Westinghouse Non-Proprietary Class 3

Westinghouse Energy Systems

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WCAP-13964
Revision 1
SG-94-02-004

Commonwealth Edison Company
Byron and Braidwood Units 1 and 2
Increased SGTP/Reduced TDF/PMTC
Analysis Program
Engineering/Licensing Report

March 1994

Revision 1

T. J. Gerlowski
B. E. Rarig

Westinghouse Electric Corporation
Nuclear Technology Division
P.O. Box 355
Pittsburgh, Pa. 15230

BYRON/BRAIDWOOD SGTP/TDF/PMTC LICENSING REPORT

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1.0 INTRODUCTION

1.1 Purpose

The purpose of the Steam Generator Tube Plugging/Thermal Design Flow Reduction/Positive Moderator Temperature Coefficient (SGTP/TDF/PMTC) Analysis Program is to perform the analyses and evaluations needed to verify that Byron and Braidwood Units 1 and 2 are functionally and structurally capable of continued reliable and safe operation with:

1. The tubes in the steam generators plugged to the most limiting plugging level of:

    a. a maximum plugging level of 15% in any steam generator, or

    b. a plugging level that results in the reduction of the Reactor Coolant System (RCS) loop flow rate to the Thermal Design Flow (TDF) limit.

2. Reduction in the TDF limit from 94,400 gpm per loop to 89,700 gpm per loop.

3. Incorporation in the design and safety analyses of a PMTC of +7 pcm/°F.

4. Boron concentration increase in the Refueling Water Storage Tank to a range of 2300 ppm to 2500 ppm, and in the accumulators to a range of 2200 ppm to 2400 ppm.

5. Incorporation of loop flow asymmetry of up to 5% in the analyses and evaluations in which RCS flow rates are important. (One loop may have flow up to 5% above or below the TDF of 89,700 gpm, depending on the conservative direction for each analysis.)

6. Increased Main Steam Safety Valve (MSSV) lift setpoint tolerance to ±5%.

1.2 Background

The TDF limit is a conservatively low design parameter that is used in the thermal-hydraulic design of the RCS and a variety of system, component and safety analyses. The TDF limit is selected to be conservatively low with respect to the actual RCS flow rate so that flow margin is available over that assumed in the design and analysis of the Nuclear Steam Supply System (NSSS), the fuel, and the NSSS components. Once operational data is obtained and the amount of flow margin is known, this margin can be subsequently used to accommodate reductions in RCS flow due to changes such as steam generator tube plugging. The currently analyzed TDF flow rate for Byron and Braidwood Units 1 and 2 is 94,400 gpm per loop (377,600 gpm total), and will be reduced to 89,700 gpm per loop (358,800 gpm total).

The new TDF value (358,800 gpm total flow) was chosen to ensure approximately 5% DNB margin after the SGTP/TDF/PMTC work scope was completed. The SGTP level which corresponds to this TDF was determined to be 24%. Since the objective of the SGTP/TDF/PMTC Program is to support the SGTP level of 15% (to match the LOCA analysis limit), the analyses and evaluations performed as part of the SGTP/TDF/PMTC effort utilized SGTP levels (as high as achievable) up to 24%. Each section in this report notes the actual SGTP level used in that analysis. Overall, the SGTP level of 15% is limiting since it is the lowest SGTP level used in any of the analyses.

In 1987, Commonwealth Edison Company and Westinghouse performed a T_{Hot} Reduction Program for Byron and Braidwood Units 1 and 2 to justify operation within a temperature range defined by a maximum T_{Hot} of 618.4°F and a minimum T_{Cold} of 538.2°F. The TDF was maintained at 94,400 gpm per loop. Also included was a SGTP level of up to 10% of the tubes plugged in any steam generator, not to exceed the plugging level that would reduce the RCS flow rate below the TDF limit. The results of the T_{Hot} Reduction Program are presented in WCAP-11388, "Byron Units 1 and 2 and Braidwood Units 1 and 2 T_{Hot} Reduction Program," (Reference 1.0-1).

The current LOCA analysis basis for Byron/Braidwood allows a 15% maximum tube plugging level in any one steam generator. This is now the limiting design basis tube plugging criteria for Byron/Braidwood as a result of the SGTP/TDF/PMTC Analysis Program documented herein.

The present Byron/Braidwood MTC Technical Specifications require the MTC to be zero or negative at all times while the reactor is critical. This requirement is overly restrictive, since a small positive MTC at reduced power levels would have a minor effect on the FSAR accident analyses. Safety analysis justification of a positive MTC supports reductions in fuel cycle costs by reducing burnable poison inventory, particularly for long cycles which require a large number of burnable poisons to control MTC at the beginning of cycle life.

The proposed MTC Technical Specification change allows a positive MTC below 70% of nominal rated thermal power at BOL. At 70% power the coefficient begins to decrease linearly to 0 pcm/°F at 100% nominal rated thermal power. A power level dependent MTC was chosen to minimize the effect of the Technical Specification change on postulated accidents at high power levels. Moreover, as the power level is raised, the average coolant temperature becomes higher as allowed by the plant programmed average temperature controller, tending to make the MTC more negative. Also, boron concentration can be reduced as xenon builds into the core. Thus, there is less need to allow a positive MTC as full power is approached. As fuel burnup is achieved, boron is further reduced and the MTC will eventually become negative over the entire operating power range.

Those accidents which are found to be sensitive to positive or near-zero MTC are analyzed. These transients are discussed specifically with respect to positive MTC. In general, these accidents are limited to transients which cause the reactor coolant temperature to increase. Accidents which do not require analysis for a positive MTC include those resulting in excessive heat removal from the reactor coolant system. In these cases a large negative MTC assumption produces more limiting results. Also unaffected are those transients for which heatup effects following reactor trip are not sensitive to the MTC.

The Refueling Water Storage Tank (RWST) and the accumulator boron concentration range are increased to allow for the implementation of a positive MTC and longer core cycle. The only non-LOCA safety analyses in which boron from the RWST or accumulators is credited or assumed to be present are those in which the Safety Injection System (SIS) is actuated.

1.3 Scope

Westinghouse scope for this program includes the NSSS safety, system, and component analyses and evaluations necessary to increase the allowable steam generator tube plugging level for Byron and Braidwood to the 15% limit. Due to the method used to define the RCS parameters (see Section 2.1.1), the actual SGTP limit supported by the reduction in TDF is 24%, and this value is included in the analyses where possible. The program encompasses all aspects of the NSSS design and operation which are impacted by the increased steam generator tube plugging, reduced TDF limit, loop to loop RCS flow asymmetry, and the positive moderator temperature coefficient. The scope of the program includes the NSSS safety analyses, the functional capability of the systems for normal and abnormal plant operations, and the mechanical design of the NSSS components and structures. A detailed technical description of the integrated Steam Generator Tube Plugging Analysis Program may be found in Reference 1.0-2.

The analyses and evaluations included in this program were performed in accordance with the following criteria.

1. Safety analyses included in the program were performed to FSAR quality standards, using current NRC approved analytical techniques, and were evaluated in accordance with the criteria and standards that apply to the current Byron and Braidwood Units 1 and 2 operating license.

2. NSSS system and component designs were evaluated in accordance with the regulatory requirements, codes, and standards which were applicable to Byron and Braidwood Units 1 and 2 when the plants were originally licensed plus any subsequent criteria specifically applied to Byron and Braidwood Units 1 and 2 by the NRC.

The SGTP/TDF/PMTC Program for Byron and Braidwood Units 1 and 2 is based on the following assumptions and design inputs:

- The analyses and evaluations assume a reactor coolant TDF of 89,700 gpm per loop. The Minimum Measured Flow value is based on the RCS flow measurement uncertainty value to be supplied by CECo. In addition, a maximum flow deviation (below the TDF) of 5% is assumed.

- The analyses and evaluations assume the temperature boundaries established as part of the T_{Hot} Reduction Program, WCAP-11388. ($T_{Hot} \leq 618.4°F$, $T_{Cold} \geq 538.2°F$) Also, the Economic Generation Control (EGC) temperature window of $\pm$4°F deadband on T_{avg} will be utilized.

- NSSS performance parameters will be determined which will minimize the impact of the tube plugging allowance on steam pressure beyond the steam pressure reduction accounted for in WCAP-11388 (P_{steam} greater than 827 psia).

- The analyses and evaluations will be based on the fuel loading anticipated for the appropriate cycles for Byron and Braidwood, Units 1 and 2.

- The uncertainties (RCS pressure, temperature, power, and flow) specified for the program are: (Reference 1.0-3 and 1.0-4)

RCS Pressure Control	+/- 33.4 psi
Temperature (Including Rod Control) (1.14°F bias added to analysis temperature)	+/- 7.60°F
Reactor Power (Daily Calorimetric)	+/- 1.83% RTP
RCS Flow (Pr ion Calorimetric)	+/- 3.5% Flow

- An increase in the Main Steam Safety Valve (MSSV) setpoint tolerance to 5%. (The licensing basis setpoint tolerance will not be changed from the current value of $\pm$1% at this time.)

The revised design parameters and the results of the evaluations and analyses performed during the program are presented in the following sections.

References

1.0-1 WCAP-11388, "Byron Units 1 and 2 and Braidwood Units 1 and 2 T_{Hot} Reduction Program," May 1987.

1.0-2 Westinghouse letter CAE-93-191, CCE-93-211, "S/G Tube Plugging and Thermal Design Flow Reduction Analysis Program," B. S. Humphries to D. E. St. Clair, July 28, 1993.

1.0-3 Commonwealth Edison Company letter NFS:PSS:93-305, "Byron/Braidwood RTDP Uncertainties," E. H. Young to T. J. Gerlowski, October 29, 1993.

1.0-4 Operating Parameter Uncertainties for the Byron/Braidwood Revised Thermal Design Procedure, Revision 0, dated December 20, 1993.

2.0 POWER CAPABILITY PARAMETER EVALUATION

2.1 Power Capability Parameters

Byron and Braidwood Units 1 and 2 are designed and licensed to operate at an NSSS power level of 3425 MWt with a Thermal Design Flow (TDF) of 94,400 gpm per loop (377,600 gpm total flow). The original NSSS power capability parameters associated with this design condition are shown in the first column of Table 2.1-1.

The power capability parameters for Byron and Braidwood Units 1 and 2 were revised in 1987 as part of the T_{Hot} Reduction Program. (Reference 2.0-1) The power capability parameters resulting from this analysis are shown in the second column of Table 2.1-1. A comparison of the revised power capability parameters with the original parameters shows that the parameters which changed were the RCS temperatures and steam generator (secondary side) parameters. Steam pressure, steam temperature and steam flow decreased as a result of the decrease in steam generator heat transfer surface area that accompanied the increase in the allowable steam generator tube plugging level to the 10% limit, as well as the reduced driving force (RCS temperature). The RCS temperatures also changed due to reducing the value of T_{Hot}. The value of TDF remained at 94,400 gpm per loop for the T_{Hot} Reduction Program.

The power capability parameters used in this program reflect a level of 24% steam generator tube plugging, a Thermal Design Flow reduction to 89,700 gpm per loop, and the temperature range supported by the T_{Hot} Reduction Program. These parameters are shown in the third, fourth, fifth, and sixth columns of Table 2.1-1. The third and sixth columns are based on the existing range of T_{avg}, 588.4°F to 569.1°F. The fourth and fifth columns are based on preserving the maximum T_{Hot} and minimum T_{Cold} values of 618.4°F and 538.2°F, respectively. This T_{Hot} - T_{Cold} range was supported by the 1987 T_{Hot} Reduction Program and remains limiting for this SGTP/TDF/PMTC Program. In this way, columns four and five represent the temperature boundaries for the current analyses. Since the RCS Thermal Design Flow was reduced, the RCS temperatures reflect the change in heat load on the reactor coolant. T_{Hot} increased and T_{Cold} decreased slightly due to the lower RCS flow through the core. The T_{avg} range remained the same as that used in the 1987 program. The steam temperature, pressure, and flowrate also decreased due to the increased steam generator tube plugging, and its attendant reduction in heat transfer area. As noted in Table 2.1-1, the steam generator conditions were assumed to remain the same as the T_{Hot} reduction Program for analysis considerations. Based on current plant operating conditions, there is expected to be operating margin to accommodate the anticipated steam pressure reduction caused by the higher plugging level and lower RCS flowrates. Since a steam pressure reduction below 827 psia would effect a change in the design transients necessary to envelop the design, the decision was made to analytically limit the steam pressure reduction to 827 psia and use actual plant operating margin to maintain steam pressure above the steam pressure limit. Consequently, the analyzed parameters now cover up to 24% steam generator tube plugging, reduced Thermal Design Flow (89,700 gpm per loop), and loop-to-loop flow asymmetry of up to 5%.

TABLE 2.1-1
Byron and Braidwood Units 1 and 2
NSSS Power Capability Parameters for SGTP/TDF/PMTC

Primary Parameters (@ 100% Power)	Original Design	T_{Hot} Reduction	Nominal T_{avg} 588.4 °F	Maximum T_{Hot} 618.4 °F	Minimum T_{Cold} 538.2 °F	Minimum T_{avg} 569.1 °F
NSSS Power, MWt	3425	3425	3425	3425	3425	3425
Reactor Power, MWt	3411	3411	3411	3411	3411	3411
Thermal Design Flow, gpm per loop	94,400	94,400	89,700	89,700	89,700	89,700
Core Bypass Fraction, %	5.8	5.8	6.3	6.3	6.3	6.3
RCS Pressure, psia	2250	2250	2250	2250	2250	2250
RCS Temperatures, °F	-	-	-	-	-	-
Core Outlet	621.7	603.5	623.7	622.2	607.0	605.6
Vessel Outlet	618.4	600.0	619.9	618.4	603.0	601.6
Vessel/Core Inlet	558.4	538.2	556.9	555.2	538.2	536.6
Core Average	591.8	572.2	592.2	590.6	574.2	572.7
Vessel Average	588.4	569.1	588.4	586.8	570.6	569.1
SG Outlet	558.1	537.9	556.6	554.9	537.9	536.3
Zero Load Temperature, °F	557.0	557.0	557.0	557.0	557.0	557.0
Steam Pressure, psia	990	827	899	885	751	740

Primary Parameters (@ 100% Power)	Original Design	T_{Hot} Reduction	Nominal T_{avg} 588.4 °F	Maximum T_{Hot} 618.4 °F	Minimum T_{Cold} 538.2 °F	Minimum T_{avg} 569.1 °F
Steam Temperature, °F	543.3	522.1	531.8	529.9	511.1	509.3
Steam Flow, Million lbm/hr	15.13	15.03	15.07	15.06	14.99	14.98
FW Temperature, °F	440.0	440.0	440.0	440.0	440.0	440.0

Notes:

(1) Plant operations are limited to a maximum T_{Hot} = 618.4 °F, a minimum T_{Cold} = 538.2 °F, and a minimum steam pressure of 827 psia.

2.2 Best Estimate Steam Generator Tube Plugging Levels

The Byron and Braidwood Units 1 and 2 Steam Generator Tube Plugging Analysis Program has been structured to analyze and evaluate both a limiting plugging level (15% maximum in any one steam generator based on LOCA analyses and selected component evaluations) and a bounding 24% plugging level (non-LOCA and all other evaluations) which corresponds to the estimated plugging level that maintains RCS flow at the reduced Thermal Design Flow (TDF) limit of 89,700 gpm per loop (358,800 gpm total flow), including consideration of flow measurement uncertainty as applicable. Also included in the program is the allowance of loop-to-loop flow asymmetry of up to 5%.

2.2.1 RCS Flow Measurement Uncertainty

For Byron and Braidwood Units 1 and 2, the appropriate flow measurement uncertainty (precision calorimetric) is 3.5% (Reference 2.0-2). This value of flow measurement uncertainty is a conservative value that has been endorsed by the NRC for use in plants that do not have a plant-specific calculation of flow measurement uncertainty.

2.2.2 Overall Steam Generator Tube Plugging Levels

(For purposes of illustrating the overall and per loop steam generator tube plugging levels and the relationship between plugging level and RCS flow measurements, the following two sections utilize data from Byron Unit 1.)

The prediction of best estimate overall steam generator tube plugging levels for Byron Unit 1 considers both the existing plugging levels plus the additional plugging levels that can be achieved based on the present RCS flow margin. The results of the most recent flow measurement tests show that total flow for Byron Unit 1 was measured as 395,467 gpm. The overall steam generator tube plugging levels that existed for Byron Unit 1 at the time of these tests was 4.6%, based on 4578 tubes per steam generator. The most recent RCS flow measurement test results and the existing steam generator tube plugging levels at the time of these tests are summarized on Table 2.2-1.

To obtain percent flow margin, the flow margin is divided by the TDF. To obtain the best estimate additional plugging level, the percent flow margin is multiplied by 4.35 which is based on the relationship that plugging approximately 4.35% of the steam generator tubes results in a 1% reduction in RCS flow. This best estimate relationship between RCS flow and steam generator tube plugging applies for tube plugging levels up to approximately 20%. The tube plugging levels calculated in this manner based on existing flow margin are termed the best estimate additional tube plugging levels. To obtain the best estimate final tube plugging levels, the existing tube plugging levels are added to the additional tube plugging levels.

Based on the measurement uncertainty of 3.5%, the best estimate final plugging level is calculated to be approximately 33.7% for Byron Unit 1. The calculation of this best estimate plugging level is summarized in Table 2.2-1. Best estimate additional plugging level for Byron Unit 1 is approximately 29.1%, also based on a 3.5% uncertainty and the existing tube plugging level of 4.6%.

2.2.3 Steam Generator Tube Plugging Levels on a Per Loop Basis

As discussed in Section 2.2, the Byron and Braidwood Units 1 and 2 stéam generators are permitted to be plugged to the 15% limit or to the plugging level that reduces RCS flow to the TDF limit of 89,700 gpm per loop, including consideration of flow measurement uncertainty as applicable. Consequently, the prediction of tube plugging level for each steam generator is based on the plugging levels that exist in each steam generator plus the best estimate prediction of additional plugging that can be achieved based on the present RCS flow margin in the associated loop. The results of the most recent flow measurement tests on a per loop basis and a summary of the existing steam generator tube plugging levels per steam generator are presented in Table 2.2-2.

The calculation of best estimate additional and final plugging levels for each steam generator based on present RCS flow margin is summarized on Table 2.2-2 for Byron Unit 1.

References

2.0-1 WCAP-11388, "Byron Units 1 and 2 and Braidwood Units 1 and 2 T_{Hot} Reduction Program," May 1987.

2.0-2 Commonwealth Edison Company letter NFS:PSS:93-305, "Byron/Braidwood RTDP Uncertainties," E. H. Young to T. J. Gerlowski, October 29, 1993.

TABLE 2.2-1

Byron Unit 1
RCS Total Flow and
Overall Steam Generator Tube Plugging Level

Measured Flow, gpm	395,467 (1)
Overall Steam Generator Tube Plugging Level, Number of Tubes	847 (1)
Overall Steam Generator Tube Plugging Level, %	4.6 (1)
Minimum Measured Flow, gpm	371,400 (2)
Thermal Design Flow, gpm	358,800
RCS Total Flow Margin, gpm	24,067
RCS Total Flow Margin, %	6.7
Best Estimate Additional Tube Plugging Level, %	29.1
Best Estimate Final Tube Plugging Level, %	33.7

Notes:

(1) Tube plugging level and measured flow following the (B1R05 outage in Spring 1993).

(2) Flow measurement uncertainty = 3.5%.

TABLE 2.2-2

Byron Unit 1
RCS Loop Flows and
Steam Generator Tube Plugging Levels

Measured Flow, gpm (1)	99,389	96,887	98,955	100,236
Steam Generator Tube Plugging Level, Number of Tubes (1)	186	299	243	119
Steam Generator Tube Plugging Level, Per Cent (1)	4.1	6.5	5.3	2.6
Minimum Measured Flow, gpm (2)	92,850	92,850	92,850	92,850
Thermal Design Flow, gpm	89,700	89,700	89,700	89,700
Flow Margin, gpm	6539	4037	6105	7386
Flow Margin, %	7.3	4 .5	6.8	8.2
Best Estimate Additional Plugging Level, %	31.7	19.6	29.6	35.7
Best Estimate Final Plugging Level, %	35.8	26.1	34.9	38.3

Notes:

(1) Tube plugging level and measured flow following the (B1R05 outage in Spring 1993).

(2) Flow measurement uncertainty = 3.5%.

3.0 NSSS SYSTEMS EVALUATION

3.1 NSSS Fluid Systems

3.1.1 Evaluation of PMTC/RWST Boron Concentration Increase

3.1.1.1 Background

The design basis for Byron and Braidwood Units 1 and 2 includes the ability to achieve cold shutdown (Mode 5) conditions from operating conditions (Modes 1 and 2) using the minimum Technical Specification boron concentrations and levels in the Boric Acid Storage Tank (BAST) or the Refueling Water Storage Tank (RWST) without the need to replenish the boric acid source. The guidance regarding the necessary changes in soluble boron concentration required to accomplish the transition from operating conditions to cold shutdown conditions is based upon the assumption that near EOL conditions are limiting with regard to boration duty. However, the assumption that near EOL conditions is most limiting may not be valid for some extended fuel cycles with high critical concentrations, high discharge burnup cycles, or for those plants with boron-dependent variable shutdown margin requirements or a change to PMTC designs.

Therefore, with the current setpoints in the Byron/Braidwood Technical Specifications, the boration requirements necessary to achieve long term cold shutdown conditions may exceed the available boration system capability. The purpose of this evaluation is to assess the boration requirements associated with the implementation of PMTC to the available boration system capabilities.

In accordance with the commitments made in the Byron/Braidwood UFSAR, the CVCS must provide a reactivity control source independent of the control rods (e.g., boric acid). Therefore, it is also a design requirement for Byron/Braidwood to borate the RCS from hot full power (HFP) to 1% shutdown in 90 minutes. Thus, emergency boration via the BAST must also be confirmed as part of this evaluation.

