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June 23, 1981

Director of Nuclear Reactor Regulation
Attention: Mr. Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: SEP Topics V-10.B, V-11.A, V-11.B, VI-7.C.1, VII-3, and VIII-2, R.E. Ginna Nuclear Power Plant Docket No. 50-244

References:

(1) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics, V-10.B, V-11.B, and VII-3 (Safe Shutdown Systems Report), May 13, 1981.

(2) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics V-11.A, V-11.B, and VI-7.C.1, dated April 24, 1981.

(3) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics VII-3 and VIII-2, dated April 2, 1981.

Dear Mr. Crutchfield:

This letter is in response to the SEP topic assessments provided in the three above-referenced letters. Due to the intimate relationship of the "Safe Shutdown" topics V-10.B, V-11.A, V-11.B and VII-3 addressed in these three letters, all of our comments are provided concurrently in the three attached responses. This should aid the inclusion of our comments into the NRC's "SEP Integrated Assessment".

Very truly yours,

John E. Maier

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Attachments

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Attachment 1: RG&E responses to NRC Assessment of SEP Topics V-10.B, RHR System Reliability, V-11.B, RHR Interlock Requirements, and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems report), May 13, 1981.

1. In RG&E's January 13, 1981 response to the NRC's November 14, 1980 "Safe Shutdown Systems" assessment, a number of comments were made which have not been incorporated into Revision 2 of this assessment, transmitted by letter dated May 13, 1981. We feel these comments were valid, and should be incorporated. For continuity, these comments will be listed below (with their original comment numbers):

"1. On page 5, Piping System Passive Failures, the NRC assumes piping system passive failures"...beyond those normally postulated by the staff, e.g., the catastrophic failure of moderate energy systems...". Although it is shown that safe shutdown following such an event could be achieved, it is not considered that such an evaluation should even be made. As noted by the staff, it is clearly beyond a reasonable design basis. It is thus recommended that this paragraph be deleted from the evaluation. Subsequent evaluations to this "criterion", such as those related to the CCW system on page 22 and 23, should also be deleted.

11. In paragraph g on page 66, it is noted that, when applying the power diversity requirements of BTP ASB 10-1 in event of an SSE, no means to supply feed to the steam generators exists. It was determined that this was acceptable, based on low likelihood of occurrence.

This conclusion is correct; however, since BPT ASB 10-1 does not consider an SSE in conjunction with the loss of all A.C. power, there is no need to even make the evaluation. The comparisons in the SEP program should be to current criteria, rather than to arguable extrapolations. Reference to loss of all A.C. power in conjuncton with an SSE should thus be deleted from this paragraph.

12. On page A-4, it is noted that additional systems are required to achieve cold shutdown for a PWR than for a BWR because of a difference in the definition of cold shutdown. This does not appear to be a reasonable basis. System requirements should be based on specific safety reasons. The NRC should be consistent in its requirements for cold shutdown, or provide a technical basis for any differences."

2. Staff position 1 states that "the licensee must develop plant operating/emergency procedures for conducting a plant shutdown and cooldown using only the systems and equipment identified in Section 3.1 of the SEP Safe Shutdown Systems Report." RG&E disagrees with the need for these procedures. We reiterate the comments provided in our January 13, 1981 response that the operator should perform a cooldown with the best equipment available to him at the time. If a piece of non-safety equipment is available, and would be the most beneficial for performing a required function, it is expected that this piece of equipment would be used. If it is not available, the operator could fall back on the use of safety-grade equipment. But RG&E does not intend to commit plant personnel to use only safety-related equipment, if non-safety equipment is available and more effective. We feel that it would be impossible to determine when a "safety-grade-only" cooldown procedure would ever be implemented. As long as the safety-grade equipment is available (and the safe shutdown assessment concudes that it is), RG&E considers that the necessary safety requirements are met.

   RG&E also notes that no regulatory basis for this requirement is provided. It is admitted in Section 4.5 of the Safe Shutdown report that "the need for procedures for these evaluations is <u>not</u> identified in Regulatory Guide 1.33...". Section 4.5 then goes on to say that the basis is found in BTP RSB 5-1 and SEP Topic VII-3. But BTP RSB 5-1 merely references RG 1.33, and this <u>is</u> the assessment of SEP Topic VII-3.

   Therefore, since no basis for this "requirement" exists, and we do not feel that it would even be beneficial, and since the Safe Shutdown report did conclude that the capability for attaining cold shutdown using only safety-related equipment exists, RG&E concludes that this staff position should be deleted from consideration.

3. Staff position 3 does not appear to take into account the information provided in our March 27, 1981 submittal regarding SEP Topic V-11.A. Enclosure 3 to that submittal provides the valve equipment specification, noting that the 700, 701, 720 and 721 MOV's are designed such that they physically are unable to open against a differential pressure of greater than 500 psi. This ensures that an intersystem LOCA caused by the opening of the outboard valves, plus leakage of the inboard valves, cannot occur, since the outboard valves cannot open.

Even without this provision, it is difficult to comprehend how the Ginna arrangement could result in an "Event V". By administrative procedure, the RHR valves are key-locked closed, with power removed. Further, interlocks are provided for the inboard RHR valves. Thus, for an "Event V" to occur would require the:

1) failure of the administrative procedure requiring power lock-out (at the breaker),

2) failure of the administrative procedure governing operation of the valve at power,

3) failure of the inboard isolation valve,

4) failure of the relief valve (RV 203) which has a capacity of 70,000 lb/hr at its 600 psig setpoint, to relieve the leakage past the inboard RHR valve.

This set of failures is considered very remote. When coupled with the fact that the RHR valve design prevents opening of the valves against a greater than 500 psi differential pressure, it is RG&E's conclusion that the possibility of an intersystem LOCA should not be a credible design basis. No additional modifications, such as diverse interlocks for the outboard valves, are warranted.

4. Staff position 5 states that "the operating procedures for the Ginna plant should be modified to direct the operator to cooldown and depressurize to RHR initiation parameters within 36 hours whenever the Service Water System is used for steam generator feedwater..." This position is based on the reference BNL-NUREG-28147, "Impure Water in Steam Generators and Isolation Condensers." We have had this report reviewed by NWT Corporation. NWT-167, "Use of Lake Ontario Water in Steam Generator During Hot Shutdown" (attached) concludes that, "although not recommended from the standpoint of maximizing component life, and operation for periods up to several days is not expected to result in any significant cracking or in deterioration of steam generator integrity."

RG&E therefore concludes that a specific directive to cool down and depressurize to RHR initiation conditions is not warranted, and should not be included in a procedure. The capability to do this does exist, however, and could be used if determined to be necessary at the time.

Attachment 2: RG&E responses to NRC letter of April 24, 1981 regarding SEP Topics V-11.A, "Isolation of High and Low Pressure Systems", V-11.B, "RHR Interlock Requirements", and VI-7.C.1, "Independence of Redundant Onsite Power Systems".

1. The Safety Evaluation for SEP Topic V-11.A, "Requirements for Isolation of High and Low Pressure Systems", specifies that the outboard RHR valves should have diverse interlocks to prevent opening when the RCS pressure is greater than RHR system design pressure.

   RG&E rationale for not providing these additional interlocks is provided in comment 3 of Attachment 1 of this transmittal.

2. The safety evaluation also required that interlocks be installed on the CVCS suction valves (200A, 200B, 202), to prevent a possible overpressurization of the CVCS letdown line outside containment. RG&E has noted in our March 27, 1981 letter on this SEP Topic that a relief valve (RV 203), with a capacity greater than the combined capacity of the three orifices, would relieve the pressure buildup caused by closure of the containment isolation valve 371. No overpressurization of the CVCS would thus be expected.

   RG&E has also evaluated the potential consequences of such an overpressurization event, with a subsequent small LOCA outside containment, and determined that no unacceptable consequences would result. This break would be a small LOCA outside containment (maximum flow of 140 gpm), and would be terminated by closure of valves 200A, 200B, and 202 either by operator action or automatically by low pressurizer level. Radiological consequences would be minimal, since no fuel damage would result. This event is specifically evaluated by SEP Topic XV-16, "Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment." RG&E has provided information concerning this topic by letter dated June 18, 1980 from L. D. White Jr. to Mr. Dennis M. Crutchfield.

   The RG&E conclusion is that, based on the availability of RV 203 to prevent overpressurization, together with the lack of unacceptable consequences due to an overpressurization, no interlocks or other modifications are required for the CVCS suction valves.

3. The safety evaluation further states that position indication is required on the CVCS discharge check valves. As stated in our March 27, 1981 letter on SEP Topic V-11.A, we do not believe that this line should be classified as a low pressure

system connected to the RCS, since the piping is 2500-lb piping throughout its length (to the positive displacement charging pump). RG&E has had no experience with failures of the positive displacement charging pump pistons to hold primary system pressure, nor would any failures be anticipated. Our contention that the charging line is not a line of concern is borne out by a memo from Edson G. Case to Raymond F. Fraley, "Isolation of Low Pressure Systems from Reactor Coolant System", dated July 11, 1977. That letter transmitted an NRC study of this subject to the ACRS, and evaluated all potential lines of concern. The charging line was not included.

