NUCLEAR POWER PLANT RISK-INFORMED SURVEILLANCE FREQUENCY CONTROL PROGRAM IMPLEMENTATION AT THE DUKE CATAWBA NUCLEAR PLANT WITH A FOCUS ON INSTRUMENTATION AND CONTROL SYSTEMS

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ABSTRACT

This paper summarizes an updated process for risk-informed surveillance frequency control program (SFCP) implementation at the Catawba Nuclear Power Plant in the past year. This program includes selection and prioritization of specific target surveillance test interval extensions; and development, review, and implementation of surveillance test risk informed documented evaluation (STRIDE) packages designed to support extension of conventional surveillance requirement test intervals, in accordance with "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies, Industry Guideline," NEI 04-10, Revision 1 [1]. The scope of work associated with STRIDE development includes probabilistic risk assessment (PRA) case studies, deterministic assessment (DA) evaluations, and, where required, instrument drift evaluation (IDE). The STRIDE implementation efforts have also included support of independent decision-making panel (IDP) meetings at the implementing power stations and IDP member training. The purpose of this paper is to provide a presentation of a refined process for STRIDE development with a focus on instrumentation and control systems based on author experience, which includes support for the development of multiple STRIDE packages for the Catawba Nuclear Plant. This paper outlines a framework for practical implementation of an SFCP within the context of an integrated risk-informed performance-based regulation application program with emphasis on instrumentation and control systems.

Key Words: Risk-Informed Performance-Based Regulation, Risk-Informed Applications, Surveillance Frequency Control Program (SFCP), Instrumentation and Control System Drift Evaluation

1 INTRODUCTION

On September 19, 2007, the U.S. Nuclear Regulatory Commission (NRC) issued its “Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 04-10, Revision 1, “Risk-Informed Technical Specification Initiative 5B, “Risk-Informed Method for Control of Surveillance Frequencies” (TAC NO. MD6111)” (Reference 2) authorizing the application of Reference 1 in implementing and maintaining nuclear power plant component surveillance test intervals (STIs) within approved SFCPs. Since early 2008, ABSG Consulting Inc. (ABS Consulting) has supported STRIDE development for the STP Nuclear Operating Company (STPNOC) SFCP applying Reference 1. In March 2011, the Strategic Teaming and Resource Sharing (STARS) alliance authorized a major project to implement SFCPs during the 2011-2016 time period at the following seven nuclear power plants: Callaway (CNPP), Comanche Peak (CPNPP), Diablo Canyon (DCPP), Palo Verde (PVNGS), San Onofre (SONGS), now closed, South Texas (STPEGS), and Wolf Creek (WCNPP). In 2015 and 2016, the authors of this paper supported the Duke Catawba Station for the STRIDE development for the 7300 instrumentation extension of their Channel Operational Test from monthly or semi-annual to 18 months, which is the subject of this paper. The general scope of work associated with STRIDE development includes three major task areas: probabilistic risk assessment (PRA), deterministic assessment (DA), and instrument drift evaluation (IDE). This paper provides a discussion of the methods applied for these scopes of work, with an emphasis on IDE.

2 METHODOLOGY AND DISCUSSION

In 2015 and 2016, the authors of this paper supported the Duke Catawba Station for the STRIDE development for the 7300 instrumentation extension of their Channel Operational Test from monthly or semi-annual to 18 months. This included the Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS) functions including:

- Boron Dilution Mitigation System (BDMS)
- Containment Purge Control System (CPCS)
- Nuclear Instrumentation System (NIS)
- Non-Overpower Delta Temperature Parameters(Non-OPDT)
- Overpower Delta Temperature functions (OPDT)
- Overtemperature Delta Temperature functions (OTDT)

In their support of TSTF-425 (aka Industry Initiative 5b) SFCP implementation at Catawba and several other commercial nuclear power plants, the authors of this paper have performed and reviewed three primary scopes of work, including PRA, DA, and IDE. A general overview of the PRA and DA processes will be summarized in this section, the IDE process will be presented in greater detail, and a summary of the results from Catawba will be included.

