUB TIE-IN RECOVERY THROUGH FANCY POINT (LOW IMPACT)

FIGURE 4

CONCLUSION

The PRA at River Bend Station was initially developed to address the requirements of NRC Generic Letter 88-20. However, in addition to fulfilling this regulatory role, the River Bend PRA has been utilized to support plant evolutions. At River Bend, the PRA represents an analytical tool capable of evaluating changes to plant design, operations and maintenance. Supporting requests for compliance issues and LCO extensions, quantifying the safety extensions of calibration intervals are a few examples of the changes which PSAs can evaluate. Such changes can have either positive or negative impacts on plant safety and reliability. Integration of PRA techniques into day to day decision-making at the plant can lead to significant resource savings while ensuring that margins of safety are preserved.

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