To verify that the charging line was not a valid "Event V" concern, RG&E calculated the PWR Check Valve Event Tree (Section 4.4 of WASH-1400), using the charging line configuration (two in-series check valves and a charging pump piston). Very conservatively assuming that both check valves were undetected open, and that the probability of the charging pump piston failure was equal to a check valve failure, the $\overline{Q}_{SUM}$ calculated for this configuration was determined to be 1.4×10^{-8}/year. This is a low enough value to obviously be of no concern.

RG&E therefore considers that check valve position indication is not needed on the charging line check valves.

4. With respect to the SEP Topic Assessment V-11.B, no comments are necessary, since the resolution of outstanding issues is addressed in the topic assessment for SEP Topic V-11.A.

5. The additional information requested for SEP Topic VI-7.C.1 is presently being developed. It is anticipated that this information can be furnished to the NRC by July 15, 1981.

Attachment 3: RG&E responses to NRC letter of April 2, 1981, concerning SEP Topics VII-3, "Electrical, Instrumentation, and Control Feature of Systems Required for Safe Shutdown", and VIII-2, "Diesel Generators".

It appears that all comments provided by RG&E in our January 23, 1981 and January 30, 1981 letters concerning these topics have been properly incorporated.

Based on the resolution of all open items, and the removal of diesel generator testing from SEP Topic VIII-2, RG&E concludes that both of these topics are complete, with no outstanding issues to be carried into the Integrated Assessment.

NWT 167
February 1981

USE OF LAKE ONTARIO WATER IN STEAM GENERATORS DURING HOT SHUTDOWN

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INTRODUCTION

The possibility of using Lake Ontario water as an emergency PWR feedwater supply for more than 36 hours during which the plant would be brought to cold shutdown is being considered. The maximum steaming rate during such a period would be 100,000 pounds/h (200 gpm) at a temperature of 350°F. As a consequence of steaming, impurities of the untreated Lake Ontario water will concentrate in the steam generator. Of major concern is the possible risk of stress corrosion cracking (SCC) of steam generator materials in contact with the concentrated solution thus formed. To address this concern, the chemistry variation in the liquid phase as steaming proceeds at 350°F was estimated with emphasis on pH. Then, the possible potential for SCC was assessed on the basis of these estimates and available SCC data.

pH VARIATION AT 350°F UPON STEAMING LAKE ONTARIO WATER

A. Computer Modeling

The composition of Lake Ontario water as determined by RGE is given in Table 1.[1]

TABLE 1
LAKE ONTARIO WATER ANALYSIS
ppm

Calcium	35	Nitrate	2.5
Magnesium	8	Phosphate	0.3
Sodium	13	Fluoride	0.15
Potassium	3.6	Silica (as SiO_2)	0.25
Aluminum	0.1	Dissolved Oxygen	9.5
Chloride	32	Ammonia (as Nitrogen)	0.24
Sulfate	35		

Estimates of the water chemistry variation upon steaming were developed using the following assumptions:

1. Since aluminum and silica are in stoichiometric proportion in Lake Ontario water (Table 1), they are assumed to precipitate as aluminum silicate (clay) upon concentrating and therefore are removed from solution.

2. Since calcium occurs in the water (Table 1) in large excess over phosphate, it is assumed to precipitate all the phosphate as calcium hydroxy apatite ($Ca_5(PO_4)_3OH$) and remove it from the solution. The calcium in solution is decreased by the corresponding amount.

3. Fluoride and nitrite are assumed to behave as chloride. Potassium is assumed to behave as sodium.

4. Sodium and chloride in solution are assumed to remain completely dissociated.

5. Calcium carbonate precipitation is neglected. Degasification of CO_2 by steaming is assumed to occur.

6. The concentration of sodium and calcium chlorides is assumed limited by a solubility of 5 molal.

7. Chemical equilibrium expressions of references 2 and 3 apply.

On this basis, the liquid solution pH variation upon steaming at 350°F was estimated as a function of concentration factor defined as the mass ratio of total water (steam + liquid) to liquid water residual. The results are presented graphically in Figure 1. It is important to note that the definition of pH used here is that followed by Mesmer[4] in the determination of the dissociation constant of water at high temperatures, viz, the negative of the logarithm of the hydrogen ion concentration (not of its activity). Similarly, neutral pH is defined as that where the hydrogen and hydroxyl ion concentrations are equal. This neutral pH is a function of ionic strength. Therefore, the pH variation of the concentrated solutions must be considered in relation to that of neutral pH, also plotted in Figure 1. For basic solutions as is the case considered here, it is important to bear in mind that the hydroxyl ion concentration is expressed in terms of pH as follows:

$$C_{OH^-} = 10^{pH-2NpH}$$

(where NpH is the neutral pH value) and that when the neutral pH varies together with the ionic strength as the liquid solution is being concentrated upon steaming, the basicity of the solution may not be appreciated from the solution pH alone. The equivalent NaOH concentration is more suitable for this purpose and is plotted also in Figure 1.

B. Discussion

Steam Generator Bulk Water

Based on a maximum feed rate of 200 gpm to the steam generator and a total steam generator liquid volume of approximately 12,000 gallons, a maximum of one steam generator volume is steamed away each hour. Therefore, under maximum steaming conditions, the concentration factor achieved in the bulk steam generator water is t + 1 where t is the number of hours of steaming.

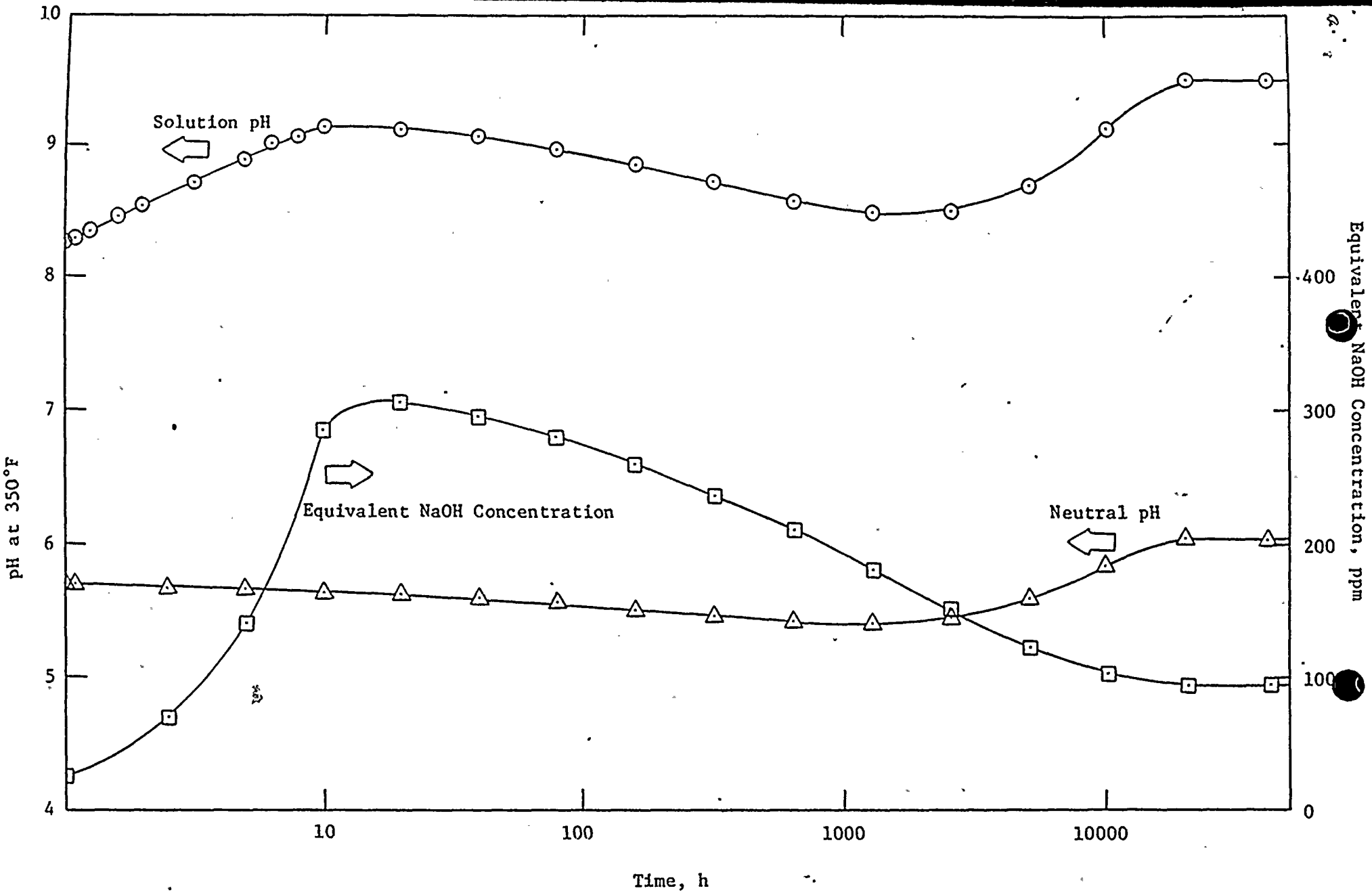

Figure 1. Variation of Steam Generator pH with Steaming at 350°F (feeding Lake Ontario water at 200 gpm)

The variation with time of the equivalent sodium hydroxide concentration in the steam generator with steaming of emergency Lake Ontario feedwater then can be followed on Figure 1. It is seen that a maximum equivalent NaOH concentration of about 300 ppm will be reached in the steam generator bulk water when 15 to 20 steam generator volumes will have been converted to steam, i.e., in approximately twenty hours. Further boiling should then decrease the equivalent NaOH concentration as magnesium and/or calcium hydroxides and/or calcium sulfate precipitate with increased concentrating. The decrease reaches a limit (at about 20,000 steam generator volumes converted to steam, i.e., in 20,000 hours) when sodium and calcium chlorides start to precipitate also. This limit is estimated at about 100 ppm equivalent NaOH for Lake Ontario water composition as specified in Table 1 and with the assumptions already stated. The assumptions seem reasonable and, at any rate, can be tested experimentally with a small autoclave from which known amounts of Lake Ontario water would be boiled away at 350°F at constant liquid level in the autoclave.