The boration system capability is a function of both the boration system setpoints and the initial condition concentration. Therefore, it is necessary to evaluate the boration requirements of a given cycle design or other related modifications in terms of both minimum credible critical concentration (precondition) and maximum corresponding shutdown concentration.

Finally, the containment spray and sump pH must be reevaluated for any change in concentration of any of the boration systems.

In summary, the performance capabilities of the Chemical Volume and Control (CVCS), Containment Spray System (CSS), and Boron Recycle System (BRS) are dependent on the RCS operating boron concentrations and changes in boron concentrations to satisfy core shutdown margin requirements. The performance capabilities of the CVCS, CSS, and SIS are dependent upon the boron concentration range of the RWST. The following sections summarize the evaluations of the NSSS fluid systems in support of the PMTC upgrade, and the resulting RCS concentration changes, as well as the proposed increase in RWST boron concentration to 2300-2500 ppm.

3.1.1.2 Systems Impact due to Increase in RWST Boron Concentration Range to 2300-2500 ppm

This section will describe the results of the evaluation of shutdown requirements for both the RWST and the Boric Acid Storage Tank (BAST).

RWST Volumes Required to Achieve Core Shutdown Margin

Mode 5/6 Boration Capability: Technical Specification Limiting Condition for Operation (LCO) 3.1.2.5 and Corresponding Bases 3/4.1.2 require that, as an alternative to the BAST, the RWST must contain sufficient volume to provide a shutdown margin as defined by Technical Specification 3.1.1.2 after xenon decay and cooldown from 200°F to 140°F. The Technical Specifications currently specify a contained borated water level in the RWST of 9.0%, which ensures an available volume of greater than or equal to 38,740 gallons.

The estimate of RCS boron concentration changes over core life to meet the core shutdown margin requirements related to this Technical Specification were provided in Reference 3.0-2. Based upon this input, only 2264 gallons of 2300 ppm boric acid solution are required from the RWST to perform the negative reactivity change and makeup for RCS inventory shrinkage during the Mode 5 cooldown from 200°F to 140°F. For conservatism, 68°F is used as the final temperature, since Mode 5 can extend beyond 140°F. Therefore, the current Technical Specification contained borated water level of 9% (38,740 gal.) is more than adequate to provide the boration capability required by the Technical Specification.

Mode 1-4 Boration Capability: Technical Specification LCO 3.1.2.6 and corresponding Bases 3/4.1.2 require that, as an alternative to the BAST, the RWST contain sufficient volume to provide a shutdown margin as specified in Technical Specification 3.1.1.1 after xenon decay and cooldown to 200°F. The Technical Specifications currently specify a contained borated water level in the RWST of 89%, which ensures an available volume of greater than or equal to 395,000 gallons.

Based upon the required boron concentration changes over core life resulting from the PMTC core design provided in Reference 3.0-2, only 54014 gallons of 2300 ppm boric acid solution from the RWST are required to perform the reactivity change from Mode 1 to Modes 4 or 5, and make up for the RCS inventory shrinkage from 557°F to 200°F. Therefore, the current Technical Specification contained borated water level (dictated by Safety Injection requirements) of 89% (395,000 gal.) is more than adequate to provide boration capability as required by the Technical Specifications.

Safety Injection Accumulator Boron Concentration Range

Upon inspection of the Byron/Braidwood Technical Specifications, it has been determined that the boron concentration in the accumulators matches the RWST boron concentration minus 100 ppm to account for inadvertent dilution or small accumulator volume control operations using makeup water. Therefore, in accordance with the increase in RWST boron concentration range, the boron concentration range in the accumulators is changed to 2200-2400 ppm. The containment spray and sump pH calculation are performed consistent with this concentration range.

Containment Spray Fluid pH / Containment Sump Solution pH

The Containment Spray System serves the functions of post-accident containment pressure reduction, radiological consequences reduction, and sump pH adjustment. Sump pH adjustment to an alkaline condition is necessary to prevent chloride-induced stress corrosion cracking of stainless steel components and to improve iodine retention during post-accident recirculation.

To accomplish sump pH adjustment, NaOH is added via an educator to the containment spray fluid delivered from the RWST during the injection phase. Changing the boron concentration of the educator motive fluid from the RWST impacts the pH of the fluid delivered to containment. The resulting post-accident sump pH is primarily dependent upon the volumes and concentrations of the RCS, RWST, and the accumulators, as well as the pH of the spray fluid. Of these components, the RWST has the greatest impact on the resulting post-accident sump pH range, since it has the largest volume of borated water delivered to the sump. Therefore, in order to properly evaluate the effect of an increase in the boron concentration range in the RWST, the minimum spray and sump pH values must be reassessed for adequacy. It is important to note that the maximum containment spray pH and sump pH requirements will not be challenged by the modifications evaluated herein, as increased boron will reduce pH.

Minimum Containment Sump pH: The minimum containment sump pH values were evaluated based upon the following volumes and maximum boron concentrations:

SOURCE	MAX. BORON CONC.	VOLUME
RCS	1930 ppm	91,366 gal
RWST	2500 ppm	444,850 gal

Accumulator	2400 ppm	28,862 gal

Based upon these values and a minimum required sump pH of 8.5, the Spray Additive Tank (SAT) allowable minimum NaOH concentration is 29.922 weight percent. The SAT volume is 3074 gallons. Technical Specification 3.6.2.2 currently reports the minimum allowable SAT concentration to be 30 wt. %. Due to the small amount of resulting margin, Westinghouse recommends that a change be made to increase the margin in the SAT concentration. This change could be accomplished in several ways, including a recalculation of the SAT level setpoints, an analysis to increase the minimum NaOH concentration in the SAT, or an analysis to reduce the minimum allowable sump pH. It has been determined that a reduction in the minimum allowable containment sump pH would be the most benign of these alternatives.

Using the volumes and concentrations described above, it was determined that reduction of the minimum containment sump pH (Technical Specification Bases 3/4.1.2, 3/4.5.5, and 3/4.6.2.2) to 8.0 would correspond to a minimum required NaOH concentration in the SAT of approximately 23.37 wt. %. In this case, sufficient margin exists in the minimum containment sump pH. Section 6.8 contains a detailed discussion of the reduction of minimum containment sump pH to 8.0.

Minimum Containment Spray pH: An increase in the boron concentration in the RWST will result in a reduced containment spray pH, as the RWST contents are used as the Spray Additive Tank educator motive fluid. The minimum containment spray pH is limited to 8.5 based upon the EQ limit.

Using test acceptance values provided by Commonwealth Edison (Reference 3.0-1) for both maximum CS pump flow and minimum SAT educator flow, the minimum containment spray pH was calculated to be 9.2. This is well above the minimum of 8.5.

3.1.1.3 Systems Impact Due to Increase in RCS Operating Boron Concentrations and Core Shutdown Boron Concentrations

The following systems/components are affected by the increase in RCS boron concentrations due to the PMTC analysis:

- BAST Volumes Required to Achieve Core Shutdown Margin
- CVCS Emergency Boration in Modes 1-4
- CVCS Boration Flow to Compensate for Xenon Decay

<u>BAST Volumes Required to Achieve Core Shutdown Margin</u>

Mode 5/6 Boration Capability: As with the requirements stated above for the RWST, Technical Specification LCO 3.1.2.5 and the corresponding Bases 3/4.1.2 require that the

BAST contain sufficient volume to provide required shutdown margin as defined by Technical Specification 3.1.1.2 after xenon decay and cooldown from 200°F to 140°F. The Technical Specifications currently specify a BAST level of 7% which ensures an available volume of greater than or equal to 2652 gallons of 7000 ppm boric acid solution.

The estimates of RCS boron concentration changes over core life to meet the core shutdown margin requirements related to this technical specification were provided in Reference 3.0-2. Based upon this input, Westinghouse has determined that only 740 gallons of 7000 ppm boric acid solution are required from the BAST to perform the negative reactivity change and makeup for RCS inventory shrinkage during the Mode 5 cooldown from 200°F to 140°F. For conservatism, 68°F is used as the final temperature, since Mode 5 can extend beyond 140°F. Therefore, the current Technical Specification contained borated water level of 7% (2652 gal.) is more than adequate to provide the boration capability required by the Technical Specifications.

Mode 1-4 Boration Capability: Similar to the requirements for the RWST, Technical Specification LCO 3.1.2.6 and corresponding Bases 3/4.1.2 require that the BAST contain sufficient volume to provide a shutdown margin as specified in Technical Specification 3.1.1.1 after xenon decay and cooldown to 200°F. The Technical Specifications currently specify a contained borated water level in the BAST of 40%, which ensures an available volume of greater than or equal to 15,780 gallons of 7000 ppm boric acid solution.

Based upon the required boron concentration changes as a result of the PMTC core design provided in Reference 3.0-2, Westinghouse has determined that only 13487 gallons of 7000 ppm boric acid solution from the BAST are required to perform the reactivity change from Mode 1 to Modes 4 or 5, and make up for the RCS inventory shrinkage from 557°F to 200°F. Therefore, the current Technical Specification contained borated water level of 40% (15,780 gal.) is adequate to provide boration capability as required by the Technical Specifications.

<u>Emergency Boration in Modes 1-4</u>

Technical Specification 3.1.1.1 states that should the shutdown margin fall below the specified limit, the CVCS must be capable of providing boration at greater than or equal to 30 gpm of 7000 ppm boric acid solution. In addition, in Section 9.3, the UFSAR reports that the rate of boration with only one boric acid transfer pump (BATP) in operation, must be capable of taking the reactor to 1% shutdown in the hot condition from full power using only this boration source (no rods) within 90 minutes.

Westinghouse has determined that the Byron/Braidwood CVCS continues to meet the specified performance requirements and licensing commitments (per GDC 26) for the proposed design changes.

CVCS Boration Flow to Compensate for Xenon Decay

Section 9.3 of the UFSAR further states that, via a single BATP, the CVCS is able to compensate for the xenon decay below the equilibrium level after shutdown condition is achieved (all rods out) within an additional 90 minutes, even though xenon decay below equilibrium will not occur until approximately 25 hours after shutdown condition is reached. Section 9.3 of the UFSAR also states that, as an alternative to the emergency boration flow path, charging to the RCS can be continued via the RCP seal injection at approximately 5 gpm per pump (20 gpm total) in approximately 3.5 hours.

Based upon an emergency boration flow of 55 gpm, Westinghouse has confirmed that UFSAR commitment to compensate for xenon decay below equilibrium using a single BATP within 90 minutes is achievable.

However, based upon a seal injection flow of 20 gpm, the commitment to compensate for xenon decay from equilibrium following shutdown using the RCP seal injection in 3.5 hours is unachievable by a very small amount. Using the revised core design data provided in Reference 3.0-2, approximately 4300 gallons of 7000 ppm boric acid solution is required to compensate for xenon decay from equilibrium following shutdown. At 20 gpm, only 4200 gallons is able to be delivered in 3.5 hours. It is important to note, however, that this is not a safety concern, as the xenon decay from equilibrium does not even begin until approximately 25 hours after shutdown.

3.1.1.4 Conclusions

Westinghouse has concluded that the Byron and Braidwood CVCS, SIS, BRS, and CSS, as designed, are capable of supporting the proposed RCS and RWST boron concentration changes by only revising the Technical Specifications and Updated Final Safety Analysis Report as described above. This conclusion is based upon evaluation of the Technical Specification requirements, equipment qualification requirements and UFSAR commitments for shutdown margin, minimum containment spray pH, SIS Accumulator boron concentration, and emergency boration requirements.

3.1.2 Evaluation of SGTP

Westinghouse has evaluated the impact of Steam Generator Tube Plugging level of 24% and a reduced Thermal Design Flow of 89,700 gpm on the Westinghouse scope NSSS fluid systems at Byron and Braidwood including the RCS, CVCS, RHRS, and SIS. Although the increase in SGTP and the reduction in TDF does not affect the design functions of the NSSS fluid systems, these modifications do have the potential to impact the performance of these systems. Consequently, evaluations were performed to assess the impact of the modifications on system performance. The temperature ranges established for the 1987 T_{Hot} Reduction Program were assumed to remain applicable for this evaluation (maximum T_{Hot} of 618.4°F and minimum T_{Cold} of 538.2°F). Operating pressure of the RCS is not impacted by the increase in SGTP or reduction in TDF, and remains at 2250 psia.

3.1.2.1 Reactor Coolant System

The following Byron/Braidwood Reactor Coolant System design calculations were reviewed for impact due to increased SGTP and reduced TDF:

- Pressurizer Surge Line Performance
- Pressurizer Safety Valve Discharge Line Performance
- Pressurizer Spray Performance
- RTD Bypass Line Performance
- Pressurizer Relief Tank Sizing and Level Setpoints

As a result of this review, the performance areas that are potentially affected by the increase in SGTP or the decrease in TDF were determined to be the pressurizer spray performance and the RTD Bypass flow rate / delay time. The evaluations of these performance areas are described below.

Pressurizer Spray System

The Byron and Braidwood Pressurizer Spray System is designed to extract coolant from the RCS cold legs and into the spray nozzle of the pressurizer in order to maintain pressurizer pressure below the power operated relief valve setpoint for small step loads (up to 10% from full power) and to provide a small continuous flow which is required to maintain the pressurizer spray piping at a temperature above a minimum value (approximately 500 °F), and to equilibrate coolant chemistry in the pressurizer and RCS loop piping.

The pressure drop available to overcome piping losses is the difference between the total available differential pressure and the sum of the spray piping, nozzle and elevation pressure drops. The cold leg spray scoop configuration allows the velocity head to contribute to the total pressurizer spray driving force.

Although the reduction in the thermal design flow to 89,700 gpm directly affects the performance of the Pressurizer Spray System, sufficient pressure drop still exists to facilitate the pressurizer spray performance to the design capacity of 900 gpm.

RTD Bypass Line Performance

The narrow range RCS hot and cold leg temperatures at Byron and Braidwood are measured in each reactor coolant loop via resistance temperature detectors (RTDs) located in bypass manifolds. A small stream of coolant is extracted from both the hot leg and cold leg of each loop and directed through the manifold holding the RTDs. After exiting the RTD manifolds, the hot leg and cold leg flow is combined and returned to the crossover leg of the same loop. The cold leg bypass line contains a flow restrictor which is sized to provide approximately equal hot leg and cold leg transport delay times, ensuring that the delay time in both the hot and cold leg bypass lines remain below 2 seconds.

The driving force for the hot leg bypass line is the pressure drop across the primary side of the steam generator. This pressure drop will increase as a result of the increase in tube plugging level. Consequently, the hot leg bypass line flow will increase as steam generator tube plugging level and steam generator ΔP increase.

Similarly, the driving force for the cold leg bypass line flow is the developed head of the reactor coolant pump. Since the steam generator ΔP increases as SGTP level increases, RCS flow will decrease, forcing the reactor coolant pump (RCP) to run back on its performance curve. The RCP will therefore operate at a point on its performance curve that results in a higher developed head, resulting in an increase in cold leg RTD bypass flow.

The net effect of the increase in SGTP level of up to 24% on both the hot and cold leg RTD bypass flow rates is an increase in both flow rates. Consequently, the delay time in the narrow range RCS temperature measurement will remain the same or decrease.

3.1.2.2 Chemical and Volume Control System

The operation of the Chemical and Volume Control System was reviewed to assess the impact of NSSS operation at a steam generator tube plugging level of 24% and a reduced thermal design flow of 89,700 gpm. It was determined that the change in RCS loop pressure differential was small and will have no significant impact on the CVCS letdown, excess letdown, charging, or seal injection flow rates. The hot leg and cold leg temperatures that were evaluated as part of the 1987 T_{Hot} Reduction Program were reflected in the current SGTP analysis. Based upon the T_{Hot} reduction evaluation, these temperatures (maximum T_{Hot} of 618.4°F and minimum T_{Cold} of 538.2°F) do not effect the operation of the CVCS heat exchangers.

3.1.2.3 Residual Heat Removal System

The operation of the Residual Heat Removal System (RHRS) was reviewed to assess the impact of NSSS operation at a steam generator tube plugging level of 24% and a reduced thermal design flow of 89,700 gpm. It was determined that, while the change in RCS loop pressure differential has the potential to impact the operation of the RHRS during hot or cold shutdown conditions, the change is small and therefore, will not significantly affect RHRS flow rates. The RCS temperatures evaluated in the 1987 T_{Hot} Reduction Program (maximum T_{Hot} of 618.4°F and minimum T_{Cold} of 538.2°F) remain applicable for this evaluation and have been determined to have no effect on the operation of the RHRS. Therefore, the performance of the RHRS as presently analyzed remains valid for a SGTP level of 24% and a reduced thermal design flow of 89,700 gpm.

3.1.2.4 Safety Injection System

The performance of the Safety Injection System (SIS) is dependent upon the ability of the charging pumps, safety injection pumps, and residual heat removal pumps to deliver sufficient emergency core coolant to the RCS during accident conditions. The operation of the (SIS) was reviewed to assess the impact on its operation at a SGTP level of 24% and a reduced TDF of 89,700 gpm. Because the performance of the SI, Charging, and RHR pumps is not impacted by the increase in SGTP or by the reduced TDF, it was determined that the operation of the Safety Injection System is unaffected.

3.1.2.5 Component Cooling Water System

The Byron and Braidwood Component Cooling Water System (CCWS) removes heat from the following equipment:

- Reactor Coolant Pumps (thermal barrier heat exchanger and upper/lower bearing oil coolers)
- Residual Heat Removal Pumps (seal cooler)
- Letdown Heat Exchanger
- Excess Letdown Heat Exchanger
- Seal Water Heat Exchanger
- Spent Fuel Pit Heat Exchanger
- Residual Heat Exchangers
- Sample Heat Exchangers
- Recycle Evaporator Package
- Waste Gas Compressors

As stated above, the increase in SGTP and reduction in TDF does not affect the operation of the CVCS, RHRS, or SIS. Similarly, the operation of the components listed above that are cooled by the CCWS remain unaffected by this modification. Therefore, increased SGTP to 24% and a reduced TDF of 89,700 gpm have no impact on the operation of the CCWS.

3.1.2.6 NSSS Fluid Systems Summary

As a result of the assessment of the Westinghouse-supplied NSSS fluid systems presented above, it was concluded that these systems will continue to perform as designed at a Steam Generator Tube Plugging level of 24% and a reduced thermal design flow of 89,700 gpm. While the RCS differential pressure will be reduced, the reduction has either insignificant impact or no impact on the Westinghouse-supplied NSSS fluid systems.

3.2 Reactor Protection System

As a result of the analysis and evaluation efforts performed for the Byron and Braidwood SGTP/TDF/PMTC Analysis Program, changes to the plant Technical Specifications are appropriate. The increase in allowable steam generator tube plugging level and the thermal design flow reduction do not in themselves require changes to any Reactor Protection System (RPS) setpoints. However, the analyses presented in this submittal were performed using the Revised Thermal Design Procedure in order to gain DNB margin. This change in analysis methodology provided additional margin which could be used to increase the overpower and overtemperature Delta-T (OPΔT and OTΔT) reactor trip setpoints. The setpoints and bases for Reactor Protection System/ESF changes are provided in Table 3.0-1. See Section 6.0 for the safety analysis and evaluations of the design basis events which confirm the adequacy of the new Reactor Protection System setpoints to satisfy the analysis acceptance criteria. Additional Technical Specification changes not directly related to the Reactor Protection System/ESF are tabulated, and their bases are provided, in the Technical Specification Change Licensing Submittal.

3.3 Reactor Control Systems

Control system performance evaluations involve assessment of margin to reactor trip/ESF actuation and plant stability in response to operational transients. Margin to trip is determined by demonstrating appropriate margin to actuation setpoints in response to operational transients. By design, these operational transients should not cause a reactor trip or ESF actuation in order to terminate the transient at stable conditions. Plant stability is determined by reviewing control system actuations such as rod motion and steam dump in response to operational transients and verifying that no excessive cycling occurs.

Plant response is sensitive to changes in the nominal overtemperature ΔT and overpower ΔT reactor trip functions and nominal plant operating conditions which may be affected by increased steam generator tube plugging levels. Results of the safety analyses typically determine the need to change the reactor trip functions. In this program, the nominal K_1 and K_3 values in the Overtemperature ΔT equation have changed as a result of changes to the uncertainties applied to the various aspects of these functions.

Another significant change from the control systems design perspective is in the average temperature channel of the rod speed program. The rod speed program maintains the same minimum speed, maximum speed, and lockup, but changes the average temperature deadband from $\pm 1.5°F$ to $\pm 4.0°F$. Increasing this deadband can minimize excessive rod stepping when in an Economic Generation Control (EGC) mode of operation. Up to this time, when operating in EGC, the plants were forced to reduce the previously analyzed operating window by 2°F on the upper and lower end in order to compensate for the required increased deadband. This modification is justified on an individual basis by the fact that rod motion in response to a load rejection or step changes would be controlled by the power mismatch channel. Therefore, changes to the T_{avg} deviation channel temperature deadband would have no effect on the transient response.

However, since changes to the OTΔT and OPΔT equations have been defined which necessitates reanalysis, this increased temperature deadband has been included in the modelling to confirm margin to trip and plant stability with the resulting new setpoints.