2.1 PRA Process Overview

Reference 1 provides the NRC-endorsed industry guidance for performing PRA risk assessments of proposed STI changes. This procedure provides clarifications and refinements to this guidance, where applicable. However, since PRA capabilities vary across plants, it is expected that plant procedures will need to incorporate the plant-specific PRA attributes to make this generic guidance plant-specific. Regardless of PRA capabilities, the risk assessment is based on evaluation of the following risk hazards: internal events at full power; fire events; seismic events; other external events (such as tornadoes); and shutdown events.

The PRA model must be of sufficient scope and quality to adequately assess potential risk impacts of STI risk changes. In support of this, the PRA model shall have been evaluated against NRC Regulatory Guide (RG) 1.200, Revision 1 (Reference 3). This RG addresses the use of the ASME PRA standard (Reference 4) and the NEI PRA peer review process (Reference 5) for evaluating PRA technical adequacy. The RG specifically addresses the need to evaluate important assumptions that relate to key modeling uncertainties (such as reactor coolant pump seal models, common cause failure methods, success path determinations, human reliability assumptions, etc.). Further, the RG addresses the need to evaluate parameter uncertainties and demonstrate that calculated risk metrics (e.g., CDF and LERF) represent mean values. The identified "Gaps" to Capability Category II requirements from the endorsed PRA standards in the RG and the identified key sources of uncertainty serve as inputs to identifying appropriate sensitivity cases in Addendum 5 of this procedure.

At a minimum, the PRA must model severe accident scenarios resulting from internal initiating events occurring at full power operation. Beyond this, the other risk hazards are addressed by one or more of the following:

- An integrated model that incorporates one or more of these risk hazards.
- A separate model for a particular hazard (e.g., a Fire PRA).
- A qualitative evaluation for any hazard that is not modeled.
- For hazards that are modeled but where the component(s) being evaluated is not explicitly modeled, a bounding analysis or a qualitative evaluation.

For STI quantitative risk evaluations, the overall impact of a specific proposed change to surveillance frequency is assessed and compared to the quantitative risk acceptance guidelines of RG 1.174. Two types of effects on CDF and LERF are considered: the first effect involves the total or aggregate risk impact for all PRA events for each individual surveillance frequency change; the second effect involves the cumulative risk impact from previous SFCP surveillance frequency changes plus the current one under consideration.

Reference 1 describes a 20-step process for risk-informed SFCP implementation and control at nuclear power plants. These steps are illustrated in Figures 1, 2, and 3 of Reference 1. This procedure focuses on those portions of the process that are directly related to the PRA risk assessment activities. These are Steps 8 through 12 and 14 of the Reference 1 process (Step 13 is simply the consideration of a revised STI, which re-initiates the risk evaluation process).

2.2 DA Process Overview

Several reviews and evaluations are performed in the SFCP DA process, which are summarized as follows:

- Surveillance test history of the components and system associated with the STI change:
    - Review surveillance test history of affected components and system.
    - Review sufficient ST history to include approximately 100 performances. For example, for a two train quarterly surveillance at a two unit Plant, this is satisfied by a review period of approximately 6 years.
    - For STs that do not have at least 100 performances or may not have data reasonably available far enough back, review all retrievable test history.
    - Identify any pertinent information or insights regarding plant modifications, component changes, or changes in test methods implemented that provide a supporting basis justifying why any prior failures are no longer applicable or cannot recur.