Crevices

The estimated equivalent NaOH solution concentration in steam generator crevices will depend upon the relative degree of crevice solution concentration above the bulk water. In tube to tube support plate crevices, there may be a distribution of relative concentration factors of unity and higher.

The chemistry in a crevice would lead that of the bulk in the sense that the chemistry of a specific crevice would travel the same curve (Figure 1) as the bulk but would be at a point on the curve somewhat ahead of the bulk. Since the causticity of Lake Ontario water is not a strong function of concentration, this does not pose a problem. Indeed it is expected in this case that after a short period of steaming, the crevice chemistry will be less basic than that of the bulk.

Cooling Water Composition

The NWT chemistry modeling work discussed herein is based on the chemical composition of Lake Ontario water summarized in Table 1 as supplied by RGE.

It is possible that seasonal changes in the characteristics of the lake water may result from the interrelation between source river flowrates, industrial pollution and/or acid rain. NWT has no relevant data to assess such effects.

It may be desirable that analyses made of Lake Ontario water during different seasons and under various conditions be fed into the NWT chemistry model. In this manner the safety of feeding Lake Ontario water, over the range of likely chemical compositions, can be verified.

POTENTIAL FOR SCC

A. Corrosion

The most aggressive solution expected based on the modeling work is 300 ppm NaOH, with ≤10 ppm O_2 (see below) at 350°F. Although laboratory data regarding these exact conditions are not available, data are available which can be extrapolated to assess the maximum corrosion rates expected for a given range of conditions.

van Rooyen and Kendig[5] cite Westinghouse data indicating that U-bends of Alloy 600 in deaerated 10% NaOH crack after several months of exposure. Figures 2 and 3 summarize Westinghouse tests[6] which show that at least 100 days of exposure to deaerated 10% NaOH at 600°F is required to produce a detectable crack in stressed Alloy 600.

Figure 4 shows data gathered by Berge and Donati.[7] These curves are for yield stressed C rings at 660°F. Extrapolating the curve for mill annealed Alloy 600 to 300 ppm NaOH yields a minimum time of 3500-4000 hours to induce a 0.5 millimeter crack.

The data presented above are for deaerated systems and are consistent with van Rooyen's[5] conclusion that Alloy 600 in 10% NaOH would not crack for several months. In the presence of oxygen, the susceptibility of Alloy 600 to SCC may be increased. Figure 5 shows stress corrosion behavior in 600°F high purity water containing varying amounts of oxygen in the gas phase above the water and adjusted to pH 10 at startup with ammonia.[8] As the oxygen content of the gas phase increased, the percent of the specimens attacked and extent of the attack increased. As noted in Figure 5 the average life in the 18-week test varied from no cracking with 1% oxygen in the gas phase (≤2 ppm oxygen in the water) to 7 weeks with 100% oxygen in the gas phase (≤200 ppm oxygen in the water).

McIlree and Michels[9] and later Sedriks, et al.,[10] reported less than 20% cracking after 27 days for Alloy 600 (2 common heat treatments) in aerated, 50% NaOH at 570°F.

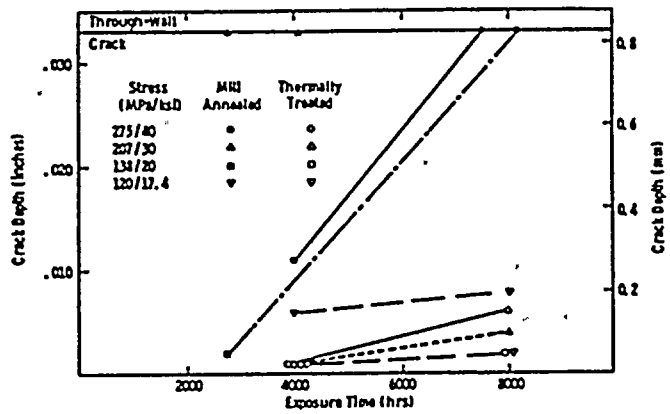

Figure 2. Crack Depth as a Function of Time, Stress Level and Material Condition for ID Pressurized Capsules Exposed to Deaerated 10% NaOH at 600°F[6].

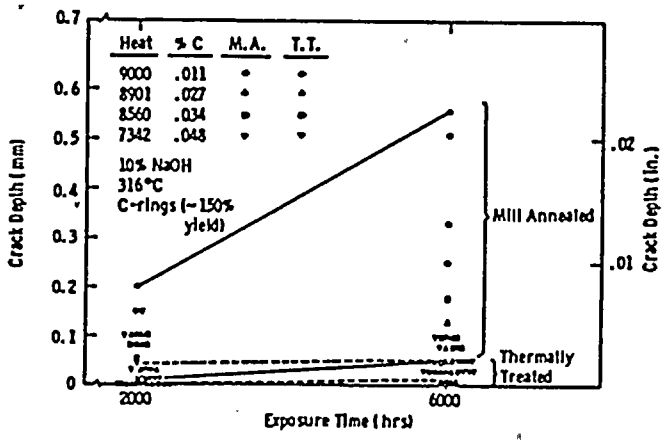

Figure 3. Crack Depth as a Function of Exposure Time for Mill Annealed and Thermally Treated Inconel Alloy 600 Exposed to Deaerated 10% NaOH at 600°F[6]

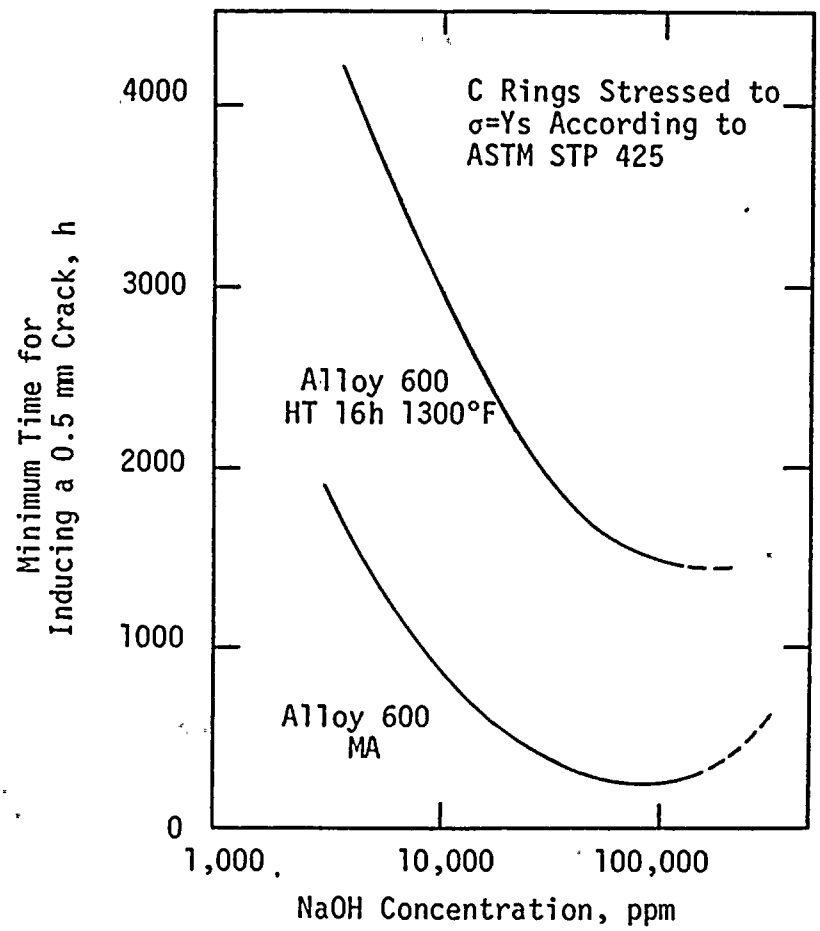

Figure 4. Resistance to Stress Corrosion Cracking of Alloy 600 Mill-Annealed or Heat Treated at 1300°F as a Function of Deaerated Sodium Hydroxide Concentration at 600°F[7]