Plant stability and margin to various reactor trip and ESF actuation setpoints in response to normal operational transients has been evaluated at both reduced and nominal operating temperatures, accounting for the revised SGTP/TDF/PMTC Program parameters. The following transients were analyzed to confirm adequate plant response:

- 10% step load increase from 90% power at reduced temperature
  - margin to low pressurizer pressure reactor trip
  - margin to low steamline pressure SI
  - margin to high nuclear flux reactor trip
  - stability

- 10% step load decrease from full power at reduced temperature
  - margin to OTΔT/OPΔT reactor trip
  - margin to PORV lift
  - stability

- 50% load rejection from full power at reduced and nominal temperature
  - margin to OTΔT/OPΔT reactor trip
  - margin to negative flux rate reactor trip
  - steam dump load rejection stability

- Reactor trip from full power at reduced and nominal temperature
  - margin to steam generator safety valve lift
  - plant cooldown without undershoot below no-load
  - margin to low pressurizer pressure SI
  - steam dump plant trip stability

- Turbine trip without reactor trip from 30% power
  - no pressurizer PORV lift

In all cases, adequate margin to actuation was demonstrated and stable plant response was predicted. Therefore, based on an overall review of the reactor control systems operation relative to the revised design parameters and experience on plants that have performed tube plugging, the performance of the various control systems will remain within their design envelopes and will not be adversely affected. There will be no degradation in the plant response to normal expected transients. These conclusions were reached based on a review of the results from LOFTRAN modelling of the various transients and hand calculations which determined both response stability and margin to the various actuation setpoints. Plant stability was determined primarily from reviewing the transient response of T_{avg}, rod steps and nuclear power, which are expected to attain equilibrium conditions following the transient without evidence of excessive cycling. Margin to the actuation setpoints was determined by comparing the minimum or maximum values attained during a transient (as appropriate) to the Technical Specification values and confirming that operational margin to these setpoints exists such that they would not be activated in response to the anticipated transient.

3.4 Low Temperature Overpressure Protection System

Increasing steam generator tube plugging reduces the RCS volume and heat transfer surface area in the steam generators. The effect that these changes have on the design basis heat injection and mass injection transients was evaluated to determine the continued validity of the PORV setpoints utilized in the Low Temperature Overpressure Protection System (LTOPS). A brief description of the analyses conducted for the mass injection and heat injection transients is described below.

For the mass injection transient, the basic relationship for setpoint/overshoot determination is:

$$\Delta P = \Delta P(ref)\ F(v)\ F(s)\ F(z)$$

where,

ΔP = setpoint overshoot
$\Delta P(ref)$ = mass injection rate function for a reference overshoot
$F(v)$ = RCS volume factor
$F(s)$ = relief valve setpoint factor
$F(z)$ = relief valve opening time factor

Only the F(v) term will be significantly affected by reduced SG tube volume resulting from increased SGTP. Smaller RCS volumes result in greater pressure increases for the mass injection transient. Given that the overshoot is equal to the Appendix G pressure limit minus the PORV setpoint ($\Delta P = P_G - SP$), with a higher overshoot and a constant Appendix G limit, it follows then that the new PORV setpoint must be lower. The new PORV setpoint is equal to the initial setpoint minus the initial overshoot adjusted for the RCS volume change. Using the worst case large setpoint overshoot (92 psi) combined with the smallest setpoint (455 psi pending for Braidwood 1 at 70°F) as the limiting case, the maximum reduction in the LTOPS setpoints is calculated to be 0.94%. This difference is judged to be sufficiently small so as to be absorbed within the conservatism inherent in the methodology used to generate the setpoints. Therefore, adjustment of the PORV LTOP setpoints to account for the effect of 15% SGTP is not necessary in order to maintain the appropriate level of protection against reactor vessel brittle fracture.

The consequence of increasing the steam generator tube plugging level, with respect to heat injection events, depends on the rate of reduction of heat transfer surface area relative to the rate of reduction of the RCS volume. It has been established that the effect of plugging steam generator tubes is to always result in reduced setpoint overpressures due to heat injection events. Therefore, the effect on the setpoints determined for the mass injection transient developed above is bounding.

Reference

3.0-1 CECo Test 2BVS 6.2.2.D-1, Rev. 1, approved 8/29/90, transmitted via FAX from Penny Reister, Commonwealth Edison Co. to Gary Brassart, Westinghouse, dated 11/10/93.

3.0-2 Letter CDE-93-242, "Byron/Braidwood BORDER for PMTC +7.0 pcm/°F," 11/3/93.

3.0-3 Letter CCE-87-138, "Westinghouse Review of Pre-Operational/Startup Tests," 10/20/87.

3.0-4 Not Used

3.0-5 Calculation RC&SGSS-C-486, "BORDER Code Verification," 3/23/90.

3.0-6 Letter FSE/FSDA-93-2098, "Byron/Braidwood Implementation and RWST Boron Concentration Increase," 1/26/93.

TABLE 3.0-1

Reactor Protection System/ESF Setpoints

Parameter	Value
K1, max	1.37
K2	0.0297
K3	0.00181
K4, max	1.072
K5 (for increasing T_{Avg})	0.02
K6 (for T_{Avg} > 588.4°F)	0.00245
ΔI Band	-24, +10
Positive Slope (Penalty)	4.11
Negative Slope (Penalty)	3.35

The above OPΔT and OTΔT setpoints were determined as a result of implementing the Revised Thermal Design Procedure (RTDP) in the increased SGTP/reduced TDF analyses. These values were calculated using NRC approved methods and were verified by transient analysis to protect the core thermal limits and prevent fuel center-line melting. Instrument uncertainty allowances have been accounted for in the setting of the Technical Specification values for K1 and K4. The OTΔT trip provides protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors (RTDs) and pressure is within the range between the Pressurizer High and Low Pressure trips. The OPΔT trip provides assurance of fuel integrity under all possible overpower conditions, limits the required range for OTΔT trip and provides a backup to the High Neutron Flux trip.

4.0 NSSS DESIGN TRANSIENTS EVALUATION

4.1 Design Transients

Based on the power capability parameters for 15% steam generator tube plugging, the currently applicable Byron/Braidwood Units 1 and 2 NSSS design transients established for the T_{Hot} Reduction Program in WCAP-11388 (Reference 4.0-1) remain bounding for increased steam generator tube plugging levels up to 15%. This conclusion is based on the fact that there were no changes to the maximum T_{Hot}, minimum T_{Cold}, or minimum steam pressure limits previously defined for the design transients in the T_{Hot} Reduction Program. Therefore, no new design transients need to be generated to support plant operation with up to 15% SGTP.

An increased tolerance of ±5% on the main steam safety valve setpoints was evaluated to confirm that no design transient is created which is more limiting than those currently applicable. Assuming a 5% reduction in the lowest MSSV setpoint plus a nominal blowdown of 3% would result in a setpoint of 1081 psig (1175 psig x 0.92). Saturation temperature corresponding to this pressure is 555.8°F. This temperature is not significantly below the Byron/Braidwood no-load design temperature of 557°F. Therefore, the resulting secondary-side transient associated with any plant cooldown initiated from nominal conditions would be considered to be within the currently analyzed temperature envelope.

The design transients assume a maximum steam pressure of 1236 psia which is equivalent to the steam generator design pressure +3%. The first bank of steam generator safety valves is nominally set at 1190 psia. Assuming a +5% tolerance on this value gives a maximum pressure of 1250 psia (1190 x 1.05). The effect of this small additional pressure increase is determined to be insignificant when considering the conservatism in the number of cycles assumed.

References

4.0-1 WCAP-11388, "Byron Units 1 and 2 and Braidwood Units 1 and 2 T_{Hot} Reduction Program," May 1987.

5.0 NSSS COMPONENTS EVALUATION

5.1 Reactor Vessel

The reactor vessel operating temperatures are covered by the work performed for the T_{Hot} Reduction Program (Reference 5.0-3). There are no new RCS design transients resulting from the 15% SGTP and no new reactor vessel/reactor internals interface loads that will be generated. Therefore, the SGTP/TDF/PMTC Program has no effect on the reactor vessel. Since the reactor vessel evaluation is based on the parameters shown in Table 2.1-1, this evaluation applies to SGTP up to 24%.

5.2 Reactor Internals

The reactor pressure vessel system consists of the reactor vessel, the reactor upper and lower internals assemblies, and the reactor core. Since these components are interdependent from a thermal-hydraulic and structural viewpoint, they were evaluated as a system. The reactor pressure vessel system is not directly impacted as a result of steam generator tube plugging. However, it is sensitive to variations in the reactor coolant system flowrate. Therefore, the reactor pressure vessel system was evaluated with respect to the reduction in the Thermal Design Flow.

New flows and pressure drops were calculated for the various flow paths within the reactor pressure vessel system. The results showed that the changes in pressure drops associated with the new design parameters are uniformly distributed throughout the reactor internals, and that the total pressure drop across the internals would decrease by an insignificant amount. Since the internals flow and pressure drop changes are not changed significantly by the new design parameters, detailed calculations of the effect on core bypass flow, hydraulic lift forces, flow induced vibration, and Rod Control Cluster Assembly (RCCA) rod drop times were not necessary.

The other aspect of the reactor vessel/internals assembly is to support the core and to direct flows within the vessel. While directing the primary flow through the core, the internals assembly also establishes secondary coolant flow paths for cooling the upper regions of the reactor vessel and for cooling the internals structural components. Some of the parameters influencing the mechanical design of the internals lower assembly are the pressure and temperature differentials across its component parts and the flow rate required to remove the heat generated within the structural components due to radiation (e.g., gamma heating). The variations in flowrate for the baffle-barrel region did not change significantly for the proposed RCS conditions and the reduced thermal design flow. Since there is no change in the original design transients/heat generation rates the reactor internals components, such as, lower support assembly, baffle plates, formers, core barrel, neutron panels, upper support plate, outlet nozzles, lower radial support, upper core plate alignment pins and core barrel, there will be no adverse impact on the structural response of these components for the proposed steam generator tube plugging and the corresponding reduced Thermal Design Flow.

The second result of a Thermal Design Flow reduction is to increase the temperature rise across the reactor vessel (i.e., hot leg temperature - cold leg temperature). For the approximate 5% Thermal Design Flow reduction included in the revised Byron/Braidwood Units 1 and 2 design parameters, the ΔT increases are bounded by the (maximum T_{Hot} of 618.4°F and minimum T_{Cold} of 538.2°F) evaluations performed earlier for the Byron/Braidwood plants as part of the T_{Hot} Reduction Program.

In summary, the evaluation of the reactor pressure vessel system demonstrated that there would be no adverse impact on the performance of the system by the proposed increased steam generator tube plugging (up to 24%) and the corresponding reduced Thermal Design Flow.

5.3 Reactor Coolant Pumps

5.3.1 Structural Evaluation

The structural design of the reactor coolant pumps utilizes as design inputs the power capability parameters for RCS normal operating temperatures (i.e., RCS hot leg temperature and cold leg temperature) and the NSSS design transients. As discussed in Sections 2.0 and 4.0, the RCS normal operating parameters and design transients do not change as a result of the increase in steam generator tube plugging level to either the 24% or the TDF limit. The reactor coolant pumps are also exposed to higher resistance due to the increase in allowable steam generator tube plugging level. The design and analyses of the reactor coolant pumps remain applicable for tube plugging levels up to either the 24% or the TDF limit. The hydraulic loads associated with operating at the higher resistance do not have any adverse effect on the pump internals.

5.3.2 Motor Evaluation

Revised loads have been calculated for the Byron and Braidwood Units 1 and 2 reactor coolant pump motors. The new loads have increased due to the revised performance estimates and the effects of the proposed tube plugging. The ability of the RCP motors to operate with these new loads is as follows:

1. Continuous operation at the new hot loop rating of 7040 HP.

   The revised load exceeds the nameplate rating of the motor slightly (by 40 HP). The change in stator winding temperature resulting from this increase will be insignificant (less than 1°C). A review of the original test data indicates that with the increased temperature rise included, the NEMA design limits for a Class B winding will not be exceeded. Therefore, continuous operation of the motors under hot loop conditions with the parameters shown in Table 2.1-1 is acceptable.

2. Operation at the new cold loop rating of 8920 HP.

   The revised load exceeds the nameplate rating of the motor by 2%. Analysis indicates that this increase will probably cause the cold loop temperature rise to exceed the NEMA guaranteed limit for a Class F winding (100°C) by about 2°C. Although the amount by which the limit is exceeded is small, it must be assumed that operation at full cold loop conditions will result in some accelerated thermal aging of the insulation. By design, the motors are intended to operate under full cold loop conditions for a maximum of 3000 hours. Exceeding the Class F limit by 2°C can be expected to accelerate the aging and reduce life by approximately 600 hours or about one month. This is not considered to be an excessive reduction. Therefore, operation at the revised cold loop load is considered acceptable.

3. Rotor winding temperatures during worst case starting scenario (maximum reverse flow, cold loop, 80% voltage with no voltage recovery) with the revised loads.

   The revised load torque curve is marginally more severe than the original. The increase in rotor cage winding temperature due to the increased load is small and the total winding temperature is well below the allowable limit. Therefore, starting under the worst case scenario is acceptable.

5.4 Control Rod Drive Mechanism

The power capability parameters have been reviewed. It has been determined that these conditions are bounded and evaluated previously for the T_{Hot} Reduction Program (Reference 5.0-3). The T_{Hot} Reduction Program analysis concluded that there was no impact on the conclusion of the project specific stress reports and that all specific requirements are met. Therefore, the design requirements for the Control Rod Drive Mechanism (CRDM) are still met for the parameters given in Table 2.1-1.

5.5 Pressurizer

The components of the Byron/Braidwood pressurizers have been evaluated to 15% SGTP and reduced TDF parameters. It was determined that the components of the pressurizer meet the ASME Code, Section III stress analysis and fatigue analysis requirement for the evaluated modes of operation.

5.6 Reactor Coolant Loop Piping and Primary Equipment Supports

The reactor coolant piping evaluations which were performed for the T_{Hot} Reduction Program remain applicable for the SGTP/TDF/PMTC Program. Refer to Section 6.6.3 for a discussion of the LOCA Blowdown and Reactor Vessel and Loop Forces.

5.7 Reactor Coolant Loop Stop Valves

The design parameters for the SGTP/TDF/PMTC Program were reviewed to determine the impact on the loop stop valves. The main loop stop valve evaluation found that the structural integrity and valve function are acceptable for the parameters shown in Table 2.1-1.

5.8 Steam Generators

5.8.1 Structural Integrity Evaluation

Structural evaluation of Byron/Braidwood, Units 1 and 2 steam generators for 15% SGTP limit with reduced TDF has been performed. The analysis demonstrated that the maximum stress intensities and fatigue usages at critical locations, such as U-Bend, in the steam generator do not exceed the allowable limits of the ASME Code.

5.8.2 Thermal-Hydraulic Evaluation

The factors governing the thermal-hydraulic performance of steam generators can be reduced to the thermal power and steam pressure. Other factors such as primary temperature, primary flow and plugging level are important only insofar as they affect the steam pressure. The present plugging program maintains the current power rating for all the units. The minimum steam pressure, therefore, represents the bounding condition for the evaluation. The T_{Hot} Reduction Program performed for the Byron and Braidwood Units evaluated a minimum steam pressure of 827 psia corresponding to a primary temperature reduction of 20°F. The present SGTP/TDF/PMTC Program maintains that same minimum steam pressure, and the evaluations performed for the T_{Hot} reduction are applicable to the present program (i.e., SGTP up to 24% and parameters as in Table 2.1-1).

Other Thermal-Hydraulic Characteristics

In addition to moisture carryover, several other parameters are indicators of acceptable performance. The most important of these parameters are circulation ratio, damping factor (the indicator for hydrodynamic stability) and steam generator mass. Experience has shown the change in these parameters with reduced steam pressure is generally small. For a pressure reduction from the present design value to the minimum 827 psia, all these parameters decrease. Mass decreases by less than 5% while circulation ratio and damping factor decrease by 5-15%. From a steam generator performance standpoint, the circulation ratio and mass changes are not significant. The damping factor remains negative indicating continued hydrodynamic stability but with reduced margin.

5.8.3 U-Bend Vibration Evaluation

U-bend fatigue evaluations were performed for all Byron and Braidwood units. For Byron Unit 1 and Braidwood Unit 1 a base study was completed for operation at the most limiting current operating condition for the two units. In addition, the evaluation was extended to cover future operating conditions which might result from primary temperature reduction or increased steam generator tube plugging. As discussed below, the minimum steam pressure for the SGTP/TDF/PMTC Program, 827 psia, is bounded by this evaluation.

The Model D5 steam generators in Byron Unit 2 and Braidwood Unit 2 use 405 stainless steel support plates. These plates have not exhibited susceptibility to corrosion and denting, a prerequisite for high cycle U-bend fatigue. This circumstance notwithstanding, denting was assumed at the top tube support and recommended operating limits for steam pressure at rated power were determined. The following shows these limits are not exceeded by the parameters given in Table 2.1-1.

Byron Unit 1 and Braidwood Unit 1

The U-bend evaluation report for these plants (Reference 5.0-1) recommended that two tubes be removed from service based on the current operating conditions. In addition, Section 10 of that report described a one dimensional relative stability ratio methodology to extend the base study to other operating conditions. This section showed how the increase in power (steam flow) or the decrease in steam pressure resulting from plugging or primary temperature reduction would increase the stability ratio for the U-bend tubes. The increase is quantified by the relative stability ratio (RSR).

Figure 10-1 of Reference 5.0-1 shows the relationship of RSR to steam flow and steam pressure. At the current rating (steam flow = 3.78×10^6 lbm/hr), RSR is a function only of steam pressure. Selecting the minimum steam pressure (827 psia) less 50 psi, determined by the report as representative of the measurement uncertainty, the figure is entered at 777 psia. At this steam pressure, the relative stability ratio will remain below 1.20. Table 10-2 shows the RSR multiplier at which specific tubes will require preventive action. If all tubes in this table, with limiting RSR values of 1.20 or less, are removed from service, then U-bend fatigue will not be a concern at the limiting operating conditions for Byron Unit 1 and Braidwood Unit 1.

From Table 10-1 of Reference 5.0-1, the tubes requiring preventive action at the SGTP/TDF/PMTC analysis conditions, including the ones specified for current operating conditions, are listed in Table 5.0-1 with the corresponding relative stability ratio.

Byron Unit 2 and Braidwood Unit 2

A prerequisite for U-bend fatigue, denting at the top tube support, is not present at Byron Unit 2 and Braidwood Unit 2. Even so, Reference 5.0-2 provides a preliminary evaluation to define operating limits for these plants assuming this prerequisite is present. The operating limits are defined in terms of acceptable ranges of power (steam flow) and steam pressure such that no tubes will require preventive action. The regions of acceptable operation are displayed on Figures 6-2 and 6-3 of Reference 5.0-2. These figures show that, at the current rating (steam flow = 3.78×10^6 lbm/hr), the minimum acceptable steam pressure is well below the 777 psia determined above, including measurement uncertainty. Byron Unit 2 and Braidwood Unit 2 will, therefore, have no U-bend vibration concern at the conditions in Table 2.1-1.

5.9 Auxiliary Equipment

The new performance capability parameters were compared to the auxiliary equipment transients. The evaluation concluded that the auxiliary transients are either unchanged by the SGTP/TDF/PMTC Program or still bounding. Therefore, there is no effect on the auxiliary equipment provided by Westinghouse contained in the CVCS, RHRS, or SIS.

References

5.0-1 "Byron Unit 1 and Braidwood Unit 1 Evaluation for Tube Vibration Induced Fatigue," WCAP-12608, October 1990.

5.0-2 "Preliminary Evaluation of the Byron Unit 2 and Braidwood Unit 2 Steam Generator Tube Bundle Conditions with Respect to Tube Vibration Induced Fatigue," SG-91-01-030, October 1990.

5.0-3 WCAP-11388, "Byron Units 1 and 2 and Braidwood Units 1 and 2 T_{Hot} Reduction Program," May 1987.

TABLE 5.0-1

Tubes Requiring Preventive Action at 15% Tube Plugging Conditions

	RSR	S/G	Tube
Byron 1:	1.0 (Current)	C	R12C8
	1.117	C	R11C4
Braidwood 1:	1.0 (Current)	B	R12C5
	1.141	B	R12C3

6.0 SAFETY ANALYSIS AND EVALUATION

6.1 Background

The Thermal Design Flow is a conservatively low design parameter that is used in the thermal-hydraulic design of the Reactor Coolant System and a variety of systems, components, and safety analyses. The TDF limit is selected to be conservatively low with respect to the actual RCS flow rate so that flow margin is available over that assumed in the design and analysis of the Nuclear Steam Supply System and the NSSS components. Once operational data is obtained and the amount of flow margin is known, this margin can be subsequently used to accommodate reductions in RCS flow due to plant changes, such as increased Steam Generator Tube Plugging. The Byron/Braidwood units are currently licensed to operate at a NSSS power level of 3,425 MWt, with a RCS Thermal Design Flow of 94,400 gpm per loop, as described the Byron/Braidwood Stations UFSAR Table 5.1-1. Plant operation is limited to a minimum steam pressure of 827 psia, maximum T_{Hot} of 618.4°F, and minimum T_{Cold} of 538.2°F (see Section 2.1).

Analyses have been performed to support a SGTP level of 15 percent. The TDF has been reduced to incorporate maximum SGTP while maintaining adequate Departure from Nucleate Boiling (DNB) margin. The performance capability parameters, presented in Section 2.1, reflect 24% SGTP, which corresponds to the TDF of 89,700 gpm/loop. The effect on the NSSS of an increased steam generator tube plugging level will primarily be a decrease in the primary to secondary side heat transfer area, resulting in reduced secondary side steam pressure and temperature. Also, there will be a slight increase in the pressure drop through the steam generator tubes and a small decrease in the RCS active volume.

To support the SGTP/TDF/PMTC Program, Westinghouse has been requested to provide a safety evaluation to determine whether the revised analysis assumptions associated with the SGTP/TDF/PMTC Program involves an unreviewed safety question.