- Performance history of the components and system associated with the STI change:
  - Review the preventive maintenance (PM) items that are associated with the components listed in the STI change. This review includes documentation of the following:
    - *The types of PMs performed and their periodicity*
    - *PMs that test any of the same characteristics or functions that the surveillance does*
    - *PMs that can identify degraded conditions before it affects the surveillance*
    - *Adverse trends identified by PMs and, if any, what the impact is on the surveillance. For this aspect, review associated history for the past five years.*
    - *A conclusion stating whether or not the PM review imposes any constraints on the extension*
  - Review the corrective maintenance (CM) items that are associated with the components listed in the STI change. Review associated CM history for the past five years at a minimum. Longer periods may be used if significant component history issues exist. This review includes documentation of the following:
    - *The failure history of the components associated with the surveillance*
    - *A conclusion indicating whether the CM history imposes any constraints on the STI change*
  - Identify the current Maintenance Rule status for the associated system and identify any Maintenance Rule (a)(1) performance history for the associated components.
  - Review the above data for trends of equipment performance issues. The review should focus on the amount and significance of equipment performance issues found.
  - Past industry and plant-specific experience with the functions affected by the STI change: Search for past industry and site-specific operating plant experience issues relevant to the proposed STI change by reviewing data sources such as EPIX, NRC website, documents (Generic Letters, NUREGs, etc.), and other relevant sources.
  - Vendor-specified maintenance frequency: Review vendor recommendations including testing recommendations relevant to the proposed STI change.
- Test intervals specified in applicable industry codes and standards:
  - Review the committed version of industry codes and/or standards to determine if any specific STI is specified therein.
  - If a more current code or standard exists compared to the committed revision, review the more current version for additional insights that may pertain to the proposed STI change. However, there is no explicit obligation to comply with the newer code or standard.
  - Any deviations from STIs specified in applicable industry codes and standards currently committed to in the plant licensing basis are reviewed and documented consistent with the other deterministic considerations within Section 6.5. The basis for any such deviations are documented, up to and including, if applicable, a change to the commitment in accordance with the Station's commitment change process. Any other deviations from applicable industry codes and standards should be documented.
- Impact of an SSC in an adverse or harsh environment:

- Consult with the {Environmental Qualification (EQ) coordinator or program manager} to determine if any impacts are created against site EQ reports for the SSCs associated with the proposed STI change.
- Identify the environmental conditions under which the SSC is normally exposed. If these conditions are considered harsh, evaluate whether extending the STI would result in an adverse impact (i.e., delay in identifying an SSC failure or degradation).

- Benefits of detection at an early stage of potential mechanisms and degradations that can lead to common cause failures:
  - Review SSCs associated with the proposed STI change for potential time-based failure mechanisms such that extending the STI may limit the ability to detect a level of degradation. Considerations include:
    - *chemical degradation of lubricating oil.*
    - *formation of rust films.*
    - *settlement of dust in areas that could increase friction.*
    - *unusual wearing patterns.*
    - *any data that could only be collected from the surveillance and trended to indicate an imminent failure.*
  - Consult the cognizant {component specialist, system engineer, program manager or a PRA representative} for assistance in identifying possible mechanisms and degradations of SSCs associated with the proposed STI change.
- The degree to which the surveillance provides a conditioning exercise to maintain equipment operability:
  - Consider the effect of fewer conditioning exercises from the proposed STI change (if proposed interval is an extension from current interval). Some conditioning exercises aid in maintaining equipment functionality. Examples include lubrication of bearings and electrical contact wiping (cleaning) of built up oxidation.
  - Review vendor manuals and recommendations to determine what credit, if any, that periodic testing provides in terms of conditioning.
  - If there is a conditioning benefit, then identify if any PMs, typical plant evolutions, or other testing activities are conducted more frequently than the proposed STI change and provide the same benefit.
- The existence of alternate testing of SSCs affected by the STI change:
  - Identify any existing alternate testing of SSCs associated with the STI change. Note that alternate testing need not necessarily be other surveillance testing, but could include checks or tests such as those that may be performed during PM activities.
  - If SSCs associated with the proposed STI change are tested as often as or more frequently than the current STI through other methods or tests, this consideration supports the proposed interval change from a qualitative and reliability perspective.
  - If the only test that exercises the affected SSCs associated with the proposed STI change is the proposed STI itself, then no alternate testing exists and this aspect does not provide any mitigating justification for the proposed STI change.
- Verify that assumptions in the plant licensing basis would not be invalidated when performing the surveillance at the maximum interval limit for the proposed STI change:

- Review the plant licensing basis (e.g., {Updated Final Safety Analysis Report}, Technical Specifications Bases, etc.) for any assumptions, including any instrument drift assumptions, related to the STI being proposed for change.
- Consider whether or not the assumptions would be invalidated at the maximum STI limit (i.e., the proposed STI plus the grace period, as defined in the Station's Surveillance Program.
- Consider impact of STI change on {instrument uncertainty and setpoint methodology calculations} used in the safety analysis.
- Consider if the proposed adjustment to the STI will require a change in the acceptance criteria (if proposed interval is an extension from current interval).
- The as-left acceptance criteria should factor in the potential for additional drift over any extended interval including any new uncertainties in the new drift value.
- If the acceptance criteria review deems that more stringent acceptance criteria is required, document this result and recommend a more conservative acceptance criteria in the STRIDE.