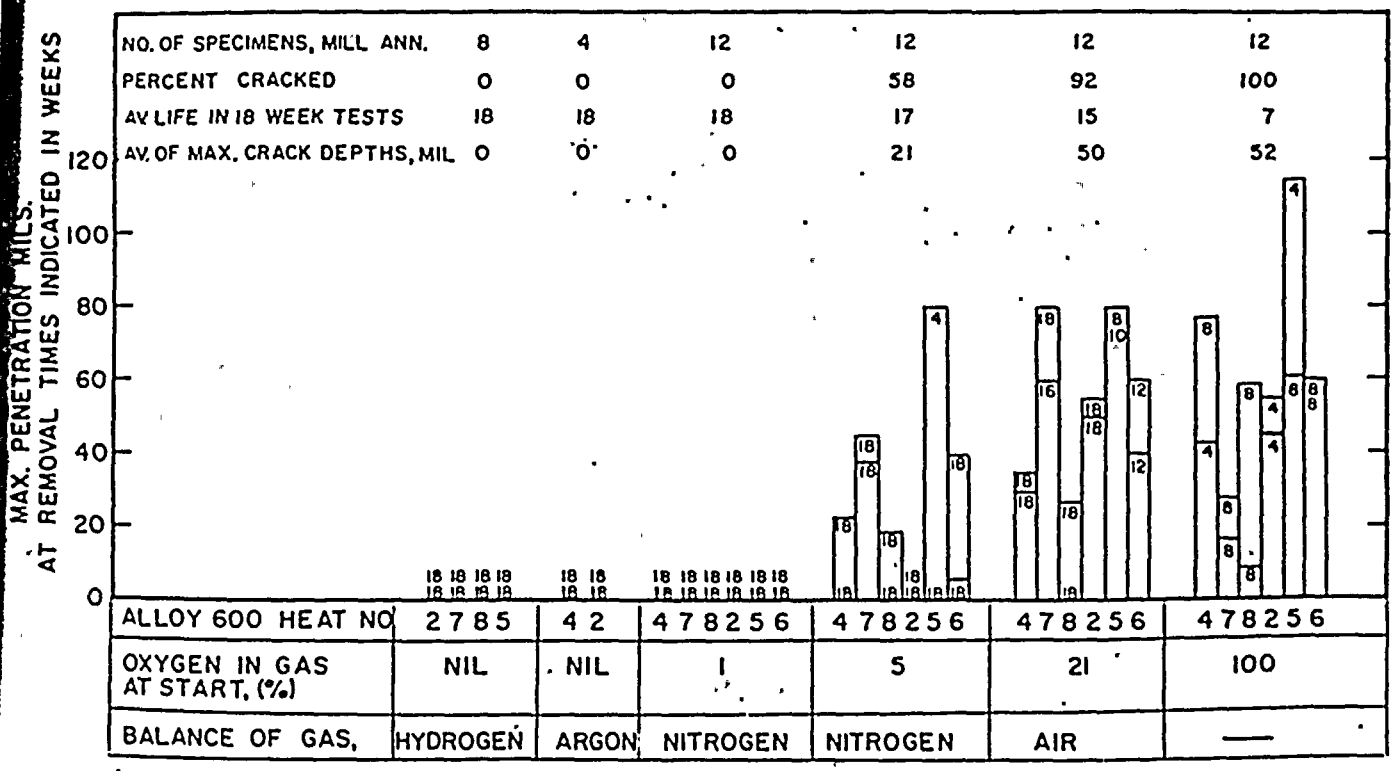

Figure 5. Stress Corrosion Behavior in Crevice Areas in Mill Annealed Inconel 600 Double U-bend Specimens in 600°F High Purity Water Adjusted to pH 10 with Ammonia at Startup[8]

Laboratory studies show that there is a significant temperature dependence of caustic stress corrosion cracking as illustrated in Figures 6 and 7. These results are for pressurized capsules exposed to 10% and 50% NaOH at varying stresses at temperatures ranging from 650 to 550°F. As can be seen, reducing the temperature below 600°F significantly extends the time for SCC to occur. This temperature dependence is further illustrated in Figure 8 where temperature is plotted versus rate constant for both 10% and 50% NaOH.

B. Oxygen

The lake water fed to the generators probably would be air saturated (approximately 10 ppm O_2). However, at 350°F the K_D (the equilibrium ratio between steam phase and liquid phase) for oxygen is slightly greater than 5000. Even though the dynamic distribution in practice may not reach true equilibrium conditions, the net effect of the high K_D value is that recriculated steam generator coolant will contain oxygen concentrations lower than 10 ppm. This recirculated coolant will dilute the oxygen concentration of incoming feedwater with a net oxygen level in the downcomer of $\sim$1 to 10 ppm, depending on the recirculation ratio under the contingency conditions.

C. Conclusion

With the significantly lower concentrations of sodium hydroxide (max 300 ppm), oxygen concentration $\leq$10 ppm and the lower temperature (350°F) involved, the contingency of feeding Lake Ontario water to the Ginna steam generators should result in no measureable damage to steam generator internals. Although not recommended from the standpoint of maximizing component life, such operation for periods up to several days is not expected to result in any significant cracking or in a deterioration of steam generator integrity.

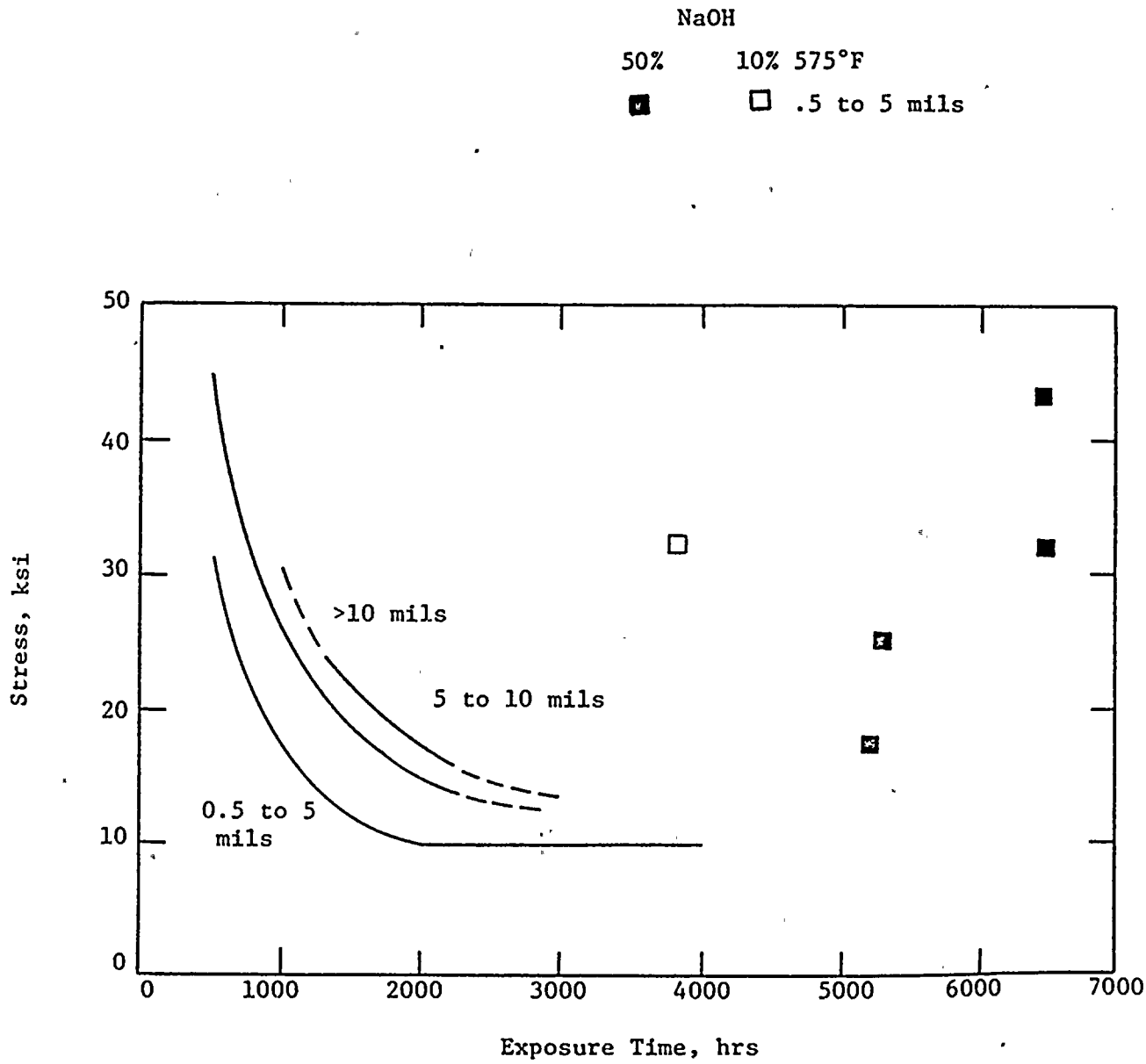

Figure 6. Caustic Cracking of Mill Annealed Alloy 600 at 575°F
(Lines depict zones of crack depth from 10% NaOH at 600°F)