6.2 Licensing Approach and Scope

Title 10 of the Code of Federal Regulations, Part 50, Section 59 (10 CFR 50.59) allows the holder of a license, authorizing operation of a nuclear power facility, the capacity to investigate and disposition change to the normal plant configuration. The proposed SGTP/TDF/PMTC Program represents change to the normal plant configuration. Prior Nuclear Regulatory Commission (NRC) approval is not required to implement a change provided that the change does not involve an unreviewed safety question or result in a change to the plant technical specifications. However, it is the obligation of the licensee to maintain a record of the change or modifications to the facility, to the extent that such changes impact the FSAR. The code further stipulates that these records shall include a written safety evaluation that provides the basis for the determination that the SGTP/TDF/PMTC Program does not involve an unreviewed safety question. It is the purpose of this document to support the requirement for a written safety evaluation.

The safety evaluation has been prepared pursuant to the requirements of 10CFR50.59. The scope is limited to an evaluation for operation of Byron/Braidwood at increased SGTP up to 15 % maximum tube plugging level or up to the plugging level corresponding to the RCS TDF Limit, whichever is lower, centering on any effects such operation may have on existing systems and components or any unreviewed safety questions that may be identified.

6.3 Systems and Components Evaluation

The following sections present the systems and components evaluation for the SGTP/TDF/PMTC Program for Byron/Braidwood units. From these evaluations, it has been confirmed that the revised parameters associated with the increased SGTP do not affect the Nuclear Steam Supply or Balance of Plant Systems and components.

6.3.1 NSSS Fluid Systems

Westinghouse has evaluated the impact of Steam Generator Tube Plugging level of 24% and a reduced Thermal Design Flow of 89,700 gpm on the Westinghouse scope NSSS Fluid Systems at Byron and Braidwood including the RCS, CVCS, RHRS, and SIS. Although the increase in SGTP and the reduction in TDF does not affect the design functions of the NSSS fluid systems, these modifications do have the potential to impact the performance of these systems. Consequently, these evaluations were performed to assess the impact of the modifications on system performance. It is important to note that the temperature ranges established for the 1987 T_{Hot} reduction program were assumed to remain applicable for this evaluation (maximum T_{Hot} of 618.4°F and minimum T_{Cold} of 538.2°F). Operating pressure of the RCS is not impacted by the increase in SGTP or reduction in TDF and remains at 2250 psia.

As a result of the assessment of the Westinghouse-supplied NSSS fluid systems, it was concluded that these systems will continue to perform as designed at a steam generator tube plugging level of 24% and a reduced TDF of 89,700 gpm. While the RCS differential pressure will be reduced due to this modification, the reduction has either insignificant impact or no impact on the Westinghouse-supplied NSSS fluid systems.

6.3.2 Auxiliary Equipment

The new performance capability parameters were compared to the auxiliary equipment transients. The evaluation concluded that the auxiliary transients are either unchanged by the SGTP/TDF/PMTC Program or still bounding. Therefore, there is no effect on the auxiliary equipment provided by Westinghouse contained in the CVCS, RHRS, or SIS.

6.3.3 Reactor Pressure Vessel

The reactor vessel operating temperatures are covered by the previous work performed for the T_{Hot} Reduction Program. There are no new RCS design transients resulting from the 15% SGTP and no new reactor vessel/reactor internals interface loads that will be generated. Therefore, there is no impact of the increased SGTP/TDF reduction on the reactor vessel.

6.3.4 Reactor Coolant Pump and Motor

The Reactor Coolant Pumps (RCPs) were evaluated for to the 15% SGTP and reduced conditions. It was determined that the RCP structural integrity and RCP coastdown are acceptable for the proposed conditions. The RCP hydraulic evaluation showed no adverse effects on the safety-related components of the pumps.

The performance capability parameters were used to generate the worst case loading for the RCP motors at the Byron and Braidwood sites with 24% steam generator tube plugging. Analysis has demonstrated that the Byron/Braidwood motors are acceptable for operation with the proposed 15% SGTP/TDF reduction, based on the evaluation of the evaluation of the performance capability parameters, which reflect 24% tube plugging.

6.3.5 Reactor Coolant Loop Stop Valves

The design parameters for the SGTP/TDF/PMTC Program were reviewed to determine the impact on the loop stop valves. The main loop stop valve evaluation found that the structural integrity and valve function are acceptable for the SGTP/TDF/PMTC Program conditions.

6.3.6 Control Rod Drive Mechanism

The performance capability parameters have been reviewed. It has been determined that these conditions are bounded and evaluated previously under the T_{Hot} Reduction Program. The T_{Hot} Reduction Program analysis concluded that there was no impact on the conclusion of the project specific stress reports and that all specific requirements are met. Therefore, the design requirements for the Control Rod Drive Mechanism (CRDM) are still met for the SGTP/TDF/PMTC Program conditions.

6.3.7 Pressurizer

The components of the Byron/Braidwood pressurizers have been evaluated to 15% SGTP and reduced TDF parameters. It was determined that the components of the pressurizer meet the ASME Code, Section III stress analysis and fatigue analysis requirement for all modes of operation.

6.3.8 Steam Generators

6.3.8.1 Thermal-Hydraulic Evaluation

The factors governing the thermal hydraulic performance of the steam generators can be reduced to the thermal power and steam pressure. Other factors such as primary temperature, primary flow, and plugging level are only important insofar as they affect steam pressure. The present plugging program maintains the current power rating for all the units. The minimum steam pressure, therefore, represents the bounding condition for the evaluation. The T_{Hot} Reduction Program performed for the Byron and Braidwood Units evaluated a minimum steam pressure of 827 psia corresponding to a primary temperature reduction of 20°F. The present 15% steam generator tube plugging effort maintains the same minimum steam pressure and the evaluations performed for the T_{Hot} Reduction Program are applicable to the present program.

6.3.8.2 Other Thermal Hydraulic Characteristics

In addition to moisture carryover, several other parameters are indicators of acceptable performance. The most important of these parameters are circulation ratio, damping factor (the indicator for hydrodynamic stability) and steam generator mass. The steam generator evaluation has shown that these parameters remain acceptable for the 15 SGTP/TDF reduction program.

6.3.8.3 Structural Analysis

Structural evaluation of Byron/Braidwood, Units 1 and 2 steam generators for 15% SGTP limit with reduced TDF has been performed. The analysis demonstrated that the maximum stress intensities and fatigue usages at critical locations, such as U-Bend, in the steam generator do not exceed the allowable limits of the ASME Code.

6.3.9 Nuclear Fuel

An evaluation of the effects of the increased steam generator tube plugging level (24%), reduced Thermal Design Flow limit (89,700 gpm per loop), and positive moderator temperature coefficient (+7 pcm/°F) on the fuel design was performed with respect to the core design, the thermal-hydraulic design and fuel rod performance.

The licensing basis for the increased SGTP and decreased TDF limit includes the licensing of a Positive Moderator Temperature Coefficient Technical Specification. The impact of PMTC on Core Design is an increase in the soluble boron concentrations required for various normal and transient core operating conditions. The effects of the higher boron concentrations are addressed in the LOCA and non-LOCA analyses, while the boron duty requirements are addressed in fluid systems analysis. Thermal-hydraulic analyses were performed to support the reduction in Minimum Measured Flow from 390,400 gpm to 366,000 gpm. All of the current FSAR thermal-hydraulic design criteria are satisfied. The minimum measured flow (MMF) values used in the T/H analyses conservatively bound the MMF in the technical specification.

Based on the DNB uncertainty factors, Revised Thermal Design Procedure design limit DNB ratio values were determined such that there is at least a 95 percent probability at a 95 percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and operational transients and during transient conditions arising from faults of moderate frequency (i.e., Condition I and II events). Fuel performance evaluations were performed for each fuel region to indicate that the fuel rod design criteria will be satisfied for all fuel in the core and all fuel rod design criteria will be met at the increased steam generator tube plugging level. This will be confirmed for all fuel regions as part of the cycle specific reload safety evaluation process.

6.3.10 Balance of Plant Systems

The Byron and Braidwood Balance of Plant (BOP) fluid systems and components have been evaluated to assess the effects of increasing the SGTP level up to 15% and reducing the TDF to 89,700 gpm per loop. The evaluation compared the bounding NSSS performance parameters with the current bounding T_{Hot} Reduction Program parameters, to determine the impact on the following BOP systems:

- Main Steam System
- Condensate and Feedwater System
- Auxiliary Feedwater System
- Steam Generator Blowdown & Sampling System

The proposed performance parameters that affect the BOP systems and components, compared to the T_{Hot} reduction parameters, either do not change, or change in a favorable direction with increased SGTP levels of up to 15 percent. Additional information regarding BOP systems is provided in Section 8.0.

References

6.3-1. Byron/Braidwood, Updated Final Safety Analysis Report.

6.3-2. PCWG-1983, "Approval of Byron, Braidwood, & D. C. Cook PCWG Parameters," L. J. Paller, K. A. Fisher, and S. R. Spiegelman, September 7, 1993.

6.3-3. FD&RT-CSA-1095, "Evaluation of Design Transients for Byron/Braidwood SGTP/TDF Reduction Program," S. M. DiTommaso and L. E. Engelhardt, July 13, 1993.

6.3-4. MED-AEE-9738, "Byron 1&2 and Braidwood 1&2 Auxiliary Equipment Review for SG Tube Plugging and Reduced Thermal Design Flow," M. J. Zegar, J. E. Conklin, T. J. Legenzoff, T. J. Laubham, and L. I. Walker, November 15, 1993.

6.3-5. MED-PCE-13345, "Byron and Braidwood 15% SGTP/TDF Reduction," S. L Abbott, R. E. Tome, and D. E. Boyle, November 23, 1993.

6.3-6. LME-93-209, "RCP Motor Evaluation for 24 % Steam Generator Tube Plugging at Byron/Braidwood," P. C. Gaberson and B. R. Cox, December 1, 1993.

6.3-7. EA-93-257, "CAE/CBE/CCE/CDE Pressurizers Evaluation for 15 % Steam Generator Tube Plugging and Reduced Thermal Design Flow Program," J. K. Visaria, C. A. Lackhart, and W. B. Middlebrooks, December 1, 1993.

6.3-8. Byron Units 1 & 2 (CAE/CBE), Braidwood Units 1 & 2 (CCE/CDE) CRDM Model 93A - 15% SGTP/TDF Reduction Evaluation," R. J. Oleyar and L. E. Parsons, November 30, 1993.

6.3-9. FS-RCP-219, "Byron/Braidwood Units 1&2 RCP Evaluation for 15% SGTP/TDF Reduction Evaluation," R. W. Dunn and M. Bonfiglio, December 2, 1993.

6.3-10. FS-RCP-220, "Byron/Braidwood Units 1&2 Main Loop Stop Valves Evaluation for 15% SGTP/TDF Reduction Evaluation," R. W. Dunn and M. Bonfiglio, December 2, 1993.

6.3-11. NSD-JLH-3419, "Byron & Braidwood 15% Tube Plugging - S/G Thermal-Hydraulic Evaluation," G. P. Lilly, M. H. Hu, and J. L. Houtman, November 15, 1993.

6.3-12. WCAP-11388, "Byron Units 1&2 and Braidwood Units 1&2 T_{Hot} Reduction Program Engineering Report," May 1987.

6.3-13. NSD-JLH-3452, "Structural Evaluation of Byron/Braidwood Steam Generators for 15% Tube Plugging with Reduced Thermal Design Flow," G. S. Chakrabarti and J. L. Houtman, December 6, 1993.

6.4 Non-LOCA Evaluation

This section summarizes the non-LOCA reanalyses and evaluations performed to support the increase in the analysis values for the Steam Generator Tube Plugging in Byron Units 1 and 2 and Braidwood Units 1 and 2 from 10% to 24%. The analyses/evaluations also included the following assumptions:

a. +7 pcm/°F Moderator Temperature Coefficient
b. ±5% Main Steam Safety Valve Tolerance
c. ±4°F Rod Control Deadband
d. 25 second Diesel Generator Start Time
e. Revised Safety Injection Flows
f. 5% Loop Flow Asymmetry in one RCS Loop
g. A Vessel Average Temperature window of 569.1°F to 588.4°F

In addition to the above assumptions, the 1979 ANS decay heat model will be used in the analysis where appropriate.

The non-LOCA analyses were performed using the same codes and methods as described in the Byron & Braidwood UFSAR. The events analyzed and/or evaluated are listed in Table 6.4-1. Each of the events presented in Table 6.4-1 is classified by the American Nuclear Society (ANS) according to expected frequency of occurrence and severity of the accident. Each classification has specific acceptance criteria as discussed in each of the following sections. Additional information is presented in the introduction of UFSAR Section 15. None of the program assumptions described in this report affect the classification of transients discussed in this section.

Startup of an Inactive Reactor Coolant Loop

UFSAR Section 15.4.4 addresses operation of the Byron & Braidwood units with one RCP out of service. This event is caused by starting an idle RCP without bringing the inactive loop hot leg temperature close to the core inlet temperature. Since the Byron & Braidwood units are not licensed to operate with an RCP out of service, this analysis was not performed for the Steam Generator Tube Plugging Evaluation.

The references to N-1 loop operation have been deleted from the Byron & Braidwood Unit 1 and Unit 2 Technical Specifications. In addition, the existing UFSAR section is replaced by the following. "The Technical Specifications require that all four reactor coolant pumps be operating for reactor power operation and, therefore, operation with an inactive loop is precluded. This event was originally included in the FSAR licensing basis when operation with a loop out of service was considered.

Based on the current Technical Specifications which prohibit at-power operation with an inactive loop and the changes to the Technical Specifications which deleted all references to three-loop operation, this event has been deleted from the FSAR."

EOL MTC Surveillance Exemption

Most accident analyses use a constant moderator density coefficient (MDC) designed to bound the MDC at the worst set of initial conditions as well as at the most limiting set of transient conditions. This value of MDC forms the licensing basis for the current EOL MTC Technical Specification requirements. The conditional exemption from the measurement will be determined on a cycle-specific basis considering the amount of margin predicted to the Surveillance Requirement (SR) MTC limit and the performance of the other core parameters such as beginning of cycle MTC measurements and the critical boron concentration as a function of cycle life. Finally, the safety analysis assumption of a constant MDC for events analyzed at EOL, and the actual value assumed should not change. Therefore, the deletion of the EOL MTC surveillance measurement requirement, based on the margin to the SR limit, will not have an adverse impact on the non-LOCA safety analyses.

Modified Overtemperature and Overpower ΔT Setpoints

The implementation of the Revised Thermal Design Procedure; the inclusion of more conservative uncertainty values for RCS temperature and pressure; and changes in the steam generator tube plugging level, and RCS flow cause the core thermal protection limits to change. With the change in core thermal limits, the overpower and overtemperature ΔT reactor trip setpoints assumed in the safety analyses are changed. Safety analyses and evaluations performed to support this effort have verified that the core thermal limits are protected by the revised setpoints.

Table 6.4-1

List of Transients Evaluated or Analyzed for the Byron/Braidwood 24% SGTP Evaluation

Report Section	Transient	UFSAR Section(s)
Section 6.4.1	Excessive Load Increase Incident	15.1.3
Section 6.4.2	Excessive Heat Removal Due to Feedwater System Malfunctions	15.1.1 & 15.1.2
Section 6.4.3	Loss of External Electrical Load and/or Turbine Trip	15.2.1 through 15.2.5
Section 6.4.4	Loss of Offsite Power to the Station Auxiliaries (Station Blackout)	15.2.6
Section 6.4.5	Loss of Normal Feedwater	15.2.7
Section 6.4.6	Feedwater System Pipe Break	15.2.8
Section 6.4.7	Partial Loss of Forced Reactor Coolant Flow	15.3.1
Section 6.4.8	Complete Loss of Forced Reactor Coolant Flow	15.3.2
Section 6.4.9	Reactor Coolant Pump Shaft Seizure (Locked Rotor)	15.3.3 through 15.3.5
Section 6.4.10	Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal from a Subcritical Conditions	15.4.1
Section 6.4.11	Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power	15.4.2
Section 6.4.12	Uncontrolled Boron Dilution	15.4.6 & 15.5.2
Section 6.4.13	Rupture of a Control Rod Drive Mechanism	15.4.8
Section 6.4.14	Spurious Operation of Safety Injection System at Power	15.5.1
Section 6.4.15	Accidental Depressurization of the Reactor Coolant System	15.6.1
Section 6.4.16	Steam Line Break Evaluations	---

6.4.1 Excessive Load Increase Incident (UFSAR 15.1.3)

An excessive load increase incident is defined as a Condition II event resulting from a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the Reactor Protection System.

The excessive load increase event was analyzed to show that (1) the integrity of the core is maintained without actuation of the RPS as the DNBR remains above the safety analysis limit value, (2) the peak Reactor Coolant System and secondary system pressures remain below 110% of the design limit, and (3) the pressurizer does not fill. Of these, the primary concern was DNB and assuring that the DNBR limit is met.

Four cases were analyzed to demonstrate the plant behavior following a 10% step load increase from rated load. These cases are as follows:

1. Rod control in manual with Beginning of Life (BOL) minimum moderator reactivity feedback.

2. Rod control in manual with End of Life (EOL) maximum moderator reactivity feedback.

3. Rod control in automatic with BOL minimum moderator reactivity feedback.

4. Rod control in automatic with EOL maximum moderator reactivity feedback.

The effect of the increased steam generator tube plugging is included in the analyses performed for this event in that the reduced RCS flow rate is assumed. This combined with assuming that the average temperature is at the high end of the T_{avg} window minimizes the calculated DNBR. A 0 pcm/°F MTC is modeled for the BOL cases since a positive moderator temperature coefficient would yield less restrictive analysis results. The increased MSSV tolerance was not explicitly modeled for this event since secondary pressures decrease and the MSSV setpoints are never challenged. A uniform steam generator tube plugging level of 24% is assumed in the analyses.

Normal reactor control systems and Engineered Safeguard Features (ESFs) were not required to function for this event. However, the automatic rod control (including the ±4°F deadband) was modeled in two of the four cases analyzed to ensure that the worst case was presented. The RPS was assumed to be operable; however, reactor trip was not encountered in the analysis. No single active failure will prevent the RPS from performing its intended function.

The analyses demonstrate that, in the event of an excessive load increase, the DNBR will remain above the safety analysis limit DNBR value, thereby precluding fuel or clad damage and that peak reactor coolant and main steam pressures will not challenge the pressure limits.

6.4.2 Excessive Heat Removal Due to Feedwater System Malfunctions (UFSAR 15.1.1 and 15.1.2)

Two cases are analyzed and described for this ANS Condition II event in the UFSAR. A full power case is used to determine the plant response to a large step increase in the feedwater flow to one steam generator; a case is also analyzed for a large step increase in feedwater flow to one steam generator at zero power. This event was analyzed to show that (1) the integrity of the core is maintained by the RPS as the DNBR remains above the safety analysis limit value, (2) the peak Reactor Coolant System and secondary system pressures remain below 110% of the design limit, and (3) the pressurizer does not fill. Of these, the primary concern was DNB and assuring that the DNBR limit is met.

Multiloop (4/4) feedwater malfunction scenarios were also analyzed and found not to be limiting for this event.

For the full power case, the minimum DNBR is shown to remain above the safety analysis limit value. The zero power case indicates that the reactivity transient, and hence the minimum DNBR, is bounded by the rod withdrawal from subcritical event. The reduction in RCS flow has been shown to only slightly impact the minimum DNBR. Since the feedwater malfunction event is a cooldown event, increased steam generator tube plugging will benefit this event, due to the decreased primary to secondary side heat transfer caused by tube plugging. The reduced primary to secondary heat transfer will reduce the cooldown, which lowers the reactivity feedback due to the negative MTC assumed. Therefore, this event is analyzed assuming no steam generator tube plugging in order to maximize the cooldown, and subsequently, the positive reactivity feedback.

The reactivity insertion of the zero power feedwater malfunction event would decrease slightly as the TDF decreases and the SGTP increases because the primary to secondary heat transfer capability will be slightly decreased. This results in less of a primary cooldown and a less severe reactivity transient. The maximum reactivity insertion will remain bounded by the rod withdrawal from subcritical event.

Also, the feedwater temperature reduction transient remains bounded by the excessive load increase event, since the limiting conditions for this event have not changed.

Asymmetric steam generator tube plugging levels will result in flow and inlet temperature asymmetries between the RCS loops. The flow asymmetries, however, have no significant impact on the results of the feedwater malfunction analyses for Hot Full Power or Hot Zero Power.

The reactivity insertion rate of the feedwater malfunction event, driven by the RCS cooldown, will decrease if the thermal design flow decreases and the steam generator tube plugging increases because the primary to secondary heat transfer capacity will decrease. However, as previously discussed, the change in heat transfer capability is small and these effects are minimal. The reactivity insertion rate calculated for the zero power case is bounded by the RCCA withdrawal from subcritical analysis. Therefore, the conclusions in the UFSAR pertaining to the excessi feedwater flow event remain valid.

6.4.3 Loss of External Electrical Load and/or Turbine Trip (UFSAR 15.2.1 through 15.2.5)

The loss of external electrical load and/or turbine trip event is defined as a complete loss of steam load from full power without a direct reactor trip. This ANS Condition II event is analyzed as a turbine trip from full power, since it results in a more rapid reduction in steam flow, and thus bounds the loss of external electrical load event.

For a turbine trip, the reactor would be tripped directly (unless below 30% power) from a signal derived from the turbine autostop oil pressure and turbine stop valves. The automatic Steam Dump System accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the Steam Dump System and Pressurizer Pressure Control System are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation, an adequate level of decay and residual heat removal capability would be maintained by the Auxiliary Feedwater (AFW) System.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. The plant would be expected to trip from the RPS. A continued steam load of approximately 5% would exist after total loss of external electrical load because of the steam demand of plant auxiliaries, however, this is conservatively not modelled in the analysis.

Following a large loss of load the main steam safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, the OTΔT signal, the OPΔT signal, or the low-low steam generator water level signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves and main steam safety valves are sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the Steam Dump System. The steam dump valves will not be opened for load reductions of 10% or less but may open for larger load reductions. The RCS and Main

Steam System (MSS) steam relieving capacities were designed to ensure safety of the unit without requiring the automatic rod control, pressurizer pressure control, steam bypass control systems, or reactor trip on turbine trip.