- Unavailability Review:
  - Perform a review of system/train unavailability associated with the SSCs utilized in the proposed STI change, if supporting Maintenance Rule data exists.
  - For systems whose actual unavailability is tracked by the Maintenance Rule, compare the actual unavailability performance values for the system/train to established site Maintenance Rule performance criteria values.
- Review the Mitigating Systems Performance Index (MSPI) and consider the impact, if any, of the STI increase on the MSPI.
- Review the Nuclear Electric Insurance Limited (NEIL) requirements contained in the applicable NEIL Loss Control Manual to identify if the proposed STI would result in not meeting a NEIL test interval requirement.
- Other deterministic considerations not specifically detailed above may be performed as applicable to provide additional insight into the evaluation of the proposed STI change.
- For each of the deterministic considerations identified in the DA, the associated assessments, results, and individual conclusions as to the acceptability of the STI change are documented in the STRIDE.
- Document the consolidated deterministic recommendation based on all insights drawn from the DA.

2.3 IDE Process

The SFCP STRIDE IDE process is outlined in this section. It is important to note that the tasks described below are to be performed using each station's site-specific empirical data obtained during the performance of surveillance tests for the specified monitoring period (typically 5 years). The product will be an engineering evaluation that determines whether or not the proposed STI extension will significantly affect the "drift" term used in the associated instrument uncertainty calculations to a 95/95 acceptance criterion. The IDE process is summarized as follows:

- For simple instrument loops, obtain the following empirical data for all of the instruments or instrument channels (loops) in the scope of the ST during the specified monitoring period:

- Unit designator
- Date of ST performance
- Instrument or channel unique number or designator
- As-found calibration value
- As-left calibration value
- Determine if any adjustment was performed.

- Instrument loops come in a variety of configurations. Some are simple such as a pressure switch that has contacts that provide actuation. Some are more complex consisting of a transmitter, signal conditioning and a bistable that provides actuation. The above sequence is satisfactory for simple loops but is not adequate for loops that are more complex. The appropriate sequence for more complex loops would be as follows, for each drift-sensitive device in the loop up to the actuating device (bistable):
  - Unit designator
  - Date of ST performance
  - Instrument or channel unique number or designator
  - As-found calibration values, typically for 5 points
  - As-left calibration values, typically for 5 points
  - Determine if any adjustment was performed.
- Calculate the instrument drift by subtracting the as-found actuation value of each ST from the as-left data of the previous ST. This difference is assumed to be the instrument drift.
- Since the drift is considered a random term, the differences are summed using the square-root-sum-of-the-squares methodology for all STs performed in the maximum interval (proposed STI plus the applicable grace period). Standard ISA-67.04 (Reference 6) provides guidelines for analyzing instrument calibration data to a 95/95 acceptance criterion. The analysis should be done consistent with the methods described in that standard.
- Repeat this calculation for all maximum intervals starting with the end of the monitoring period and going back to the beginning of the monitoring period. In general, sufficient data should be retrieved to develop approximately 100 data points (AF-AL) for each device.
- Average the results of the above calculations to determine the average drift over the maximum interval for each instrument or channel. Standard ISA-67.04 (Reference 6) provides guidelines for analyzing instrument calibration data. The analysis should be done consistent with the methods described in that standard. The methods described in the standard involve more than averaging.
- Compare the maximum average drift to the drift term used in the instrument uncertainty calculation.
- If the maximum average drift is the same or lower than the drift term used in the instrument uncertainty calculation, document the conclusion that the proposed STI is acceptable because it does not increase the assumed instrument uncertainty.
- If the maximum average drift is greater than the drift term used in the instrument uncertainty calculation, re-perform the above tasks using a smaller STI increase, subject to obtaining prior approval from the Program Manager. Frequently, the values determined for instrument drift are

not significantly time dependent. The method described above may not be successful in achieving a satisfactory STI. Review of the setpoint determination is usually successful in developing an analysis that will support the desired STI.