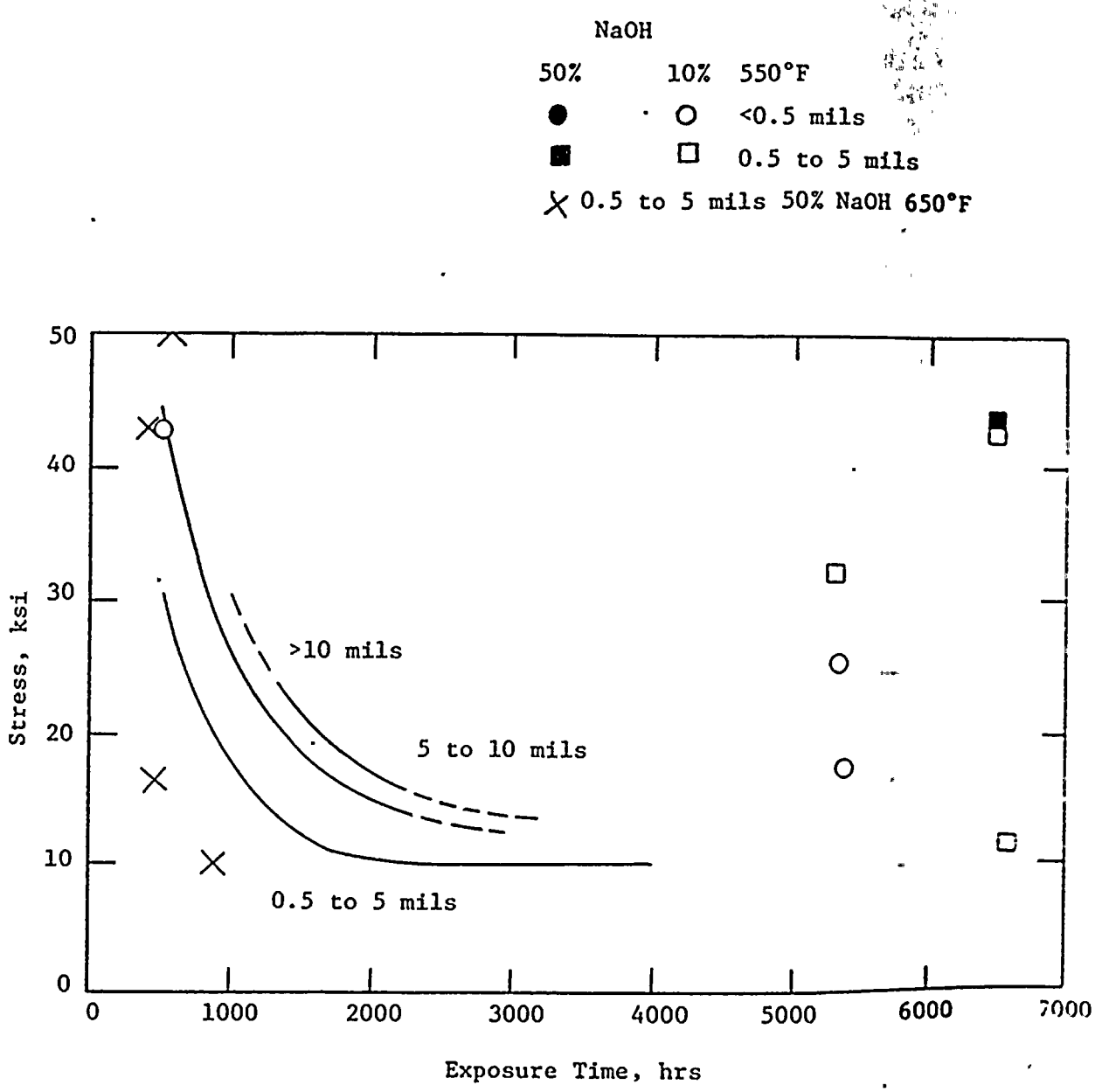

Figure 7. Caustic Cracking of Mill Annealed Alloy 600 at 550°F and 650°F (Lines depict zones of crack depth from 10% NaOH at 600°F)

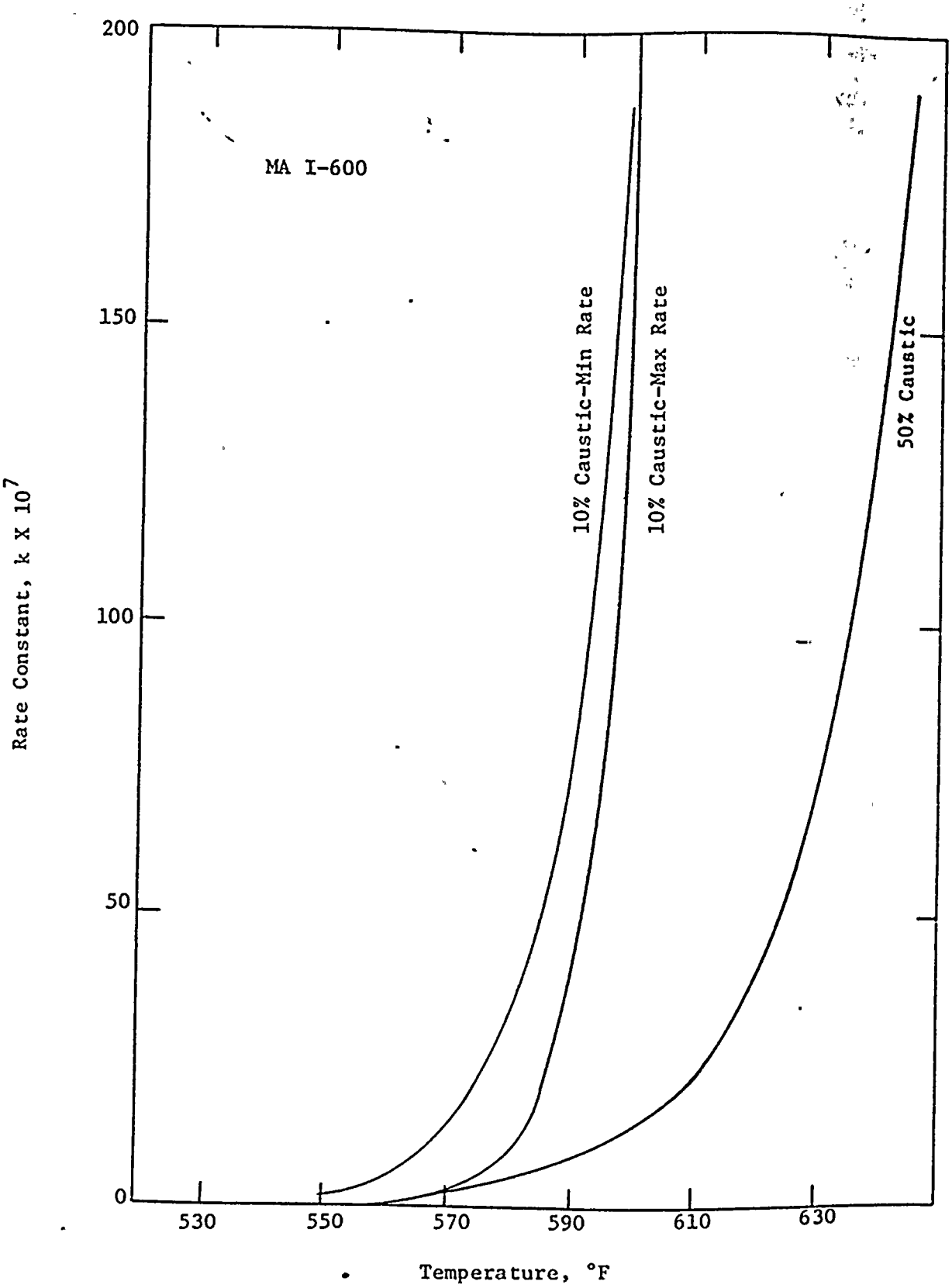

Figure 8. Indicated Variation in Rate of SCC with Temperature

COMMENTS ON VAN ROOYEN AND KENDIG'S REPORT[5]

The referenced report[5] basically is a broad summary covering a large volume of data applicable in part to stainless steels and in part to Alloy 600. We are generally in agreement with their nine summary conclusions, but find it difficult to apply their broad-brush treatment to the specifics of a PWR hot shutdown with lake water added to the steam generators at 350°F. Their document is misleading for such an application in two respects:

1. Caustic Concentration

Their statement that ..."For the purposes of SCC predictions, it has to be assumed that the time to form dangerous levels of NaOH, once impurities have been introduced, is short, i.e., one day or less" does not fully recognize the specific concentration chemistry of the cooling water involved nor the low heat flux available and the cutback in steaming rate during a period of hot shutdown. In the case of the Lake Ontario water, for example, the maximum NaOH concentration reached is 300 ppm (after steaming ~20 steam generator volumes) with a decrease in concentration thereafter.

2. Temperature

All of the test work referenced in the referenced report[5] was performed in the temperature range of 550 to 630°F. With the significant temperature dependence of caustic SCC as shown above, the concern at 350°F is many times less than is indicated from the data quoted by the authors.[5]

Based on the above three considerations, it is our assessment that the generalized time limit of 36 hours in the report[5] is not directly applicable to the Ginna steam generators steaming at 350°F while fed by Lake Ontario water.