The loss of load accident is analyzed (1) to confirm that the pressurizer and main steam safety valves are adequately sized to prevent overpressurization of the RCS and steam generators, respectively; (2) to form the basis of the required ASME overpressure protection report; and (3) to ensure that the increase in RCS temperature does not result in DNB in the core. The RPS is designed to automatically terminate any such transient before the DNBR falls below the limit value.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip. This assumption delays reactor trip until conditions in the RCS result in a trip on some other signal. Thus, the analysis assumes a worst case transient and demonstrates the adequacy of the pressure relieving devices and core protection margins.

The methodology utilized in the analyses of the Loss of Load/Turbine Trip event for the increased steam generator tube plugging is described in the Byron & Braidwood UFSAR. Cases are analyzed assuming both minimum (including the +7 pcm/°F MTC) and maximum reactivity feedback conditions with and without automatic pressurizer pressure control. For the cases analyzed to demonstrate that the core protection margins are maintained (BOL and EOL conditions with automatic pressurizer pressure control), uncertainties on initial conditions are not consistent with RTDP methodology (WCAP-11397-P-A). For the cases analyzed to demonstrate the adequacy of the pressure relieving devices (BOL and EOL conditions without automatic pressurizer pressure control), initial core power, reactor coolant temperature, and reactor coolant pressure are assumed at their maximum values consistent with steady-state full power operation including allowances for calibration and instrument errors.

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

The analyses performed assumed 24% uniform steam generator tube plugging, a primary coolant flow rate consistent with the increased steam generator tube plugging and primary temperature at the high end of the T_{avg} window to minimize the calculated DNBR. The increased secondary MSSV tolerances were explicitly modeled in all of the cases analyzed.

The results of the analyses show that the plant design is such that a total loss of external electrical load/turbine trip without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the MSS. Pressure-relieving devices incorporated in the plant's design are adequate to limit the maximum pressures to within the design limits. The integrity of the core is maintained; i.e., the DNBR is maintained above the safety analysis limit value. Thus, no core safety limit will be violated.

6.4.4 Loss of Offsite Power to the Station Auxiliaries (Station Blackout) (UFSAR 15.2.6)

(See Section 6.4.5)

6.4.5 Loss of Normal Feedwater (UFSAR 15.2.7)

The Loss of Offsite Power to the Station Auxiliaries is analyzed as a Loss of Normal Feedwater (LONF) with a loss of offsite power following reactor trip; consequently this event section will encompass both analyses.

Both Station Blackout and LONF are considered to be Condition II events which at worst will result in a reactor shutdown with the plant capable of returning to operation.

An increase in steam generator tube plugging, and resulting decrease in thermal design flow, decreases the primary to secondary heat transfer, consequently increasing the heatup of the primary system. Because Station Blackout and LONF are heatup events, they were analyzed assuming a uniform 24% steam generator tube plugging, which increases the heatup and consequently more conservatively models the events. This assumption conservatively bounds the asymmetric plugging scenario. In conjunction with the increased steam generator tube plugging, a +7 pcm/°F moderator temperature coefficient was assumed to maximize the sensible heat added to the coolant prior to the reactor trip. The increased MSSV tolerance was explicitly modeled in the analyses and the primary coolant was assumed to be at the low end of the T_{avg} window, which was shown to be conservative in previous Byron & Braidwood analyses.

With the incorporation of the increased steam generator tube plugging, the more positive moderator temperature coefficient and the increased MSSV tolerances, the results of the Station Blackout and LONF event analyses demonstrate that the pressurizer does not fill. All safety criteria continue to be met for these events.

6.4.6 Feedwater System Pipe Break (UFSAR 15.2.8)

For this ANS Condition IV event, the double-ended rupture of a main feedwater pipe initially results in a cooldown of the RCS due to the increased heat removal caused by the steam generator blowdown. This cooldown period is followed by a heatup as decay heat and stored energy, along with the lack of inventory in the steam generators result in inadequate heat transfer. The event is analyzed to show that adequate auxiliary feedwater flow exists to remove core decay heat and stored energy following a reactor trip from full power and that the core remains in a coolable geometry, and covered with water. Credit is taken for operator action to isolate the faulted steam generator within 30 minutes of reactor trip. Steam generator tube plugging potentially impacts the main feedwater line break event by reducing the RCS thermal design flow, and therefore, the primary to secondary heat transfer capability assumed in the analysis.

For ease of interpreting the transient, the more restrictive criterion of no bulk boiling in the primary coolant system following a feedwater pipe break prior to the time that the heat removal capacity of the steam generators, being fed auxiliary feedwater, exceeds NSSS heat generation, has been applied. This is verified by determining that the RCS coolant remains subcooled until the secondary side begins removing more heat than the primary side generates.

The lower RCS flow, combined with the increased tube plugging, will cause a greater heatup than the current UFSAR analysis. Also, the asymmetric tube plugging scenario may impact the analysis because the main feedwater line could break in the line feeding the steam generator with the highest number of plugged tubes (thus the lowest fraction of RCS flow). This will cause a different blowdown at the early stages of the event, which will affect the time at which the primary to secondary heat transfer degrades to the point where the NSSS is producing more power than the steam generators can remove. This will determine the minimum primary temperatures at the end of the cooldown phase of the event, and will affect the maximum RCS temperatures during the heatup portion of the event. However, even at the higher coolant temperatures in this scenario, the RCS coolant remains subcooled prior to the time of secondary side heat removal capability once again exceeds the primary side heat generation, and the core remains covered with water.

6.4.7 Partial Loss of Forced Reactor Coolant Flow (UFSAR 15.3.1)

A partial loss of coolant accident, an ANS Condition II event, can result from a mechanical or electrical failure in an RCP, or from a fault in the power supply to the RCPs. If the reactor is at power at the time of the accident, the immediate effect of the loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not promptly tripped.

Protection against a partial loss of coolant flow accident is provided by the low primary coolant flow reactor trip signal which is actuated in any reactor coolant loop by two out of three low flow signals. Above Permissive 8, low flow in any loop will actuate a reactor trip. For power levels between Permissive 7 (approximately 10% power) and Permissive 8 (30% power), a low flow in any two loops will actuate a reactor trip. A low flow in any loop will not initiate a reactor trip below Permissive 7.

The loss of two reactor coolant pumps with four loops in operation event is analyzed to show that (1) the integrity of the core is maintained as the DNBR remains above the safety analysis limit value, and (2) the peak RCS and secondary system pressures remain below the design limits. Of these, the primary concern is DNB and assuring that the DNBR limit is met.

The analysis is performed to bound operation with steam generator tube plugging levels up to a maximum uniform steam generator tube plugging level of $\leq$ 24% (including the corresponding reduction in RCS flow rate) and asymmetric steam generator tube plugging conditions such that up to a 5% asymmetric RCS loop flow exists. The +7 pcm/°F MTC is modeled and the primary coolant temperature is assumed to be at the high end of the T_{avg} window. The increased MSSV tolerance is not explicitly modeled since the DNBR results are not impacted by the secondary safety valve setpoints.

The results of the analysis have demonstrated that for the partial loss of coolant event, the DNBR does not decrease below the limit value at any time during the transient and the peak RCS and secondary system pressures remain below the design limits. Thus, no fuel or clad damage is predicted and all applicable acceptance criteria are met.

6.4.8 Complete Loss of Forced Reactor Coolant Flow (UFSAR 15.3.2)

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. This transient is classified as an ANS Condition III event. If the reactor is at power at the time of the accident, the immediate effect of the loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly.

The reactor trip on reactor coolant pump undervoltage is provided to protect against a loss of voltage to all reactor coolant pumps, i.e, station blackout. This function is blocked below approximately 10% power (Permissive 7). To protect against an underfrequency condition, resulting from frequency disturbances on the power grid, reactor trip on reactor coolant pump underfrequency is provided to trip the reactor.

The complete loss of flow transient is analyzed for a loss of all four reactor coolant pumps with four loops in operation. Although this is defined as a Condition III event, the event is conservatively analyzed to Condition II criteria. The event is analyzed to show that (1) the integrity of the core is maintained as the DNBR remains above the safety analysis limit value, and (2) the peak RCS and secondary system pressures remain below the design limits. Of these, the primary concern is DNB and assuring that the DNBR limit is met.

Two cases are analyzed to demonstrate that the undervoltage and underfrequency reactor trip functions provide adequate protection.

The analysis is performed to bound operation with steam generator tube plugging levels up to a maximum uniform steam generator tube plugging level of $\leq$ 24% (including the corresponding reduction in RCS flow rate). The +7 pcm/°F MTC is modeled and the primary coolant temperature is assumed to be at the high end of the T_{avg} window. The increased MSSV tolerance is not explicitly modeled since the DNBR results are not impacted by the secondary safety valve setpoints.

The analysis performed has demonstrated that for the complete loss of flow event, the DNBR does not decrease below the limit value at any time during the transient and the peak RCS and secondary system pressures remain below the design limit. Thus, no fuel or clad damage is predicted and all applicable acceptance criteria are met.

6.4.9 Reactor Coolant Pump Shaft Seizure (Locked Rotor) (UFSAR 15.3.3 through 15.3.5)

The postulated locked rotor accident, which is an ANS Condition IV event, is an instantaneous seizure of a reactor coolant pump rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low flow signal. The consequences of a postulated pump shaft break accident are similar to the locked rotor event. With a broken shaft, the impeller is free to spin, which results in a less severe coastdown. Therefore, the initial rate of reduction in core flow is greater during a locked rotor event than in a pump shaft break event because the fixed shaft causes greater resistance than a free spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient continues, the flow direction through the affected loop is reversed. If the impeller is free to spin, the flow to the core will be less than that available with a fixed shaft during periods of reverse flow in the affected loop.

The locked rotor analysis models the effect of a locked rotor in the faulted loop during forward flow conditions, and models a shaft break during reverse flow conditions. Consequently, the results for the locked rotor transients bound both a reactor coolant pump shaft seizure, as well as a shaft break.

At the beginning of the postulated RCP Locked Rotor accident, the plant is assumed to be in operation under the most adverse steady state operating conditions, i.e., a maximum steady state thermal power, maximum steady state pressure, and maximum steady state coolant average temperature.

The analysis is performed to bound operation with steam generator tube plugging levels up to a maximum uniform steam generator tube plugging level of $\leq$ 24% (including the corresponding reduction in RCS flow rate) and asymmetric steam generator tube plugging conditions such that up to a 5% asymmetric RCS loop flow exists. The +7 pcm/°F MTC is modeled and the primary coolant temperature is assumed to be at the high end of the T_{avg} window. The increased MSSV tolerance is not explicitly modeled since the results are not significantly affected by the secondary safety valve setpoints.

For the peak RCS pressure evaluation, the uncertainty on the initial pressure is conservatively estimated as 43 psi above the nominal pressure (2250 psia + 43 psi) to obtain the highest possible coolant pressure during the transient. The resulting peak primary system pressure is 2720 psia which occurs 3.6 seconds into the transient. This pressure is below the primary pressure limit of 2748.5 psia.

Two analyses are performed. The first conservatively assumes that the rods go into DNB as a conservative initial condition to determine the maximum clad temperature at the "hot spot" in the core and the peak primary pressure. The rod power at the hot spot is assumed to be 2.6 times the average rod power (i.e., F_Q= 2.6) at the initial core power level. Results from the "hot spot" analysis demonstrate that the applicable fuel clad limits are not exceeded. This is demonstrated by showing that the peak clad temperature is less than 2700°F and the maximum zirc-water reaction is less than 16% at the hot spot.

The second analysis is performed to determine the percentage of rods which experience DNB during the transient. Initial reactor power, pressurizer pressure, and RCS temperature are assumed to be at their nominal values consistent with RTDP methods. The results of this "rods-in-DNB" analysis demonstrate that zero percent of the rods are predicted to experience a DNBR less than the limit value.

In the event of a Locked Rotor or Shaft Break, all safety criteria are satisfied.

Reactor Coolant Pump Locked Rotor Radiological Evaluation

An evaluation was performed to determine the impact of 24% SGTP on the radiological consequences of the reactor coolant pump locked rotor accident. The evaluation was based on the assumptions and results of the analysis currently found in UFSAR Tables 15.0-11 and 12, and Table 15.3-3 and the steam releases to the environment from the steam generators which were specifically calculated for the 24% SGTP program. Also, no fuel failures are predicted for SGTP, consistent with the current UFSAR analysis.

In addition, the 0 to 8 hour doses at the Low Population Zone (LPZ) were extrapolated to 40 hours to account for a delay in the start of the RHR system. The current UFSAR analysis assumes that the RHR system starts at 8 hours, after which steam and activity release from the SG's to the atmosphere is assumed to cease. When single failure combined with elevated service water temperatures are considered, the RHR system may not have sufficient capacity at 8 hours to permit termination of the SG steam relief to the atmosphere.

The revised steam releases and the resulting doses are shown below:

Steam released to the atmosphere from 4 SG's (lbm)

0-8 hr	8-24 hr	24-40 hr
1.64×10^6	1.48×10^6	1.23×10^6

Estimated offsite doses (rem)

	Byron		Braidwood	
	thyroid	whole-body	thyroid	whole-body
2 hr site boundary	9.1×10^{-2}	4.4×10^{-4}	1.2×10^{-1}	6.0×10^{-4}
0-8 hr LPZ	1.8×10^{-2}	4.0×10^{-5}	7.4×10^{-2}	1.7×10^{-4}
0-40 hr LPZ	2.1×10^{-2}	5.7×10^{-5}	9.3×10^{-2}	2.7×10^{-4}

The estimated site boundary doses are unchanged from the current UFSAR. The estimated LPZ doses are greater than those of the current UFSAR analysis. However, the increases are small and the totals are a small fraction of the 10 CFR 100 guideline of 300 rem thyroid and 25 rem whole-body. Thus, there is no increase in consequences.

6.4.10 Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal From a Subcritical Condition (UFSAR 15.4.1)

A Condition II event, a RCCA withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCA banks resulting in a power excursion. This could occur with the reactor either subcritical, at HZP, or at power. The "at power" case is discussed in Section 6.4.11

The RCCA withdrawal from subcritical accident is terminated by the power-range high neutron flux reactor trip (low setting). The analysis assumed a 10% increase in the power range flux trip setpoint(low setting), raising it from the nominal value of 25% to a value of 35%.

The RCCA withdrawal from subcritical analysis employed the Standard Thermal Design Procedure (STDP) methodology. The RCS flow rate is based on the Thermal Design Flow and the initial RCS pressure is 43 psi below nominal. Since the event is analyzed from HZP, the steady-state STDP uncertainties on core power and RCS average temperature were not considered in defining the initial conditions.

The RCCA withdrawal from subcritical analysis also assumed a Doppler-only power defect consistent with the RSAC limit of 0.91%$\Delta\rho$, a MTC of +7 pcm/°F, a HZP nominal temperature of 557°F, a reactivity insertion rate of 70 pcm/sec, an initial power level of 1×10^{-9} of nominal power and 5% flow asymmetry (two reactor coolant pumps (RCPs) operating). Main Steam Safety Valves are not modeled for this event.

In conclusion, in the event of a RCCA withdrawal from the subcritical accident, the core and the RCS will not be adversely affected since the combination of thermal power and coolant temperature result in a DNBR greater than the limit value. Thus, no fuel or clad damage will result due to the RCCA withdrawal from subcritical transient.

6.4.11 Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power (UFSAR 15.4.2)

A Condition II event, the uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is defined as the inadvertent addition of reactivity to the core caused by the withdrawal of RCCA banks when the core is above the no-load condition. The reactivity insertion resulting from the bank (or banks) withdrawal will cause an increase in core nuclear power and subsequent increase in core heat flux. An RCCA bank withdrawal can occur with the reactor subcritical, at HZP, or at power. The uncontrolled RCCA bank at power event is analyzed for Mode 1 (power operation). The uncontrolled RCCA bank withdrawal from subcritical or low power condition is considered as an independent event in Section 6.4.10.

The uncontrolled RCCA bank withdrawal at power event was analyzed to show that (1) the integrity of the core is maintained by the RPS as the DNBR remains above the safety analysis limit value, (2) the peak RCS and secondary system pressures remain below the accident analysis pressure limits, and (3) the pressurizer does not reach a water solid condition and result in water relief through the pressurizer relief and safety valves.

Initial conditions for power, RCS pressure, and T_{avg} were at the nominal values. In performing the analysis, the following assumptions were made to assure bounding results were obtained for all possible normal operational conditions. Cases were analyzed assuming both minimum (including the +7 pcm/°F MTC at BOL) and maximum (EOL) reactivity feedback at 100%, 60% and 10% power.

The analyses assumed a uniform 24% steam generator tube plugging level and the corresponding primary coolant flow rate. The increased MSSV tolerance is modeled in the analysis and the primary coolant is assumed to be at the high end of the T_{avg} window.

In the event of an uncontrolled RCCA bank withdrawal at power, the high neutron flux, and OTΔT trip channels will provide adequate core protection over the entire range of possible reactivity insertion rates, i.e., the minimum calculated DNBR will always be greater than the safety analysis limit value. Pressurizer filling is prevented by these trips, or the high pressurizer level trip. In addition, peak pressures in the RCS and secondary steam system will not exceed 110% of their respective design pressures.

6.4.12 Uncontrolled Boron Dilution (UFSAR 15.4.6)

This Condition II event is analyzed for all six modes of plant operation. This analysis indicates that sufficient shutdown margin exists, such that should a dilution event occur, there is sufficient time following the alarm to allow operator termination or automatic mitigation of the event prior to a complete loss of shutdown margin. This event is analyzed for operating Modes 1 through 5. Mode 6 has administrative controls in place to preclude boron dilution during refueling.

Critical inputs for this event include active RCS volume (not including the pressurizer or pressurizer surge line), dilution flow rate, maximum critical boron concentration, and delta boron concentration between maximum critical concentration and the concentration at which the transient is initiated.

The boron dilution event for Byron/Braidwood was reanalyzed to indicate that margin exists, such that should a dilution event occur, there is sufficient time to allow operator action or automatic mitigation to terminate the event prior to a complete loss of shutdown margin. Although the reduced thermal design flow does not adversely affect the calculations, the increased SGTP reduces the RCS active volume assumed in the analyses. Results of the reanalysis for Modes 1 and 3 show that the operator has more than 15 minutes between alarm and loss of shutdown margin. The results of Modes 3, 4, and 5 show that the Boron Dilution Mitigation System has sufficient time to automatically terminate the dilution and begin reboration of the RCS before complete loss of shutdown margin. Therefore, the increased tube plugging levels will not impact the conclusions of the FSAR.

6.4.13 Spectrum of Rod Cluster Control Assembly Ejection Accidents (UFSAR 15.4.8)

This Condition IV accident is the result of the assumed mechanical failure of a control rod drive mechanism pressure housing such that the RCS pressure would eject the RCCA and drive shaft to the fully withdrawn position. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Four cases are analyzed.

1. Beginning of Cycle, Hot Full Power,
2. Beginning of Cycle, Hot Zero Power,
3. End of Cycle, Hot Full Power,
4. End of Cycle, Hot Zero Power,

These cases were analyzed with the lower thermal design flow which results from up to 24% steam generator tube plugging and the positive moderator temperature coefficient of a +7 pcm/°F. The secondary safety valves are not modeled in this analysis and the flow asymmetry is accounted for by reducing the RCS flow used in the hot spot transient calculation.

Using the methodology described in the Byron & Braidwood UFSAR, the analysis of the RCCA ejection accident showed all of the applicable acceptance criteria are met and therefore the conclusions as stated in the UFSAR remain valid.

6.4.14 Inadvertent Operation of Emergency Core Cooling System During Power Operation (UFSAR 15.5.1)

An inadvertent Emergency Core Cooling System (ECCS) actuation at power is an ANS Condition II event which is assumed to be initiated at full power. The injection of highly concentrated (2300 ppm) borated water into the RCS reduces core power, temperature and pressure until the reactor trips on low pressurizer pressure.

The RCS power and temperature reductions produce a similar reduction in pressure on the secondary side of the plant. Steam generator tube plugging potentially impacts this event by reducing the RCS thermal design flow. However, the reduction in flow and the changes in secondary side operating conditions due to SGTP would have no significant impact on the transient behavior. The analysis shows that the minimum DNBR is never less than the initial value, which is well above the safety analysis limit value.

Asymmetric steam generator tube plugging levels will create flow and inlet temperature asymmetries between the RCS loops. The UFSAR results show that the DNBR is never less than the initial value. Furthermore, the effects of asymmetric tube plugging will not impact the behavior of this event. Therefore, the conclusions presented in the UFSAR remain valid.

6.4.15 Accidental Depressurization of the Reactor Coolant System (UFSAR 15.6.1)

The most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety valve. Initially, this Condition II event results in a rapid decrease in RCS pressure which could reach the hot leg saturation pressure if a reactor trip did not occur. The pressure continues to decrease throughout the transient. The effect of the pressure decrease would be to decrease power via the moderator density feedback. The pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip. The reactor may be tripped by either of the following RPS signals: (1) OTΔT or (2) pressurizer low pressure.

Initial core power, reactor coolant average temperature, and RCS pressure were assumed to be at their nominal values consistent with steady-state full-power operation. Uncertainties in initial conditions were included in the DNBR limit. An MTC of +7 pcm/°F was assumed in this analysis. The analysis was performed assuming no steam generator tube plugging to enhance the primary to secondary heat transfer capability but the RCS flow rate assumed is consistent with the higher steam generator tube plugging. The increased MSSV tolerance has no impact on the results of an RCS Depressurization event.

The analyses demonstrate that the pressurizer low pressure and the OTΔT reactor protection trip functions will provide adequate protection against the accidental depressurization of the RCS. The minimum DNBR will remain in excess of the limit value; thus the acceptance criterion is met.