- Document the engineering evaluation and conclusion. The evaluation shall include the data used to perform the calculations and/or the appropriate references.

2.4 Catawba Results

The following six subsystems in the Catawba 7300 RPS and ESFAS functions were analyzed for the subsystems were analyzed for the PRA, DA and IDE portions of the STRIDE process:

- Boron Dilution Mitigation System (BDMS)
- Containment Purge Control System (CPCS)
- Nuclear Instrumentation System (NIS)
- Non-Overpower Delta Temperature Parameters(Non-OPDT)
- Overpower Delta Temperature functions (OPDT)
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Results for each subsystem were presented in a STRIDE analysis report including the PRA, DA and IDE portions. For the IDE portion, 31 analyses were performed to address the as-found, as-left plant specific drift for the past 5 years and most passed for the extension. In some cases, review against the setpoint calculation of record and expansion of the drift allowance in the calculation was required. In a few cases, specific modules were identified for replacement. Duke support from the Risk Informed Applications and Safety Analysis Groups were integral to the review and incorporation of the results into the plant configuration management program.

3 CONCLUSION

An overview of the TSTF-425 (industry Initiative 5B) SFCP STRIDE development processes, with a focus on IDE, has been presented in this paper. Experience has shown that the TSTF-425 (industry Initiative 5B) SFCP is one of the least complex of the endorsed risk-informed programs to implement at nuclear power plants, and it has significant potential benefit. For example, for the 68 STRIDEs the authors of this paper have completed for the industry to date, the associated power plant staffs have estimated that they will save over 12,110 person-hours of effort per year, or over 178 person-hours per year per STRIDE, on average. Conservatively, this equates to a combined potential savings of over $605,000.00 per year, or over $8,900.00 per year per STRIDE, on average. As one can see then, if each of these plants has a significant number of years remaining prior to the end of its license period, the potential total savings is very substantial. However, the authors are confident that this estimate of benefit to the plants, while significant, is actually quite low, as it is based solely on savings associated with predicted reductions in labor effort to perform the target surveillance tests. For example, there are also additional potential savings associated with reductions in plant refueling outage critical path time related to implemented STRIDEs. Taken collectively, the estimated reactor unit outage critical path time savings associated with the STRIDEs developed by the authors of this paper is 22.7 critical path hours per year. If we conservatively assume an average plant outage hour replacement power cost of approximately $400,000.00 per day for implementing plants (depends, of course, on a number of complex factors such as load dispatch strategies and specific electricity regional market power pricing and contracts for the implementing plants), the average annual replacement power cost savings is equivalent to $378,333.33 per year over the remainder of plant life.

Therefore, taken together, these two sources of SFCP savings represent a total estimated savings of over $1,000,000.00 per year over the remainder of plant life. Additionally, the authors of this paper are confident that the program savings discussed above are significantly underestimated, because there are other, as yet un-quantified, benefits associated with implementation of the STRIDEs developed by the authors of this paper and associated plant staffs. These benefits include, but are not limited to, the following:

- Reduced Frequency of Surveillance Test-Induced Reactor Trips, Plant Transient Forced Power Reductions, and Safety System Actuations
- Reduced Frequency of Potential Events Leading to Undesirable Steam Generator Chemistry Control
- Reduced Wear and Tear on Standby Safety Systems, Such as Emergency Diesel Generators
- Reduced Unavailability of Safety-Related and Safety-Significant Equipment Associated Directly with Surveillance Testing
- Improved Plant Resource Planning and Scheduling Flexibility, Including Enhanced Outage Planning and Scheduling Management
- Reduction in occupational exposures supporting ALARA programs
- Reduced Frequency of Human Errors Associated with Surveillance Testing
- Reduced Average Annual Material Costs Associated with Surveillance Testing
- Reduced Average Annual Contractor Costs Associated with Surveillance Testing
- Reduced Effort and Resource Requirements Associated with Surveillance Test Planning, Scheduling, Coordination, Documentation, Review, Approval, and Record Archiving

The authors of this paper are confident that rigorous assessment and crediting of these and other additional program benefits could effectively more than double the average annual estimated value of the SFCP to the implementing plants.

4 REFERENCES

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