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2. Leibovitz, J., and Sawochka, S. G., "Modeling the Effects of Condenser Inleakage on PWR Chemistry", presented at 41st Annual International Water Conference, Pittsburgh, Pennsylvania, October 1980.

3. Leibovitz, J. and Sawochka, S. G., "Modeling of Cooling Water Inleakage Effects in PWR Steam Generators, Topical Report, Research Project 404-1", Electric Power Research Institute, May 1980, to be published.

4. Mesmer, R. E., Baes, C. F., Jr., and Sweeton, F. M., "Boric Acid Equilibria and pH in PWR Coolants", Proceedings of the 32nd International Water Conference, Pittsburgh, Pennsylvania, November 1971, pp. 55-65.

5. van Rooyen, D., and Kendig, M. W., "Impure Water in Steam Generators and Isolation Generators", Brookhaven National Laboratory, June 1980 (Draft-BNL-NUREG-28147).

6. Airey, G. P., "Effect of Processing Variables on the Caustic Stress Corrosion Resistance of Inconel Alloy 600", presented at NACE Meeting, March 1979 (Paper Number 101).

7. Berge, Ph. and Donati, J. R., "Materials Requirements for Steam Generator Tubing", presented at International Conference on Materials Performance in Nuclear Steam Generators, St. Petersburg, Florida, October 1980.

8. Copson, H. R. and Economy, G., "Effect of Some Environmental Conditions on Stress Corrosion Behavior of Ni-Cr-Fe Alloys in Pressurized Water", Corrosion, 24, No. 3, pp. 55-65 (March 1968).

9. McIlree, A. R. and Michels, H. T., "Stress Corrosion Behavior of Fe-Cr-Ni and Other Alloys in High Temperature Caustic Solutions", Corrosion, 33, No. 2, pp. 60-67 (February 1977).

10. Sedriks, A. J., et al., "Inconel Alloy 690-A New Corrosion Resistant Material", Corrosion Engineering (Japan), 28, No. 2, pp. 82-95 (1979).

11. Burstein, S., WEPCO, ltr to H. R. Denton, NRC, dtd November 23, 1979, with attachments.

NWT 167
February 1981

USE OF LAKE ONTARIO WATER IN STEAM GENERATORS DURING HOT SHUTDOWN

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INTRODUCTION

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6. The concentration of sodium and calcium chlorides is assumed limited by a solubility of 5 molal.

7. Chemical equilibrium expressions of references 2 and 3 apply.

On this basis, the liquid solution pH variation upon steaming at 350°F was estimated as a function of concentration factor defined as the mass ratio of total water (steam + liquid) to liquid water residual. The results are presented graphically in Figure 1. It is important to note that the definition of pH used here is that followed by Mesmer[4] in the determination of the dissociation constant of water at high temperatures, viz, the negative of the logarithm of the hydrogen ion concentration (not of its activity). Similarly, neutral pH is defined as that where the hydrogen and hydroxyl ion concentrations are equal. This neutral pH is a function of ionic strength. Therefore, the pH variation of the concentrated solutions must be considered in relation to that of neutral pH, also plotted in Figure 1. For basic solutions as is the case considered here, it is important to bear in mind that the hydroxyl ion concentration is expressed in terms of pH as follows:

$$C_{OH^-} = 10^{pH-2NpH}$$

(where NpH is the neutral pH value) and that when the neutral pH varies together with the ionic strength as the liquid solution is being concentrated upon steaming, the basicity of the solution may not be appreciated from the solution pH alone. The equivalent NaOH concentration is more suitable for this purpose and is plotted also in Figure 1.

8. Discussion

Steam Generator Bulk Water

Based on a maximum feed rate of 200 gpm to the steam generator and a total steam generator liquid volume of approximately 12,000 gallons, a maximum of one steam generator volume is steamed away each hour. Therefore, under maximum steaming conditions, the concentration factor achieved in the bulk steam generator water is t + 1 where t is the number of hours of steaming.

The variation with time of the equivalent sodium hydroxide concentration in the steam generator with steaming of emergency Lake Ontario feedwater then can be followed on Figure 1. It is seen that a maximum equivalent NaOH concentration of about 300 ppm will be reached in the steam generator bulk water when 15 to 20 steam generator volumes will have been converted to steam, i.e., in approximately twenty hours. Further boiling should then decrease the equivalent NaOH concentration as magnesium and/or calcium hydroxides and/or calcium sulfate precipitate with increased concentrating. The decrease reaches a limit (at about 20,000 steam generator volumes converted to steam, i.e., in 20,000 hours) when sodium and calcium chlorides start to precipitate also. This limit is estimated at about 100 ppm equivalent NaOH for Lake Ontario water composition as specified in Table 1 and with the assumptions already stated. The assumptions seem reasonable and, at any rate, can be tested experimentally with a small autoclave from which known amounts of Lake Ontario water would be boiled away at 350°F at constant liquid level in the autoclave.

Crevices

The estimated equivalent NaOH solution concentration in steam generator crevices will depend upon the relative degree of crevice solution concentration above the bulk water. In tube to tube support plate crevices, there may be a distribution of relative concentration factors of unity and higher.

The chemistry in a crevice would lead that of the bulk in the sense that the chemistry of a specific crevice would travel the same curve (Figure 1) as the bulk but would be at a point on the curve somewhat ahead of the bulk. Since the causticity of Lake Ontario water is not a strong function of concentration, this does not pose a problem. Indeed it is expected in this case that after a short period of steaming, the crevice chemistry will be less basic than that of the bulk.

Cooling Water Composition

The NWT chemistry modeling work discussed herein is based on the chemical composition of Lake Ontario water summarized in Table 1 as supplied by RGE.

POTENTIAL FOR SCC

A. Corrosion

The most aggressive solution expected based on the modeling work is 300 ppm NaOH, with ≤10 ppm O_2 (see below) at 350°F. Although laboratory data regarding these exact conditions are not available, data are available which can be extrapolated to assess the maximum corrosion rates expected for a given range of conditions.

van Rooyen and Kendig[5] cite Westinghouse data indicating that U-bends of Alloy 600 in deaerated 10% NaOH crack after several months of exposure. Figures 2 and 3 summarize Westinghouse tests[6] which show that at least 100 days of exposure to deaerated 10% NaOH at 600°F is required to produce a detectable crack in stressed Alloy 600.

Figure 4 shows data gathered by Berge and Donati.[7] These curves are for yield stressed C rings at 660°F. Extrapolating the curve for mill annealed Alloy 600 to 300 ppm NaOH yields a minimum time of 3500-4000 hours to induce a 0.5 millimeter crack.

The data presented above are for deaerated systems and are consistent with van Rooyen's[5] conclusion that Alloy 600 in 10% NaOH would not crack for several months. In the presence of oxygen, the susceptibility of Alloy 600 to SCC may be increased. Figure 5 shows stress corrosion behavior in 600°F high purity water containing varying amounts of oxygen in the gas phase above the water and adjusted to pH 10 at startup with ammonia.[8] As the oxygen content of the gas phase increased, the percent of the specimens attacked and extent of the attack increased. As noted in Figure 5 the average life in the 18-week test varied from no cracking with 1% oxygen in the gas phase (≤2 ppm oxygen in the water) to 7 weeks with 100% oxygen in the gas phase (≤200 ppm oxygen in the water).

McIlree and Michels[9] and later Sedriks, et al.,[10] reported less than 20% cracking after 27 days for Alloy 600 (2 common heat treatments) in aerated, 50% NaOH at 570°F.

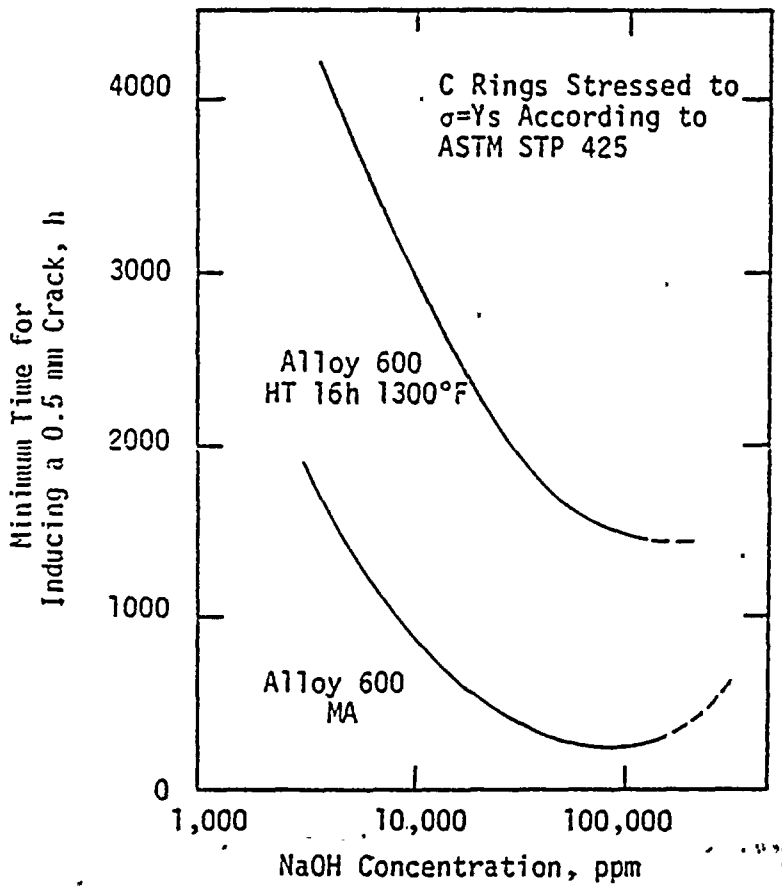

Figure 4. Resistance to Stress Corrosion Cracking of Alloy 600 Mill-Annealed or Heat Treated at 1300°F as a Function of Deaerated Sodium Hydroxide Concentration at 600°F[7]

Laboratory studies show that there is a significant temperature dependence of caustic stress corrosion cracking as illustrated in Figures 6 and 7. These results are for pressurized capsules exposed to 10% and 50% NaOH at varying stresses at temperatures ranging from 650 to 550°F. As can be seen, reducing the temperature below 600°F significantly extends the time for SCC to occur. This temperature dependence is further illustrated in Figure 8 where temperature is plotted versus rate constant for both 10% and 50% NaOH.