6.4.16 Steam Line Break Evaluations

The steamline break events, including core response, mass and energy releases both inside and outside containment, and steamline break at hot full power, have been evaluated. The evaluation considered 24% steam generator tube plugging, reduced thermal design flow, +7 pcm/°F MTC, RCS loop flow asymmetry, and increased MSSV tolerance. The results of this evaluation found that the zero power steamline break core response statepoint remains valid. An assessment of DNB shows that the DNB design basis will continue to be met for the spectrum of break sizes. This will be verified as part of the cycle specific reload evaluation.

Steam Line Break Radiological Evaluation

An evaluation was performed to determine the impact of 24% SGTP on the radiological consequences of the steam line break. The evaluation was based on the assumptions and results of the analysis currently found in UFSAR Tables 15.0-11 and 12, and Table 15.1-3 and the steam releases to the environment from the unaffected steam generators which were specifically calculated for the 24% SGTP program.

In addition, the 0 to 8 hour doses at the LPZ were extrapolated to 40 hours to account for a delay in the start of the RHR system. The current UFSAR analysis assumes that the RHR system starts at 8 hours, after which steam and activity release from the SG's to the atmosphere is assumed to cease. When single failure combined with elevated service water temperatures are considered, the RHR system may not have sufficient capacity at 8 hours to permit termination of the SG steam relief to the atmosphere.

The revised steam releases and the resulting doses are shown below:

Steam Released to the Atmosphere (lbm)

	0-8 hr	8-24 hr	24-40 hr
Unaffected SG's	1.34×10^6	1.23×10^6	9.8×10^5
Affected SG	1.7×10^6	2000	2000

Estimated offsite doses (rem)

	Byron		Braidwood	
	thyroid	whole-body	thyroid	whole-body
2 hr site boundary	28.9	0.4	39	0.6
0-8 hr LPZ	4.4	0.03	18.4	0.1
0-40 hr LPZ	5.6	0.04	25.1	0.2

The estimated site boundary doses are unchanged from the current UFSAR. The estimated LPZ doses are greater than those of the current UFSAR analysis. However, the increases are small and the totals are a small fraction of the 10 CFR 100 guideline of 300 rem thyroid and 25 rem whole-body. Thus, there is no increase in consequences.

6.4.17 Non-LOCA Conclusions

The non-LOCA accident transients have been reanalyzed or evaluated for the Byron/Braidwood increased steam generator tube plugging program. All events, whether reanalyzed or evaluated, meet the appropriate safety criteria. The safety evaluation also addressed the effects of EOL MTC surveillance elimination on the non-LOCA safety analyses.

It is therefore concluded that the Byron/Braidwood increased steam generator tube plugging level with reduced thermal design flow, positive moderator temperature coefficient, flow asymmetry, and main steam safety valve tolerance increase can be accommodated to the applicable FSAR safety limits.

6.5 Steam Generator Tube Rupture (SGTR) Evaluation

6.5.1 Introduction

The SGTR analysis is performed to evaluate the two major SGTR potential consequences of concern, specifically:

- Margin to Overfill (MTO) case - the potential for overfilling the faulted steam generator before the Auxiliary Feedwater (AFW) can be isolated and the break flow terminated.

- Offsite Dose (OD) case - the potential to release primary system activity through the secondary side in excess of 10CFR100 limits.

The SGTR transient has been analyzed for steam generator tube plugging levels up to 10% and has demonstrated acceptable results. In anticipation of tube plugging levels exceeding 10% and the reduction of RCS Thermal Design Flow, a reanalysis of the SGTR transient was performed. The revised analysis assesses the effect of an increase in tube plugging up to 24% with a reduced TDF of 89,700 gpm per loop from 94,400 gpm per loop. The revised analysis is documented in Reference 6.5-5. The following provides a summary of the conclusions.

6.5.2 Licensing Basis

Following the 1982 Ginna SGTR event, the NRC expressed concerns over traditional FSAR assumptions and methodology used for this transient. In particular, it was assumed that the operator terminated the break flow into the ruptured SG within 30 minutes. In response to the NRC's concerns, the Westinghouse Owners Group (WOG) addressed the SGTR licensing issues on a generic basis by issuing WCAP-10698 and Supplement 1 to WCAP-10698 (References 6.5-1 and 6.5-2, respectively). Subsequently, CECo submitted plant specific SGTR analysis for Byron and Braidwood (Reference 6.5-3) in accordance with the NRC SER requirements for the referenced WCAPs. The NRC approved the CECo methodology by issuing an SER for the Byron/Braidwood SGTR transient analysis (Reference 6.5-4).

The SGTR transient is analyzed using the thermal-hydraulic transient analysis computer code RETRAN02MOD3. The revised SGTR analysis incorporating increased tube plugging levels and a reduction in RCS TDF utilizes the same methodology and conservative assumptions approved by the NRC in Reference 6.5-4. Operator action is critical in mitigating the consequences of the SGTR event and, therefore, the analysis methodology includes the simulation of the operator actions required for recovery from a steam generator tube rupture event. The operator actions assumed for the MTO and OD cases are based on the plant-specific emergency operating procedures (EOPs), which were developed from the latest revision of the WOG Emergency Response Guidelines (ERGs). The revised SGTR analysis assumes the same operator action time intervals used in previous analyses (Reference 6.5-3).

6.5.3 Analysis

The revised SGTR analysis was performed using the same operator action times and single failure assumptions detailed in Reference 6.5-3. All other conservative initial condition and input assumptions discussed in Reference 6.5-3 were also applied with the exception of those changes required to incorporate the reduction in TDF and the differences in the RCS and secondary parameters associated with increased tube plugging.

The MTO case is considered terminated when the RCS pressure has equalized with the ruptured SG pressure, thereby terminating break flow. The purpose of performing this case is to ensure that the SG does not overfill and that liquid does not enter the SG exit nozzle affecting the main steam line and associated piping supports. The revised analysis results in 71.3 cubic feet of available margin to overfill, compared to 124.2 cubic feet calculated for the 10% tube plugging analysis (Reference 6.5-6). This represents a reduction of approximately 53 cubic feet in available margin to overfill. Therefore, the conclusion in Reference 6.5-6 that there is available margin to overfill for Byron and Braidwood Units 1 and 2 in the event of a steam generator tube rupture event has not changed.

For the Offsite Dose analysis, the primary to secondary break flow and the steam release to atmosphere from both the ruptured and intact steam generators was calculated for use in determining the activity released to atmosphere. The mass releases were calculated using the same RETRAN control system discussed, in detail , in Reference 6.5-3 from the initiation of the event until termination of break flow. Two Offsite Dose cases are analyzed for the SGTR transient, the Preaccident Iodine Spike and the Concurrent Iodine Spike cases. The difference between the two Offsite Dose cases is the initial RCS concentration of radionuclides. The releases calculated using the RETRAN control system are used to determine the radiation doses at the Exclusion Area Boundary (EAB) and the Low Population Zone for Byron and Braidwood Stations. The offsite doses, in REM, for the revised analysis are as follows:

Preaccident Iodine Spike Case:

	Byron EAB		Byron LPZ	
	Thyroid	Body	Thyroid	Body
24% TP	18.87	0.2028	0.5629	0.0060

	Braidwood EAB		Braidwood LPZ	
	Thyroid	Body	Thyroid	Body
24% TP	25.50	0.2740	2.3510	0.0253

Concurrent Iodine Spike Case:

	Byron EAB		Byron LPZ	
	Thyroid	Body	Thyroid	Body
24% TP	17.84	0.2015	0.5322	0.0060

	Braidwood EAB		Braidwood LPZ	
	Thyroid	Body	Thyroid	Body
24% TP	24.11	0.2722	2.2228	0.0251

10 CFR 100 Dose Limits

	EAB		LPZ	
	Thyroid	Body	Thyroid	Body
Limit	300.0	25.0	300.0	25.0
Accept.	30.0	2.5	30.0	2.5

As indicated in the above Tables, all of the doses remain within the SGTR dose guidelines in 10CFR100 and Standard Review Plan 15.6.3.

6.5.4 Conclusions

Based on the results of the SGTR analysis incorporating 24% tube plugging with reduced TDF, it is concluded that there is available margin to overfill and the offsite radiation doses are within the guidelines estab[illegible] in 10CFR100 and Standard Review Plan 15.6.3.

References

6.5-1 WCAP-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to SG Overfill", August 1987.

6.5-2 Supplement 1 to WCAP-10698-P-A, [illegible]ion of Offsite Radiation Doses for a Steam Generator Tube Rupture Accide[illegible], March 1986.

6.5-3 Commonwealth Edison Report, "Steam Generator Tube Rupture Analysis for Byron and Braidwood Plants, Revision 1", February 1990.

6.5-4 NRC Safety Evaluation Report for Byron Units 1 and 2 and Braidwood Units 1 and 2 Steam Generator Tube Rupture (SG[illegible]), Docket Nos. STN 50-454, 50-455, 50-456 and 50-457, dated April 23, 1992.

6.5-5 Commonwealth Edison Nuclear Fuel Services Calc note RSA-B-93-06, "Byron/Braidwood Steam Generator Tube Rupture Analysis with Increased Tube Plugging and Reduced RCS Flow", dated November, 1993.

6.5-6 Commonwealth Edison Nuclear Fuel Services Calcnote RSA-B-90-02, "Byron and Braidwood Steam Generator Tube Rupture Analysis with 10% SG Tube Plugging", dated April, 1990.

6.6 Loss-of-Coolant Accident (LOCA) Evaluation

Commonwealth Edison is proceeding with a program to allow operation at the Byron/Braidwood stations with up to 15% Steam Generator Tube Plugging in any steam generator, Thermal Design Flow reduced by 5% to 89,700 gpm/loop, 5% RCS loop flow asymmetry, ±5% tolerance on the steam generator Main Steam Safety Valves (MSSVs), and implementation of Positive Moderator Temperature Coefficient. The PMTC program results in an increase in the minimum and maximum Refueling Water Storage Tank (RWST) and accumulator boron concentrations, which directly affects some of the Loss-of-Coolant Accident (LOCA) and LOCA-related analyses. The revised minimum RWST boron concentration is 2300 ppm and the maximum is 2500 ppm. The revised minimum accumulator boron concentration is 2200 ppm while the maximum is 2400 ppm.

In this section of the report, the changes associated with the programs described above will be evaluated with respect to the LOCA and LOCA-related analyses. These analyses are as follows:

Large Break LOCA	FSAR Chapter 15.6.5
Small Break LOCA	FSAR Chapter 15.6.5
Hot Leg Switchover / Long Term Core Cooling	FSAR Chapters 6.3.2 & 15.6.5
Post-LOCA Long Term Core Subcriticality	FSAR Chapter 15.6.5
LOCA Hydraulic Forces	FSAR Chapter 3.6.2

In addition to the changes associated with the SGTP/TDF/PMTC Program described above, Commonwealth Edison has implemented the Revised Thermal Design Procedure. This has resulted in a change to some of the uncertainties which can potentially affect the LOCA analyses. (See Section 1.3)

The acceptance criteria for the Emergency Core Cooling System, identified in Part 50.46 of the Code of Federal Regulations, Title 10 are as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long lived radioactivity remaining in the core.

LOCA related analyses are performed in order to demonstrate that the criteria given above are met. The first three criteria are addressed by the large and small break LOCA analyses. The fourth criterion is addressed in the LOCA hydraulic forces analysis, and the small and large break LOCA analyses. The fifth criterion is addressed in the post-LOCA long term core subcriticality and hot leg switchover calculations.

6.6.1 Large Break Loss-of-Coolant Accident (UFSAR 15.6.5)

The Byron/Braidwood FSAR licensing basis large break LOCA (LBLOCA) analysis (Reference 6.6-1 analysis) was performed with the 1981 Large Break LOCA Evaluation Model with BASH (Reference 6.6-2). The analysis resulted in a Peak Cladding Temperature (PCT) of 1883°F for a double-ended cold leg guillotine break with a discharge coefficient of 0.6 and has since been supplemented by a number of safety evaluations. The penalties associated with these evaluations have increased the large break LOCA PCTs to 1980°F for Byron Unit 1, 1993°F for Byron Unit 2, 2047°F for Braidwood Unit 1, and 1993°F for Braidwood Unit 2. Therefore, the total PCT for each of the units remains below the 2200°F limit.

The effect of the SGTP/TDF Reduction program and the PMTC program on the Byron/Braidwood LBLOCA analysis is described below.

6.6.1.1 LBLOCA SGTP/TDF Reduction Evaluation

The current large break LOCA analysis for Byron/Braidwood modeled a steam generator tube plugging level of 15% and a thermal design flow reduced by 2%. Thus, there is no effect on the results with respect to the SGTP, and the net reduction in TDF that must be considered is 3%.

<u>TDF Reduction</u>:

Reductions in TDF can have two primary effects on the LOCA analysis. The first is the reduction in initial RCS flow itself and the second is the potential change in T_{avg} resulting from the TDF reduction. A change in the initial RCS flow assumed in the analysis will have a negligible effect on the results of the analysis. The RCS flow after initiation of the accident is almost immediately dominated by the break flow, such that small changes in initial flow do not significantly affect the large break LOCA transient. As such, a 3% reduction in initial RCS flow will not affect the results of the Byron/Braidwood large break LOCA analysis.

The 3% net reduction in TDF will result in a ~1°F reduction in the T_{avg} from what was assumed in the analysis. However, the sensitivity of PCT to initial RCS temperature for Byron/Braidwood (documented in Table 15.6-3 of Appendix C to Reference 6.6-1) is such that decreasing the T_{avg} would be expected to decrease the calculated PCT. Therefore, the ~1°F reduction in temperature will not increase the large break LOCA PCT for Byron/Braidwood.

RCS Loop Flow Asymmetry:

RCS loop flow asymmetry has been shown to have an insignificant effect on the results of large break LOCA analyses. This is because the break almost immediately dominates the flow through the loops, such that the PCT calculated later in the transient is negligibly affected by changes in initial flow. Thus, the 5% loop flow asymmetry will not affect the results of the large break LOCA analysis.

MSSV Tolerance Increase:

The steam generator MSSVs are not modeled in Westinghouse large break LOCA analyses. As such, changes in the tolerances of these valves will not affect the results of the Byron/Braidwood large break LOCA analysis.

RTDP Uncertainties:

The uncertainties associated with RTDP will not affect the large break LOCA analysis. The pressure control uncertainty of ±33.4 psi has been determined to have a negligible effect on the results of the large break LOCA analysis. This is because the calculated PCT is virtually unaffected by small changes in initial pressure, due to the rapid depressurization of the system. The temperature uncertainty associated with RTDP is approximately 1°F larger than that currently supported by the large break LOCA analysis. However, this potential increase in temperature is offset by the reduction in T_{avg} associated with the reduced TDF. Thus, there is no net effect on the results of the large break LOCA analysis. The power uncertainty is bounded by that assumed in the analysis. Since the analysis models thermal design flow, the uncertainty on RCS flow does not affect the results.

6.6.1.2 LBLOCA PMTC Evaluation

The 1981 Large Break LOCA Evaluation Model with BASH (Reference 6.6-2) which was used to perform the current licensing basis LBLOCA analysis (Reference 6.6-1) does not include the modeling of the boron content of injected water as a means to prevent excessive cladding temperatures. As such, the changes associated with the PMTC program will have no effect on the results of the large break LOCA analysis.

6.6.1.3 LBLOCA Conclusions

The SGTP/TDF Reduction and PMTC programs at Byron/Braidwood have been evaluated with respect to their effect on the licensing basis large break LOCA analysis. No change in PCT was assessed as a result of the changes associated with these programs. The results of the large break LOCA analysis continue to comply with the requirements of 10 CFR 50.46.

6.6.2 Small Break Loss-of-Coolant Accident (UFSAR 15.6.5)

The Byron/Braidwood FSAR licensing basis small break LOCA (SBLOCA) analysis (Reference 6.6-1) was performed with the Small Break LOCA NOTRUMP Evaluation Model (Reference 6.6-3). The analysis resulted in a PCT of 1453°F for a three inch diameter break in the cold leg and has since been supplemented by a number of safety evaluations. The penalties associated with these evaluations have increased the small break LOCA PCT above 1453°F. The total PCT, however, is still below the 2200°F limit.

The effect of the SGTP/TDF Reduction program and the PMTC program on the Byron/Braidwood SBLOCA analysis is described below.

6.6.2.1 SBLOCA SGTP/TDF Reduction Evaluation

The current small break LOCA analysis for Byron/Braidwood modeled a steam generator tube plugging level of 15% and a thermal design flow reduced by 2%. Thus, there is no effect on the results with respect to the SGTP and the net reduction in TDF that must be considered is 3%.

TDF Reduction:

Reductions in TDF can have two primary effects on the LOCA analysis. The first is the reduction in initial RCS flow itself and the second is the potential change in T_{avg} resulting from the TDF reduction. A change in the initial RCS flow assumed in the analysis will have a negligible effect on the results of the analysis. The RCS flow after initiation of the accident is almost immediately dominated by the break flow, such that small changes in initial flow do not significantly affect the small break LOCA transient. For example, the break flow rate associated with the 3 inch break transient is 1440 lbm/sec at ~1 second after the initiation of the accident. The break flow rate then drops to a value between 500 lbm/sec and 600 lbm/sec prior to steam venting. The effect of this break flow is such that the system flow rate reached 0 lbm/sec at ~400 seconds into the transient. Given the substantial break flow rate, rapid depressurization (~2280 psi to ~1300 psia in 100 seconds), and quick decrease in system flow rate, a 3% reduction in initial RCS flow will not affect the results of the Byron/Braidwood small break LOCA analysis.

The 3% net reduction in TDF will result in a ~1°F reduction in the T_{avg} from what was assumed in the analysis. However, the sensitivity of PCT to initial RCS temperature for Byron/Braidwood (documented in Table 15.6-3 of Appendix C to Reference 6.6-1) is such that decreasing the T_{avg} would be expected to decrease the calculated PCT. Therefore, the ~1°F reduction in temperature will not increase the small break LOCA PCT for Byron/Braidwood.

RCS Loop Flow Asymmetry:

RCS loop flow asymmetry has been shown to have an insignificant effect on the results of small break LOCA analysis. This is because the break almost immediately dominates the flow through the loops, such that the PCT calculated later in the transient is negligibly affected by changes in initial flow. Thus, the 5% loop flow asymmetry will not affect the results of the small break LOCA analysis.

MSSV Tolerance Increase:

The steam generator MSSVs are modeled in Westinghouse small break LOCA analyses. As such, changes in the tolerances of these valves will affect the results of the Byron/Braidwood small break LOCA analysis. Westinghouse pressurized water reactors are dependent upon heat transfer from the reactor coolant system primary to the steam generator secondary in order to limit the consequences of a small break LOCA. A period exists when the RCS primary pressure equilibrated above the steam generator secondary pressure, during which decay heat is transferred from the RCS fluid to the steam generators. Since a loss of offsite power is assumed to occur coincident with the small break LOCA, the steam dump system and power operated relief valves are assumed to be inactive. Thus, steam relief from the steam generator secondaries takes place through the MSSVs. The lowest set-pressure MSSV can provide sufficient steam relief to remove the existing decay heat, such that the steam generator pressure equilibrated slightly above the lowest MSSV set-pressure. Since the RCS pressure is limited by the steam generator pressure as dictated by the MSSV, an increase in the MSSV set-pressure will tend to reduce the safety injection provided by the centrifugal ECCS pumps as a result of the higher reactor coolant system pressures. A conservative evaluation of the potential effect of a +5% MSSV tolerance on the calculated PCT for the most limiting small break of Reference 6.6-1 was performed. It was found that the increase in the MSSV tolerance from the currently modeled value of +3% to the proposed value of +5% would result in a 100°F increase in the small break LOCA PCT.

A methodology has been developed to determine the PCT effect of the Small Break LOCA Burst and Blockage issue (Reference 6.6-4) for small break LOCA analyses which did not calculate burst at Beginning-of-Life fuel rod conditions. This methodology utilizes a computer code to calculate the PCT increase resulting from the postulated burst of fuel rods with accrued burnup. For BOL PCTs which are less than ~1700°F, there is no penalty. Thus, since the Byron/Braidwood SBLOCA PCT has always been less than 1700°F, no penalty was ever calculated. However, the addition of the 100°F penalty due to an increase in MSSV setpoint tolerance will increase the resultant PCT sufficiently such that the methodology predicted a 15°F increase in PCT due to the postulated fuel rod burst. Thus, the total increase in SBLOCA PCT is 115°F.

RTDP Uncertainties:

The uncertainties associated with RTDP will not affect the small break LOCA analysis. The pressure control uncertainty of ±33.4 psi has been determined to have a negligible effect on the results of the small break LOCA analysis. This is because the calculated PCT is virtually unaffected by small changes in initial pressure, due to the rapid depressurization of the system. It was found that the delay in depressurizing to the reactor trip setpoint is small enough such that the decay heat fraction at any given time during the transient is negligibly affected. The temperature uncertainty associated with RTDP is approximately 1°F larger than that currently supported by the large break LOCA analysis. However, this potential increase in temperature is offset by the reduction in T_{avg} associated with the reduced TDF. Thus, there is no net effect on the results of the small break LOCA analysis. The power uncertainty is bounded by that assumed in the analysis. Since the analysis models thermal design flow, the uncertainty on RCS flow does not affect the analysis.

6.6.2.2 SBLOCA PMTC Evaluation

The Small Break LOCA NOTRUMP Evaluation Model (Reference 6.6-3) which was used to perform the current licensing basis SBLOCA analysis (Reference 6.6-1) does not include the modeling of the boron content of injected water as a means to prevent excessive cladding temperatures. Core shutdown is modeled to occur when the control rods are inserted after the low pressurizer pressure reactor trip setpoint is reached (with appropriate delays and rod drop time). The negative reactivity associated with the boron in the RCS and ECCS water is not modeled. As such, the changes associated with the PMTC program will have no effect on the results of the small break LOCA analysis.