B. Oxygen

The lake water fed to the generators probably would be air saturated (approximately 10 ppm O_2). However, at 350°F the K_D (the equilibrium ratio between steam phase and liquid phase) for oxygen is slightly greater than 5000. Even though the dynamic distribution in practice may not reach true equilibrium conditions, the net effect of the high K_D value is that recriculated steam generator coolant will contain oxygen concentrations lower than 10 ppm. This recirculated coolant will dilute the oxygen concentration of incoming feedwater with a net oxygen level in the downcomer of ~1 to 10 ppm, depending on the recirculation ratio under the contingency conditions.

C. Conclusion

With the significantly lower concentrations of sodium hydroxide (max 300 ppm), oxygen concentration ≤10 ppm and the lower temperature (350°F) involved, the contingency of feeding Lake Ontario water to the Ginna steam generators should result in no measureable damage to steam generator internals. Although not recommended from the standpoint of maximizing component life, such operation for periods up to several days is not expected to result in any significant cracking or in a deterioration of steam generator integrity.

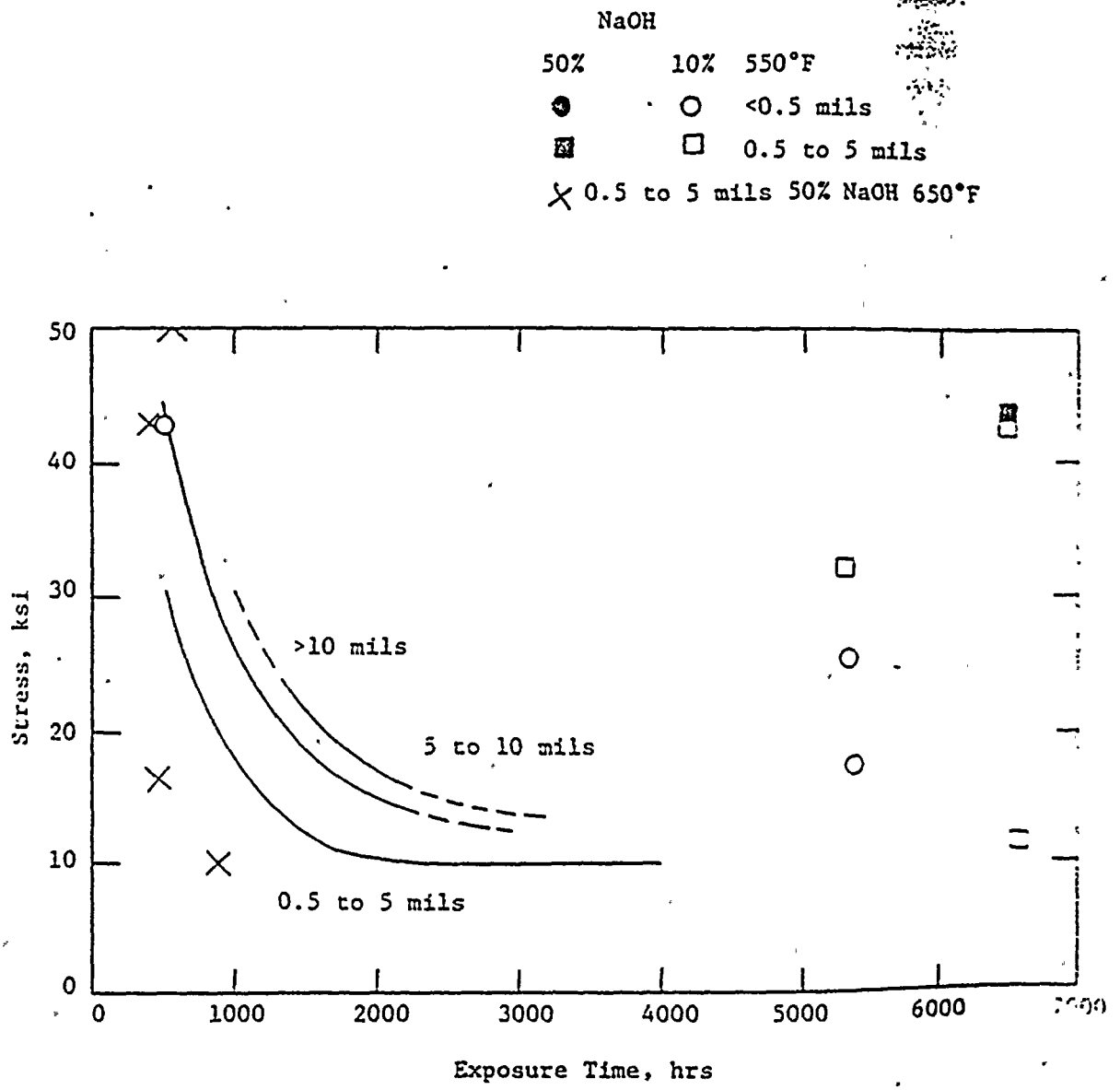

Figure 7. Caustic Cracking of Mill Annealed Alloy 600 at 550°F and 650°F (Lines depict zones of crack depth from 10% NaOH at 600°F)

COMMENTS ON VAN ROOYEN AND KENDIG'S REPORT[5]

The referenced report[5] basically is a broad summary covering a large volume of data applicable in part to stainless steels and in part to Alloy 600. We are generally in agreement with their nine summary conclusions, but find it difficult to apply their broad-brush treatment to the specifics of a PWR hot shutdown with lake water added to the steam generators at 350°F. Their document is misleading for such an application in two respects:

1. Caustic Concentration

Their statement that ..."For the purposes of SCC predictions, it has to be assumed that the time to form dangerous levels of NaOH, once impurities have been introduced, is short, i.e., one day or less" does not fully recognize the specific concentration chemistry of the cooling water involved nor the low heat flux available and the cutback in steaming rate during a period of hot shutdown. In the case of the Lake Ontario water, for example, the maximum NaOH concentration reached is 300 ppm (after steaming ~20 steam generator volumes) with a decrease in concentration thereafter.

2. Temperature

All of the test work referenced in the referenced report[5] was performed in the temperature range of 550 to 630°F. With the significant temperature dependence of caustic SCC as shown above, the concern at 350°F is many times less than is indicated from the data quoted by the authors.[5]

Based on the above three considerations, it is our assessment that the generalized time limit of 36 hours in the report[5] is not directly applicable to the Ginna steam generators steaming at 350°F while fed by Lake Ontario water.

R Scholl

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

April 24, 1981

Docket No. 50-244
LS05-81- 04-035

Mr. John E. Maier
Vice President
Electric and Steam Production
Rochester Gas & Electric Corporation
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Dear Mr. Maier:

SUBJECT: SEP TOPICS V-11.A, ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS, V-11.B, RHR INTERLOCK REQUIREMENTS AND VI-7.C.1, INDEPENDENCE OF REDUNDANT ONSITE POWER SYSTEMS - R. E. GINNA NUCLEAR POWER PLANT

We have reviewed your letter of March 27, 1981 and agree with resolving open items during topic evaluations rather than deferring a decision to the Integrated Assessment. To this end, we are enclosing a revised safety evaluation of Topic V-11.A.

We have also reviewed your comments on the draft Technical Evaluation Report (TER) SEP Topic V-11.B dated January 8, 1981. Your comments on SEP Topic V-11.B are covered by Sections 3.1 and 3.2 of our safety evaluation on SEP Topic V-11.A. We are enclosing a revised Technical Evaluation Report on Topic V-11.B which incorporates a reference to Section 3.1 and 3.2 of our safety evaluation report on Topic V-11.A.

We are enclosing a request for additional information on SEP Topic VI-7.C.1 where we do not have sufficient information to reach an independent safety assessment.