6.6.2.3 SBLOCA Conclusions

The SGTP/TDF Reduction and PMTC programs at Byron/Braidwood have been evaluated with respect to their effect on the licensing basis small break LOCA analysis. A 115°F increase in PCT was assessed as a result of the changes associated with these programs. However, the results of the small break LOCA analysis continue to comply with the requirements of 10 CFR 50.46.

6.6.3 Blowdown Reactor Vessel and Loop Forces (UFSAR 3.6.2)

The blowdown hydraulic forcing functions resulting from a postulated large break LOCA are considered in Chapter 3.6.2 of the Byron/Braidwood UFSAR. This section of the UFSAR addresses the effects of a pipe rupture on the reactor coolant system and serves as a basis for the core and reactor internals integrity analysis.

The peak loads generated on the reactor vessel as a result of a large break LOCA typically occur between 10 and 500 milliseconds and subside well before 1 second. Since the forces peak and subside within 1 second of the transient initiation, the only changes which typically affect this analysis are those involving system initial conditions, especially initial RCS temperature. In this section of the report, the changes associated with the SGTP/TDF Reduction program and the PMTC program will be evaluated with respect to the Byron/Braidwood LOCA forces analysis.

6.6.3.1 LOCA Forces SGTP/TDF Reduction Evaluation

As stated above, this analysis is sensitive to RCS initial conditions, specifically initial RCS cold leg temperature. The LOCA forces analyses are based upon T_{cold} conditions, since this tends to increase the magnitude of the LOCA hydraulic forces. It was found that the Tcold modeled in the Byron/Braidwood forces analysis is only slightly larger than that associated with the reduced TDF. As such, the results of the forces analysis are negligibly affected by the TDF reduction.

As with the large break LOCA analysis, the LOCA forces analysis is negligibly affected by changes in the initial RCS loop flow. This is because the loop flow is immediately dominated by the break flow. Thus, the 5% loop flow asymmetry and the reduction in RCS loop flow itself will not affect the results of the LOCA forces analysis.

Since the hydraulic forces peak and subside within 1 second of break initiation, the increase in steam generator MSSV tolerances will not affect the results of this analysis. This is because the automatically operated safety features cannot respond before this time and because the steam generator pressures cannot reach the set-pressures of the MSSVs this quickly.

The change in uncertainties associated with RTDP will not affect the results of this analysis. This is because the RTDP uncertainties are either bounded by those considered in the current analysis or have a negligible effect on the results of the forces analysis.

6.6.3.2 LOCA Forces PMTC Evaluation

The LOCA forces analyses do not include the modeling of the boron content of injected water. Also, as stated above, the peak LOCA forces typically occur between 10 and 500 milliseconds and subside within 1 second. As such, the changes associated with the PMTC program will have no effect on the results of the LOCA forces analysis.

6.6.4 Post-LOCA Long Term Cooling - Core Subcriticality (UFSAR 15.6.5)

The Westinghouse licensing position for satisfying the requirements of 10 CFR 50.46 Section (b) Item (5), "Long-Term Cooling", is defined in WCAP-8339 (Reference 6.6-5). The Westinghouse commitment is that the reactor will be maintained in a shutdown state by ECCS borated water. Since credit is not taken for the control rods in large break LOCA analyses, the ECCS water provided by the RWST and accumulators must contain enough boron, when combined with other borated and non-borated sources of water, to maintain the core subcritical in the post-LOCA long term.

For each cycle of operation, the ability of the ECCS system to maintain the core subcritical following a LOCA is reevaluated. The calculation of expected post-LOCA sump boron concentration is checked to determine if any of the pertinent parameters, such as water volumes and boron concentrations, have changed since the last cycle. The object of the calculation is to conservatively determine the anticipated sump boron concentration by minimizing or maximizing RCS component boron concentrations and water volumes appropriately. The calculated sump boron conditions are then compared to the subcriticality requirements of the new core design.

The PMTC program resulted in an increase in the RWST and accumulator minimum and maximum boron concentrations. The minimum RWST boron concentration is 2300 ppm and the maximum is 2500 ppm. The minimum accumulator boron concentration is 2200 ppm while the maximum is 2400 ppm. As discussed below, these changes necessitated a recalculation of the post-LOCA containment sump boron concentration.

6.6.4.1 Post-LOCA Long Term Core Subcriticality SGTP/TDF Reduction Evaluation

The calculation of the post-LOCA sump boron concentration does not include modeling of SGTP, RCS Flow, or the MSSVs directly. However, a change in the RCS temperature could potentially change the initial RCS mass, which is modeled in the calculation. As noted previously, the reduction in TDF will affect the RCS average temperature by ~1°F. A change of this magnitude will have a small effect on the initial RCS mass, which in turn will have an insignificant effect on the results of the calculation. This is because the calculation is dominated by the RWST water mass and boron concentration, such that small changes in RCS mass or boron concentration tend to have a minor effect on the results. As such, the changes associated with the SGTP/TDF Reduction program will have a negligible effect on the results of the post-LOCA long term core subcriticality calculation.

The same argument made above also applies to the change in temperature uncertainty associated with RTDP.

6.6.4.2 Post-LOCA Core Subcriticality PMTC Evaluation

Post-LOCA boron concentration curves were generated at varying RWST and accumulator boron concentrations and it was demonstrated that for an RWST boron concentration as low as 2300 ppm, there is a sufficient average RCS/sump mixed boron concentration to ensure that the post-LOCA core remains subcritical in consideration of the PMTC program. Since the increase in RWST boron concentration to 2300 ppm is sufficient to keep the core subcritical following a LOCA, the heat generation in the core will not increase beyond that produced from normal post-shutdown decay heat. As such, post-LOCA core cooling is not in question with respect to increases in core heat generation due to recriticality.

6.6.5 Hot Leg Switchover to Prevent Boron Precipitation/Long Term SI Verification (UFSAR 15.6.5 and 6.3.2)

Hot leg recirculation switchover time is determined for inclusion in the emergency operating procedures and is calculated to ensure that no boron precipitation occurs in the core as a result of post-LOCA boiling. The time at which hot leg switchover occurs is dependent on core power history and RCS component water volumes and boron concentrations.

The input for this calculation is similar to that of the Post-LOCA Long Term Core Cooling calculation, except that the boron concentrations are maximized for conservatism.

A Westinghouse requirement for the hot leg switchover calculation is that the boiloff rate in the core must be matched by safety injection flow at the time of hot leg switchover, for both large and small break LOCA, such that boron buildup in the core is stopped and vessel water inventory is maintained (i.e., the core is covered).

The PMTC program resulted in an increase in the RWST and accumulator minimum and maximum boron concentrations. The minimum RWST boron concentration is 2300 ppm and the maximum is 2500 ppm. The minimum accumulator boron concentration is 2200 ppm while the maximum is 2400 ppm. As discussed below, these changes necessitated a recalculation of the hot leg switchover time.

6.6.5.1 Hot Leg Switchover SGTP/TDF Reduction Evaluation

As with the Post-LOCA Long Term Core Subcriticality calculation, the calculation of the hot leg switchover time does not include explicit modeling of SGTP, RCS Flow, or the MSSVs. However, as with the Post-LOCA Long Term Core Subcriticality calculation, a change in the RCS temperature could potentially change the initial RCS mass, which is modeled in the calculation. A change of this magnitude will have a small effect on the initial RCS mass, which in turn will have an insignificant effect on the results of the calculation. This is because the calculation is dominated by the RWST water mass and boron concentration, such that small changes in RCS mass or boron concentration tend to have a minor effect on the results. As such, the changes associated with the SGTP/TDF/PMTC Analysis Program will have a negligible effect on the results of the hot leg switchover calculation.

The same argument made above also applies to the change in temperature uncertainty associated with RTDP.

6.6.5.2 Hot Leg Switchover PMTC Evaluation

A hot leg switchover time of 8.5 hours was calculated assuming a maximum RWST boron concentration of 2500 ppm and a maximum Accumulator boron concentration of 2400 ppm. At these boron concentrations, and at the calculated hot leg switchover time of 8.5 hours the following minimum flow requirements, previously transmitted in Reference 6.6-6, must be met in order to match the calculated core boil-off rates.

40 lbm/sec for Hot Leg Injection (with no lines spilling) at an RCS pressure of 14.7 psia.
46 lbm/sec for Cold Leg Injection (with no lines spilling) at an RCS pressure of 14.7 psia.
22 lbm/sec for all SI against RCS pressures of 1000 psia to 1250 psia.

6.6.6 LOCA Conclusions

The effect on the Byron/Braidwood LOCA related accident analyses of the SGTP/TDF Reduction and PMTC programs has been evaluated. The results of the evaluation show that the small and large break LOCA PCTs will not increase above the regulatory limit of 2200°F. The small break LOCA analysis PCT, however, was calculated to increase by 115°F as a result of increasing MSSV tolerance to ±5%. The LOCA Hydraulic Forces, Post-LOCA Long Term Core Subcriticality, and Hot Leg Switchover analyses results are unaffected by the changes associated with these programs. Thus, the acceptance criteria are met in that:

1. the small and large break LOCA PCTs do not exceed the 2200°F limit.

2. the maximum percent of cladding reacted in the large break analysis, substantially lower than 17%, will not increase beyond the 17% limit.

3. the total hydrogen generated will not exceed 0.01 times the hypothetical amount that would be generated were all the cladding to react, as generically demonstrated for Westinghouse large and small break LOCA analyses.

4. the LOCA Hydraulic Forces analysis results are unaffected, thus the core geometry will remain amenable to cooling.

5. the Post-LOCA Long Term Core Subcriticality and hot leg switchover calculations are unaffected, thus the core will remain subcritical and decay heat will continue to be removed following a LOCA.

Westinghouse also evaluated the effects on the Byron/Braidwood LOCA and LOCA related analyses of RTDP uncertainties. It was found that the uncertainties associated with RTDP are accommodated by those either directly modeled in or currently evaluated for the Byron/Braidwood LOCA analyses. Thus, there is no effect on the results of the LOCA and LOCA-related analyses.

References

6.6-1. 89CB*-G-0083, "Commonwealth Edison Project, Byron/Braidwood Nuclear Power Plant, VANTAGE 5 Reload Transition Safety Report", Swogger, J. W., July 18, 1989.

6.6-2. WCAP-10266-P-A, Rev.2 (Proprietary), "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code", Besspiata, J. J., et. al., March, 1987.

6.6-3. WCAP-10054, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code", N. Lee, et al., August, 1985.

6.6-4. CAE-91-189/CCE-91-204, "Commonwealth Edison Company, Byron/Braidwood Stations, ECCS Evaluation Model Changes", Humphries, B. S., June 20, 1991.

6.6-5. WCAP-8339, "Westinghouse Emergency Core Cooling System Evaluation Model - Summary", Bordelon, F. M., et al., June 1974.

6.6-6. CAE-93-240/CCE-93-262, "Commonwealth Edison Company, Byron/Braidwood Stations, Hot Leg Switchover Time and Minimum Flow Requirements", Humphries, B. S., November 23, 1993.

6.6-7. CECo Letter NFS:RSA:93-154, "HLSO Time and Minimum Flow Results", Kovar, K. N., December 10, 1993.

6.7 Containment Response

An evaluation was performed to determine the impact of increased steam generator tube plugging (24%), Thermal Design Flow reduction, increased RWST boron concentration, implementation of PMTC, and revised RTDP uncertainties, on the current licensing basis LOCA mass and energy releases, the subcompartment analyses, and the containment integrity analyses for Byron/Braidwood.

The data in Section 2.1 reflect steam generator tube plugging (SGTP) increased from 15% to 24%, with the maximum T_{Hot} limited to 618.4°F and the minimum Tcold limited to 538.2°F. The range of RCS temperatures evaluated for this program are a Vessel outlet range of 601.6°F to 618.4°F and a vessel/core inlet range of 538.2°F to 558.4°F. Since increased SGTP is conservative, because of the decreased RCS mass and the decreased secondary to primary heat transfer, and since the RCS temperature ranges are bounded by those used in the Byron/Braidwood T_{Hot} Reduction Program and the Economic Generation Control Programs, the SGTP and temperature evaluation results are still bounding.

Also evaluated were reductions in thermal design flow, increased RWST boron concentrations, PMTC, and revised RTDP uncertainties. There is no significant impact of the reduction in Thermal Design Flow from 94,400 gpm/loop to 89,700 gpm/loop on the current LOCA short and long term releases. This variable has essentially no effect on the short term instantaneous releases, and in the long term, no impact on the total energy content of the RCS. There is no impact of increased RWST Boron concentrations and PMTC on the LOCA releases. These changes do not adversely affect the normal plant operating parameters, system actuations, accident mitigating capabilities or assumptions important to the short term and long term LOCA mass and energy releases, and the subcompartment and containment responses to these events, or create conditions more limiting than those assumed in these analyses. The evaluation of the RTDP uncertainties, including an RCS temperature uncertainty of 8.74°F and a pressure uncertainty of 33.4 psi, have shown that the current limiting analyses remain bounding. The small change in Pressure/Temperature uncertainties is offset by analysis conservatism.

Since the mass and energy releases due to a postulated main steamline break (MSLB) do not change, the current MSLB containment analysis remains bounding.

Summary and Conclusions:

An evaluation to determine the impact of the TDF reduction, Steam Generator Tube Plugging (up to 24%), increased RWST Boron Concentrations, PMTC, and revised RTDP uncertainties on the current licensing basis LOCA mass and energy releases, the subcompartment analyses, and the containment integrity analyses for Byron/Braidwood has been completed. The evaluation has demonstrated that the current analyses and evaluations performed for the

Byron/Braidwood Economic Generation Control Program remain bounding. The current MSLB containment response analysis also remains bounding.

6.8 Radiological and Hydrogen Evaluations

6.8.1 Background

The Technical Specifications for Byron and Braidwood currently specify a minimum RWST boron concentration of 2000 ppm (Section 3.1.2.6) and a range of 1900 ppm to 2100 ppm for the SIS accumulators (Section 3.5.1). The RWST boron concentration is increased to a range of 2300 ppm to 2500 ppm. The accumulator boron concentration is increased to a range of 2200 ppm to 2400 ppm.

The increase in RWST and SIS accumulator boron concentration reduces the containment spray pH and the minimum equilibrium sump solution pH following a postulated large break Loss-of-Coolant Accident (LOCA). The proposed change is reviewed relative to the impact of the sump and spray pH on:

1. Iodine removal from the containment atmosphere by sprays and retention in the sump solution.

2. The production and control of hydrogen gas produced in the containment due to the corrosion of aluminum and zinc.

6.8.2 Licensing Basis

Iodine Removal and Retention:

Limiting the release of radioactive iodine is necessary to minimize the thyroid doses resulting from an accident. Based on 10CFR100.11, the plant design, in combination with the selected plant site, should have calculated accident doses that are less than 300 rem to the thyroid.

Hydrogen Production Post-LOCA:

Production of hydrogen inside the containment after a LOCA must be limited and controlled to assure that flammable levels of hydrogen are not attained. According to the Byron/Braidwood UFSAR Section 6.2.5, the concentration of H_2 will not reach 4.0% by volume. This limit is consistent with the recommendation of Regulatory Guide 1.7 (Reference 6.8-1).

6.8.3 Evaluation

Sump pH / Elemental Iodine Decontamination Factor (DF):

Section 6.5.2.2 of the UFSAR currently specifies a minimum sump solution pH of 8.5. The UFSAR states that this is needed to attain an iodine partition coefficient greater than 3.5 x 10^3 which is needed to support an elemental iodine DF of 100. Reference 6.8-2 indicates that the minimum calculated sump solution pH for the proposed RWST boron increase is 8.5, which is consistent with the current radiological design basis. However, to add additional margin, an evaluation was performed to determine if a pH less than 8.5 would still support the DF 100 assumption. Thus, a value of 8.0 was assumed.

The partition coefficient cited in the UFSAR is assumed to have been based on the data of Eggleton (Reference 6.8-3), since Eggleton is referenced in UFSAR Appendix A6.5. For this evaluation, the equilibrium Eggleton data along with the more conservative time dependent data found in Reference 6.8-4 were utilized.

The results of the evaluation show that the minimum sump solution pH case presented in Reference 6.8-2 and the iodine partition data for pH 8.0 from either Reference 6.8-3 or 6.8-4 will support the required DF 100.

Iodine Removal by Containment Spray:

The iodine removal effectiveness of the containment sprays is described in UFSAR Appendix A6.5. The spray removal coefficient (λ_s) for elemental iodine is 29.9 hr^{-1} and it is based on a spray pH of 9.8 (UFSAR Table A6.5-1), which is also specified as the maximum pH. The minimum spray pH does not appear to be specified in the UFSAR nor is it contained in the Technical Specifications. However, both NRC and ANS (References 6.8-5 and 6.8-6) recommend a minimum pH of 8.5

For this evaluation, the spray pH range was assumed to be 8.5 to 9.8.

The minimum spray pH calculated for the RWST boron increase is 9.2 (Reference 6.8-2). Since this pH is within the range stated above, one might expect to have no adverse impact on the iodine removal coefficient. However, this is not the case.

The iodine removal model referenced in Appendix A6.5 (Reference 6.8-7) shows a strong dependence on pH, which suggests that the λ_s calculated at pH 9.8 may not be supported at pH 9.2. The iodine partition coefficient, which is a function of pH, determines the λ_s, rather than the actual pH value. Thus, the partition coefficient (H) needed to support the λ_s must first be determined followed by the corresponding pH.

Note: The Byron/Braidwood SER (Ref. 11) utilized a λ_s of 10 hr^{-1}. It was the NRC's preference to utilize the smaller of either the calculated λ_s or 10 hr^{-1} (Reference 6.8-5, 6.8-8). Based on current methodology (Reference 6.8-12), a λ_s less than 20 hr^{-1} would be insensitive to spray pH.

The general form of λ_s is written as follows:

$$\lambda_s = \frac{EFH}{V}$$

where: λ_s = iodine removal coefficient
E = 0.6 (absorption efficiency estimated for a mass mean drop diam. of 1000 μ from Reference 6.8-8)
F = 3285 gpm (minimum spray flow rate) (note 1)
H = 5000 (iodine partition coefficient) (note 2)
V = 2.76×10^6 ft^3 (containment volume)

Notes:

1. The spray flow rate of 3285 gpm is the flow from the weaker of the two spray pumps. The UFSAR assumed 3795 gpm, which is the flow from the stronger pump (UFSAR Section 6.5.2.1).

2. Reference 6.8-8 suggests a partition of 5000 based on the results of the CSE Experiments (Reference 6.8-13). Although Reference 6.8-8 makes no mention of pH, CSE utilized a spray pH of approximately 9.

The resulting λ_s is 29 hr^{-1}, which is sufficiently close to the analysis value of 29.9. To determine the solution pH that will support this λ_s, the partition data presented in the Standard Review Plan (Reference 6.8-5) is used. Although Byron and Braidwood are not SRP plants, the SRP data is utilized in lieu of any plant specific data. The SRP provides a conservative interpretation of pH vs. H for use in spray effectiveness calculations. Inspection of SRP Figure 6.5.2-1 shows that a maximum partition of 5000 is achieved with a pH $\geq$ 8.5. The minimum pH calculated for the RWST boron increase is 9.2.

Thus, both the UFSAR and SER LOCA dose analyses are still valid.

Post-LOCA Hydrogen Production:

The analysis presented in Section 6.2.5.3 of the Byron/Braidwood UFSAR assumes that hydrogen is produced in the containment post-LOCA due to the corrosion of aluminum and zinc, radiolytic decomposition of the core cooling solution, and the reaction of the zirconium fuel cladding with steam. However, only the corrosion of aluminum and zinc are affected by the pH of the spray and sump solution.

The hydrogen production analysis described in the UFSAR does not specify solution pH. It was assumed that the corrosion rates were based on a pH of approximately 11.0. To evaluate the effect of pH on aluminum and zinc corrosion, the data presented in Reference 6.8-9 was be used, which presents zinc and aluminum corrosion as a function of pH. Inspection of Reference 6.8-9 shows maximum (and similar) zinc corrosion rates at pH 7 and 11. Hence, any pH within this range would result in zinc corrosion rates that are equal to or less than those used in the UFSAR analysis. Aluminum corrosion rates are shown to decrease with decreasing pH. Hence, aluminum corrosion rates at pH less than 11 will be less than the rates used in the UFSAR analysis. Thus, the UFSAR hydrogen production analysis remains valid for the RWST boron increase.

Reference 6.8-2 provides a cautionary statement with regard to exceeding the maximum spray pH of 11 during spray recirculation addition of caustic. Corrosion rates for pH > 11 may exceed the analysis values. Additionally, the effects of the increased boron concentration on zinc corrosion were estimated based on the guidance of Reference 6.8-10. Only zinc corrosion is addressed since similar data is not available for aluminum corrosion. The results of the estimate indicate that for high temperature conditions (270°F assumed) the zinc corrosion rate for a 2500 ppm boron solution increases by approximately 7% over that expected for a 2000 ppm solution. At low temperature conditions (150°F assumed) the rate decreases by approximately 3 percent.

Although there is a calculated increase in corrosion rate at high temperature conditions, the overall increase in hydrogen generation is small and can be considered insignificant. The hydrogen contribution from each source is presented in UFSAR Figure 6.2-35. Inspection of Figure 6.2-36 shows that hydrogen recombiner is started at approximately 24 hours post-LOCA. The hydrogen concentration at this time is approximately 2%. Branch Technical Position CSB 6-2, 11/24/75, and Standard Review Plan, Section 6.2.5 suggests only 0.5 % margin to the flammable limit before taking mitigating action, i.e., start recombiner when H_2 concentration reaches 3.5%. The impact of the increased zinc corrosion rate is evaluated at the recombiner start time. At 24 hours, approximately 50% of the total hydrogen is produced by the corrosion of zinc and zinc based paint (UFSAR Figure 6.2-35). If the high temperature condition is assumed to persist for the first 24 hours of the accident, the total hydrogen accumulation could potentially increase in direct proportion to the corrosion rate increase or by a maximum of 3.5% (i.e., 0.5 * 0.07). The additional hydrogen will increase the total concentration at 24 hours, from 2 to approximately 2.1 vol/%, which is still well within the 3.5% limit for starting the recombiner. However, the peak temperature persists for a short time (UFSAR Figure 6.2-12), and drops rapidly. Thus, the corrosion rates will quickly approach those assumed in the UFSAR analysis (for 2000 ppm boron) and then drop below these rates for the duration of the accident recovery.

Thus, a small but insignificant increase in hydrogen produced post-LOCA is predicted. There is no adverse impact on the time to start or on the operation of the hydrogen recombiner.

6.8.4 Conclusion

Based on the evaluation presented, the proposed RWST/accumulator boron increase will have no adverse impact on either LOCA radiological consequences or post-LOCA hydrogen production and control.

References

6.8-1 "Control of Combustible gas Concentrations in Containment Following a Loss-of-Coolant Accident," USNRC Regulatory Guide 1.7.

6.8-2 Westinghouse Fluid Systems Design and Analysis ıetter, "Impact of PMTC of +7 pcm/ F and an Increase in RWST Boron Concentration on the Byron/Braidwood NSSS Auxiliary Fluid Systems," FSE/FSDA-2359, November 19, 1993.

6.8-3 A. E. J. Eggleton, "A Theoretical Examination of Iodine-Water Partition Coefficients," AERE-R-4887, UKAEA, Atomic Energy Research Establishment, Harwell, Berks, England, 1967.

6.8-4 "Predicted Rates of Formation of Iodine Hydrolysis Species at pH Levels, Concentrations, and Temperatures Anticipated in LWR Accidents," Oak Ridge National Laboratory, NUREG/CR-2900, October 1982.

6.8-5 "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", NUREG-75/087, Section 6.5.2, November, 1975.

6.8-6 "American National Standard for PWR and BWR Containment Spray System Design Criteria", ANS/ANSI-56.5-1979.

6.8-7 "Iodine Removal By Spray in the Joseph M. Farley Station Containment," Westinghouse, WCAP-8376, July 1974.

6.8-8 Postma, A.K., Pasedag, W.F., "A Review of Mathematical Models for Predicting Spray Removal of Fission Products in Reactor Containment Vessels", Battelle Pacific Northwest Labs., WASH-1329, June, 1974.

6.8-9 "Corrosion Study for Determining Hydrogen Generation From Aluminum and Zinc During Post-Accident Conditions", Westinghouse, WCAP-8776, April, 1976.

6.8-10 NUREG/CR-2812, The Relative Importance of Temperature, pH and Boric Acid Concentration of Rates of H_2 Production from Galvanized Steel Corrosion," Sandia National Laboratories, November 1983.

6.8-11 "Safety Evaluation Report by the Office of Nuclear Reactor Regulation, USNRC, in the Matter of Commonwealth Edison Company Byron Station Units 1 and 2, and Braidwood Station Units 1 and 2," USNRC NUREG-75/023, April 4, 1975, Section 6.2.3.

6.8-12 "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", NUREG-0800, Section 6.5.2, Rev. 2, July, 1988.

6.8-13 Coleman, L.F., "Iodine Gas-Liquid Partition", Nuclear Safety Quarterly Report, February, March, April, 1970, BNWL-1315-2, Battelle-Northwest, 1970.

6.9 Assessment of Unreviewed Safety Question

The evaluation of the NSSS, BOP Systems, and safety-related components has shown that 15% SGTP, reduction in TDF from 94,400 gpm to 89,700 gpm per loop, 5% RCS loop flow asymmetry, incorporation of a PMTC of +7 pcm/°F, increase in RWST and accumulator boron concentration and an increased MSSV tolerance of ±5 (SGTP/TDF/PMTC Program analysis assumptions) have adverse effect on the integrity, availability, or function of the Byron and Braidwood NSSS. Based on the information presented in the evaluation, it can be concluded that the SGTP/TDF/PMTC Program assumptions do not represent a potential unreviewed safety question, as defined in 10CFR50.59, in that it:

1. Will not increase the probability of an accident previously evaluated in the FSAR.

   No. The evaluations and analyses performed for the proposed SGTP/TDF/PMTC Program demonstrated that operability and integrity of the evaluated Nuclear Steam Supply or Balance of Plant Systems and components will not be affected. The SGTP/TDF/PMTC Program assumptions do not result in a condition where the design, material, and construction standards that were applicable prior to the effort are aitered. In addition, the safety functions of the evaluated systems and components have not been altered. Therefore, the probability of an accident previously analyzed in the FSAR is not increased by the SGTP/TDF/PMTC Program.

2. Will not increase the consequences of an accident previously evaluated in the FSAR.

   No. The proposed SGTP/TDF/PMTC Program assumptions do not change, degrade, or prevent the response of the evaluated safety-related systems and components such that their function in the control of radiological consequences is affected. In addition, the program assumptions do not change, degrade or prevent the response of the evaluated safety related systems and components to accident scenarios, as described in the FSAR. Safety design requirements and all applicable safety analysis criteria continue to be met and the radiological consequences of accidents previously evaluated in the FSAR are not adversely affected. Therefore, the consequences of an accident previously evaluated in the FSAR will not be increased.

3. Will not create the possibility of an accident that is different than any previously evaluated in the FSAR.

   No. All aspects of the SGTP/TDF/PMTC Program have been evaluated, and no new or different accidents or failure modes have been identified for any system or component important to safety. Nor has any new credible limiting single failure been created. Because the SGTP/TDF/PMTC Program does not adversely affect the integrity of the steam generator or any other equipment, it is determined that an accident different than any evaluated in the FSAR will not be created.

4. Will not increase the probability of a malfunction of equipment important to safety previously evaluated in the FSAR.

   No. The SGTP/TDF/PMTC Program has not identified any new failure modes for the evaluated safety-related systems and components. The SGTP/TDF/PMTC analysis assumptions do not result in any original design specification, such as seismic requirements, electrical separation requirements, and environmental qualification, being altered. In addition, the SGTP/TDF/PMTC Program does not result in equipment used in accident mitigation to be exposed to an adverse environment. Therefore, the probability of a malfunction of equipment important to safety previously evaluated in the FSAR will not be increased.

5. Will not increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR.

   No. The performance and integrity of the evaluated safety-related systems and components are not affected such that their control of radiological consequences is altered. The SGTP/TDF/PMTC Program does not result in a different response of safety-related systems and components to accident scenarios than that postulated in the FSAR. No new equipment malfunctions have been introduced that will affect fission product barrier integrity. Therefore, the SGTP/TDF/PMTC Program will not increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR.

6. Will not create the possibility of a malfunction of equipment important to safety different than previously evaluated in the FSAR.

   No. The SGTP/TDF/PMTC Program assumptions do not have any affect on the ability of the evaluated safety-related systems and components to perform their intended safety functions. The analysis assumptions associated with the SGTP/TDF/PMTC Program do not create failure modes that could adversely impact safety-related equipment. Therefore, it will not create the possibility of a malfunction of equipment important to safety different than previously evaluated in the FSAR.

7. Will not reduce the margin of safety as described in the bases to any technical specification.

No. The evaluation of the licensing basis accident analyses demonstrated that the applicable analysis acceptance criteria will continue to be met with the revised analysis assumptions associated with the SGTP/TDF/PMTC Program. Since all applicable safety analysis acceptance criteria were met there is no reduction in the margin of safety as defined in the bases to any technical specification.

6.10 Conclusion

Based upon the information provided herein, it can be concluded that an increase in the level of steam generator tube plugging to a maximum of 15% in any one steam generator, with a maximum flow asymmetry of 5%, implementation of a +7 pcm/°F PMTC, increased MSSV setpoint tolerance of ±5%, increased minimum RWST boron concentration of 2300 ppm, and an increased minimum safety injection accumulator boron concentration of 2200 ppm does not constitute an unreviewed safety question, provided the new overall minimum thermal design flow (TDF) limit of 358,800 gpm is maintained.

7.0 NUCLEAR FUEL EVALUATION

An evaluation of the effects of the increased steam generator tube plugging level (24%), reduced Thermal Design Flow limit (89,700 gpm per loop), and positive moderator temperature coefficient (+7 pcm/°F) on the fuel design was performed with respect to the core design, the thermal-hydraulic design and fuel rod performance.

7.1 Core Design

The licensing basis for the increased steam generator tube plugging and decreased TDF limit includes the licensing of a Positive Moderator Temperature Coefficient Technical Specification. The effect of PMTC on Core Design is an increase in the soluble boron concentrations required for various normal and transient core operating conditions. For the maximum PMTC allowed, Core Design estimated the soluble boron requirements under the current Byron/Braidwood fuel management. These higher boron concentrations are part of the safety analysis licensing basis for both LOCA and non-LOCA. Boron duty requirements were also considered and evaluated.

7.2 Thermal-Hydraulic Design

Thermal-hydraulic analyses were performed to support the reduction in Minimum Measured Flow from 390,390 gpm to 366,000 gpm. The analyses are based on the Revised Thermal Design Procedure described in Reference 7.0-1, the WRB-2 DNB correlation in Reference 7.0-2, and the improved THINC-IV PWR design modeling method described in Reference 7.0-3. The thermal-hydraulic design criteria and methods remain the same as those presented in the Byron/Braidwood Station UFSAR with the exceptions noted below. All of the current UFSAR thermal-hydraulic design criteria are satisfied. The flow values used in the T/H analyses conservatively bound the technical specification flow values.

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes and DNB correlation predictions were considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values were determined such that there is at least a 95 percent probability at a 95 percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and operational transients and during transient conditions arising from faults of moderate frequency (i.e., Condition I and II events). Since the parameter uncertainties were considered in determining the RTDP design limit DNBR values, the plant safety analyses were performed using input parameters at their nominal values. For this application, the design limit DNBR value is 1.25 for typical and thimble cells.

The primary DNB correlation used in the analysis of the VANTAGE 5 fuel is the WRB-2 DNB correlation. The W-3 DNB correlation, References 7.0-4 and 7.0-5, is used where the primary correlation is not applicable.

The improved THINC-IV PWR design modeling method is used for the DNBR analyses of the VANTAGE 5 fuel. This modeling scheme improves the accuracy of the analyses by minimizing the inaccuracies which result from the use of the perturbation technique in the solution of the governing equations.

7.3 Fuel Rod Performance

Fuel performance evaluations were performed for each fuel region to indicate that the fuel rod design criteria will be satisfied for all fuel in the core under the specified operating conditions. Evaluations of the effect of the proposed design parameters on meeting the fuel rod design criteria were performed for the Byron and Braidwood units. Based on the evaluations, all fuel rod design criteria will be met at the increased steam generator tube plugging level. This will be confirmed for all fuel regions as part of the cycle specific reload safety evaluation process.

References

7.0-1 Friedland, A. J., Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, April 1989.

7.0-2 Davidson, S. L. (Editor), "Reference Core Report - VANTAGE 5 Fuel Assembly," WCAP-10444-P-A, September 1985.

7.0-3 Friedland, A. J., Ray, S., "Improved THINC IV Modeling for PWR Core Design," WCAP-12330-A, September 1991.

7.0-4 Tong, L. S., "Critical Heat Fluxes in Rod Bundles, Two Phase Flow and Heat Transfer in Rod Bundles," Annual Winter Meeting ASME, November 1968.

7.0-5 Tong, L. S., AEC Critical Review Series, "Boiling Crisis and Critical Heat Flux,", TID-25887, 1972.

8.0 NSSS/BALANCE OF PLANT INTERFACE EVALUATION

The Byron & Braidwood Units 1 and 2 Balance of Plant (BOP) fluid systems and components have been evaluated to assess the effects of increasing the SGTP level to 24%, which corresponds to a reduction in the TDF limit from 94,400 gpm per loop to 89,700 gpm per loop. The evaluation compared the bounding NSSS performance parameters shown in Table 2.1-1 with the current bounding T_{Hot} Reduction Program parameters identified in Table 2.1-1 of WCAP-11388 (Reference 8.0-1) to determine the impact on the following BOP systems:

- Main Steam System
- Condensate and Feedwater System
- Auxiliary Feedwater System
- Steam Generator Blowdown & Sampling System

The proposed performance parameters which affect the BOP systems and components, compared to the T_{Hot} reduction parameters, either do not change, or change in a favorable direction with increased SGTP levels of up to 24%. For example, the core power level of 3411 MWt remains the same. The 24% SGTP final feedwater temperature of 440°F remains unchanged as well as no load T_{avg} and secondary steam pressure. Also, the revised parameters show a trend toward decreasing full power steam mass flowrates. Consequently, the full power feedwater mass flow rates also decrease. One significant change in parameters which can have a negative impact on BOP system performance is the change in the full power steam pressure, where the lower bounding 24% SGTP full power steam pressure (740 psia) is below the lower bounding T_{Hot} reduction full power steam pressure (827 psia). However, since turbine-generator volumetric flow design considerations limit the minimum steam generator pressure to 827 psia, the parameters identified for the T_{Hot} Reduction Program are considered to remain bounding with respect to the 24% SGTP reduced TDF Program BOP systems evaluation. Consequently, the results of the BOP systems evaluation for the T_{Hot} Reduction Program contained in WCAP-11388 remain valid for increased SGTP level up to 24% coupled with reduced TDF. The results of this evaluation expand on the T_{Hot} Reduction Program evaluation and also address the effects of current program options (i.e., ±5% MSSV setting tolerance) on the BOP systems performance.

8.1 Main Steam System

The increase in the SGTP level up to 24% will have no adverse effects on the design of the Main Steam System or its components. The system design pressure will remain at 1200 psia. The full power steam mass and volumetric flow rates will remain within the bounding parameters of the T_{Hot} Reduction Program. The effects of the increased steam generator tube plugging on system components is discussed below.

8.1.1 Steam Generator Safety Valves

Since the system design pressure does not change, there is no need to revise the setpoints of the Main Steam Safety Valves. The rated relief capacity of these valves will also be adequate for operation at the increased tube plugging level, since the NSSS power has not changed.

8.1.2 Steam Generator Power Operated Relief Valve (PORVs)

The steam generator power operated relief valves provide the first step of overpressure protection for the steam generators and the means for plant cooldown by steam discharge to the atmosphere if the condenser steam dump is not available (such as upon loss of electrical power to station auxiliaries). The adjustable setpoint of the PORV's is set between zero load steam pressure and the setpoint of the lowest set steam generator safety valve. Since neither of these pressures change in the increased tube plugging condition there is no need to change the PORV setpoint. Sizing of the PORV's is based on controlling plant cooldown when the steam dump is not available. During these situations the PORV's are required to reduce the steam pressure from the Main Steam System design pressure to a condition (350°F RCS hot leg temperature) where the Residual Heat Removal System can be placed into operation. The required cooldown rate is 50°F/hr throughout the entire cooldown to ensure that the normally aligned condensate water supply is not depleted. The limiting condition for valve sizing is the 50°F/hr cooldown rate at 100 psia steam pressure. A steam pressure of 100 psia is required to achieve the 350°F hot leg temperature when cooling down on natural circulation of the reactor coolant during a loss of off-site power. Since this design condition and the plant power rating is within the bounds of the T_{Hot} Reduction Program parameters, the present capacity of the PORV's will be adequate for operation at the increased tube plugging level.

8.1.3 Main Steam Isolation Valves (MSIVs)

Rapid closure of the MSIVs is required to mitigate the effects of a steam line or feed line break. One condition causing isolation of these valves is low steam line pressure. The current low steam line pressure setpoint is 640 psig. The pressure span between the original design full power steam pressure and the low pressure setpoint is 350 psi (990 psia - 640 psia). In the increased tube plugging condition the pressure span between full power steam pressure and the low pressure setpoint may be as low as 187 psi (827 psia - 640 psia). It is not expected that this decrease in the pressure span will be a problem. A review of the Main Steam System normal operating transients has confirmed that down pressure transients in excess of 150 psi are not likely to occur.

Rapid closure of the MSIVs causes a significant differential pressure across the valve seats and a thrust load on the Main Steam System piping and piping supports in the area of the MSIVs. The worst case for design occurs with zero load pressure at the beginning of the transient, since this results in the highest steam pressure and the maximum stored energy in the steam generators. Since the zero load pressure has not changed in going from the current design to a SGTP level of 24%, the design loads and associated stresses resulting from rapid closure of the MSIVs will not change due to the increased tube plugging level.

8.1.4 Steam Dump (Turbine By-pass) Valves

The Byron/Braidwood Steam Dump System is designed to permit 50% external step electrical load reductions from full power operating conditions without reactor trip or lifting the steam generator safety valves. This is accomplished by bypassing the turbine and dumping steam directly to the condenser. The required capacity of the steam dump valves is 40% of the full load steam flow at full load steam pressure. This system flow requirement is achieved with 12 condenser dump valves.

The bounding minimum steam pressure (827 psia) which supports plant operation was identified in the T_{Hot} Reduction program. In order to ensure design load rejection capability at the reduced full power operating pressure certain steam dump controller setpoint changes were recommended for that program. These setpoint changes identified in WCAP-11388, Volume II, Section 3.0 also apply to the SGTP/TDF/PMTC Program conditions.

8.2 Condensate and Feedwater System

The increase in steam generator tube plugging level to 24% will have no adverse effects on the Condensate and Feedwater System. The increased plugging level poses no problem with respect to the design pressure and temperature and the flow rates in these systems. The overall feedwater mass flow rate may decrease slightly relative to the original plant operating conditions (15.03×10^6 lbm/hr vs. 15.13×10^6 lbm/hr), and since the final feedwater temperature remains the same (440°F), the volumetric feedwater flow rate may also decrease slightly in the increased tube plugging condition. The effects of the increased tube plugging levels on components in the Condensate and Feedwater System are discussed below.

8.2.1 Feedwater Isolation Valves (FIVs)

The rapid closure of these valves, as required for feedline isolation, causes a substantial thrust load on the feedwater isolation valves and the feedwater piping. The design loading conditions are not adversely impacted by the 24% increase in the SGTP level. Accordingly, design loads and associated stress resulting from rapid closure of the FIVs will not change.

8.2.2 Feedwater Control Valves

The full power steam pressure may decrease by as much as 163 psi (990 psia - 827 psia) for the T_{Hot} reduction 24% plugged tube condition compared to the original plant operating conditions. As concluded for the T_{Hot} Reduction Program (WCAP-11388), the turbine driven main feedwater pump speed control program will compensate for this decrease in steam generator pressure by lowering the rpm of the operating feedwater pumps. The end result will be that the pressure drop taken across the FCVs will be approximately the same as for the original plant operating conditions at any given power level. The full power feedwater flow rate through the valves at the reduced T_{Hot}, 24% SGTP condition may run slightly lower than the flow rate dictated by the original operating conditions (15.03×10^6 lbm/hr vs.

$15.13x10^6$ lbm/hr); however, the difference is small and should not affect system performance. From this it can be concluded that the FCVs will perform satisfactorily in the increased tube plugging condition.

As with the FIVs, rapid closure of the FCVs is required to mitigate certain transients and accidents. The design loading conditions for closure outlined above for the FIVs also apply to the FCVs. Accordingly, since the closure loading conditions are not adversely affected by going to the 24% SGTP level, the resultant design loads and associated stresses on the FCVs will not change.

8.3 Auxiliary Feedwater System

Operation with increased tube plugging levels of up to 24% will have no adverse impacts on the design or performance of the Auxiliary Feedwater System. The minimum auxiliary feedwater flow rates that must be delivered to the steam generators for transient and accident mitigation are based on reactor core power and the related proportional decay heat generated, and on certain other plant parameters such as plant metal and water volumes, and the water volumes assumed present in the steam generators at the time of the event. Since none of the above parameters has been adversely affected in going to the 24% SGTP levels, the minimum system flow requirements remain unchanged. As part of the current program, the effect of increasing the Main Steam Safety Valve setting tolerance to ±5% was evaluated. The impact of this proposed change on the Auxiliary Feedwater System is to reduce any system head margin available for delivering the required minimum flows. The effects of MSSV setting tolerance relaxation and increased tube plugging on the system components are discussed below.

8.3.1 Auxiliary Feedwater Pumps

The auxiliary feedwater pumps must be capable of delivering the minimum required flow rates to the intact steam generators within one minute of actuation and with the steam generators at a pressure equivalent to the set pressure of the lowest set steam generator safety valve plus 3% accumulation pressure. This ensures sufficient flow and relief capacity available to dissipate core decay heat following certain postulated steam generator heatup transients and accidents (eg. loss of main feedwater, SBLOCA). As discussed above, the minimum required auxiliary feedwater flow rates remain the same, and are not adversely impacted by the T_{Hot} reduction and increased tube plugging condition.

The auxiliary feedwater pumps consist of one 100% capacity electric motor-driven pump and one 100% capacity direct diesel engine driven pump. Operation of either pump is not impacted by the increase in SGTP levels.

8.3.2 Auxiliary Feedwater Storage Requirements

At Byron and Braidwood Units 1 and 2 a minimum volume of water must be kept in the condensate storage tank for exclusive use by the Auxiliary Feedwater System to accommodate a total loss of off-site power. The volume of water required is based on maintaining the RCS at hot standby for 9 hours following the above event. This required water volume is proportional to the decay heat which must be removed (which is directly related to the core power). Since, in the increased tube plugging condition, core power has not changed, the minimum condensate tank water storage volume that was considered adequate for the T_{Hot} Reduction Program will also be adequate for operation with SGTP levels of up to 24%.

Reference

8.0-1 WCAP-11388, "T_{Hot} Reduction Program Engineering Report for Byron Units 1 and 2, and Braidwood Units 1 and 2, May 1987."