Sincerely,

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Licensing

Enclosure:
SER for SEP Topic V-11.A
Questions for SEP Topic VI-7.C.1

cc w/enclosure:
See next page

SAFETY EVALUATION

TOPIC: V-11.A Requirements for Isolation of High and Low Pressure Systems

Several systems that have a relatively low design pressure are connected to the reactor coolant pressure boundary. The valves that form the interface between the high and low pressure systems must have sufficient redundancy and interlocks to assure that the low pressure systems are not subjected to coolant pressures that exceed design limits. The problem is complicated since under certain operating modes (e.g., shutdown cooling and ECCS injection) these valves must open to assure adequate reactor safety.

As noted in EG&G Report 1285 (Appendix A), Ginna has three systems with a lower design pressure rating than the RCS, that are directly connected to the RCS. The RHR, SIS, and CVCS system do not meet current licensing requirements for isolation of high and low pressure systems as specified below.

(1) The RHR system is not in compliance with the current licensing requirements of BTP RSB 5-1 since none of the isolation valves will automatically close if RCS pressure exceeds RHR design pressure. Also, the outboard isolation valves have no interlocks to prevent RHR overpressurization, and the inboard valve interlocks are neither diverse nor independent.

(2) The SIS is not in compliance with the current licensing requirements of SRP 6.3 since the MOVs in the low pressure injection lines have no interlocks to prevent opening where the RCS pressure and the single check valve in each line is not tested.

(3) The CVCS is not in compliance with current licensing requirements for isolation of high and low pressure systems contained in BTP EICSB-3 since the suction and discharge line solenoid-operated valves have no interlocks to prevent system overpressurization, and the discharge line check valves have no position indication available in the control room.

Because of the severe consequences of a LOCA outside of containment and the lack of assurance that these isolation valves could be closed against significant flow under the resulting environmental conditions, the RHR isolation valves and the CVCS suction valves should be modified to satisfy the functional requirements of BTP RSB 5-1 and BTP EICSB-3. The modifications of this equipment should meet current criteria for seismic and environmental qualification. The schedule for installing these modifications will be determined during the integrated assessment portion of our review.

The basis for requiring diverse interlocks in the RHR outboard isolation valves is that, if an operator opens the outboard valve and the inboard valve leaks, an uncontrolled LOCA outside of containment (Event V) could possibly occur.

The basis for not requiring interlocks in the low pressure injection system is that, since the contractor's report was published, a check valve test program has been established, and thus, the system now satisfies the single failure criterion.

The basis for requiring the interlocks on the suction and position indication on the discharge check valves in the CVCS system is that a failure of the relief valve to function when required may lead to overpressurization and a subsequent event V.

The basis for not requiring interlocks on the CVCS discharge valves is that the check valves in series with the positive displacement pumps satisfy the single failure criterion as long as check valve position is known and the pump capacity is verified periodically.

As previously noted, in our systems safety evaluation of SEP Topic V-10.B, it is not necessary to close the RHR valves automatically on increasing reactor coolant system pressure during startup because of the overpressurization protection system. (See also Topic V-3.)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FEB 17 1981

Docket No. 50-244
LS05-81-02-060

Mr. John E. Maier
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Rochester Gas & Electric Corporation
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Dear Mr. Maier:

RE: SEP TOPICS V-II.A, ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS, AND VI-7.C.1, INDEPENDENCE OF REDUNDANT ONSITE POWER SYSTEMS - R.E. GINNA NUCLEAR POWER PLANT

Enclosed are final evaluations of SEP Topics V-II.A and VI-7.C.1 for R.E. Ginna Nuclear Power Plant. These assessments compare your facility, as described in Docket No. 50-244, with the criteria currently used by the regulatory staff for licensing new facilities. These reports have been revised to reflect the factual comments provided by your January 8, 1981 letter.

Your observations with regard to the acceptability of alternative designs and the use of administrative controls will be considered during our preparation of the integrated safety assessment for your plant. However, it must be pointed out that the currently approved version of Regulatory Guide 1.139 is Revision 0. Revision 0 requires diverse interlocks.

These evaluations will be basic inputs to the integrated safety assessment for your facility. As previously stated, these assessments may be revised in the future if your facility design is changed or if NRC criteria relating to this subject are modified before the integrated assessment is completed.

Sincerely,

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
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SEP TECHNICAL EVALUATION

TOPIC V-11.A
ELECTRICAL, INSTRUMENTATION, AND CONTROL FEATURES FOR ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS

FINAL DRAFT

R. E. GINNA NUCLEAR STATION

Docket No. 50-244

January 1981

S. E. Mays

1-26-81

CONTENTS

SEP TECHNICAL EVALUATION

TOPIC V-11.A
ELECTRICAL, INSTRUMENTATION, AND CONTROL FEATURES FOR ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS

FINAL DRAFT

R. E. GINNA NUCLEAR STATION

1.0 INTRODUCTION

The purpose of this review is to determine if the electrical, instrumentation, and control (EI&C) features used to isolate systems with a lower pressure rating than the reactor coolant primary system are in compliance with current licensing requirements as outlined in SEP Topic V-11A. Current guidance for isolation of high and low pressure systems is contained in Branch Technical Position (BTP) EICSB-3, BTP RSB-5-1, and the Standard Review Plant (SRP), Section 6.3.

2.0 CRITERIA

2.1 Residual Heat Removal (RHR) Systems. Isolation requirements for RHR systems contained in BTP RSB-5-1 are:

1. The suction side must be provided with the following isolation features:

   a. Two power-operated valves in series with position indicated in the control room.

   b. The valves must have independent and diverse interlocks to prevent opening if the reactor coolant system (RCS) pressure is above the design pressure of the RHR system.

   c. The valves must have independent and diverse interlocks to ensure at least one valve closes upon an increase in RCS pressure above the design pressure of the RHR system.

2. The discharge side must be provided with one of the following features:

   a. The valves, position indicators, and interlocks described in (1)(a) through (1)(c) above.

b. One or more check valves in series with a normally-closed power-operated valve which has its position indicated in the control room. If this valve is used for an Emergency Core Cooling System (ECCS) function, the valve must open upon receipt of a safety injection signal (SIS) when RCS pressure has decreased below RHR system design pressure.

c. Three check valves in series.

d. Two check valves in series, provided that both may be periodically checked for leak tightness and are checked at least annually.

2.2 Emergency Core Cooling System. Isolation requirements for ECCS are contained in SRP 6.3. Isolation of ECCS to prevent overpressurization must meet one of the following features:

1. One or more check valves in series with a normally-closed motor-operated valve (MOV) which is to be opened upon receipt of a SIS when RCS pressure is less than the ECCS design pressure

2. Three check valves in series

3. Two check valves in series, provided that both may be periodically checked for leak tightness and are checked at least annually.

2.3 Other Systems. All other low pressure systems interfacing with the RCS must meet the following isolation requirements from BTP EICSB-3:

1. At least two valves in series must be provided to isolate the system when RCS pressure is above the system design pressure and valve position should be provided in the control room

2. For systems with two MOVs, each MOV should have independent and diverse interlocks to prevent opening until RCS pressure is below the system design pressure and should automatically close when RCS pressure increases above system design pressure

3. For systems with one check valve and a MOV, the MOV should be interlocked to prevent opening if RCS

pressure is above system design pressure and should automatically close whenever RCS pressure exceeds system design pressure.

3.0 DISCUSSION AND EVALUATION

There are three systems at R. E. Ginna Nuclear Station which have a direct interface with the RCS pressure boundary and have a design pressure rating of all or part of the system which is less than that of the RCS. These systems are the Chemical and Volume Control System (CVCS), the Safety Injection System (SIS), and the Residual Heat Removal (RHR) system.

3.1 Residual Heat Removal System. The RHR system takes a suction on the RCS loop A hot leg, circulates the water through the RHR system heat exchanger, and discharges to the RCS loop B cold leg. Two motor-operated valves in series provide isolation capabilities in both the suction and discharge lines. Each of these MOVs has position indication in the control room. The inboard (closest to the RCS) valves are interlocked to prevent opening if RCS pressure is above RHR system design pressure. However, both valves use the same pressure switch and relay to provide this interlock. The outboard valves have no pressure interlocks. None of the valves will automatically close if RCS pressure increases above RHR system design pressure during RHR system operation.

The RHR system is not in compliance with the current licensing requirements of BTP RSB-5-1 since none of the isolation valves will automatically close if RCS pressure exceeds RHR design pressure. Also, the outboard isolation valves have no interlocks to prevent RHR overpressurization, and the inboard valve interlocks are neither diverse nor independent.

3.2 Safety Injection System. One SIS subsystem consists of two accumulators pressurized with nitrogen with each accumulator isolated from the RCS by a pair of check valves. There are connections upstream of each check valve that can allow them to be tested. A normally-open

motor-operated isolation valve upstream of the check valves for each accumulator has position indication in the control room. Each MOV is opened automatically, if closed, upon receipt of a safety injection signal.

The second SIS subsystem consists of two loops, each supplied by a safety injection pump. Each pump discharges to the hot and cold legs of one RCS loop. Isolation is provided by two check valves in series for each branch of the safety injection loop. The cold leg check valves are testable. The check valves in the lines supplying the RCS hot leg for each SIS loop are not testable. However, the MOV in each hot leg is locked shut with power removed and is not required for accident mitigation. A motor-operated isolation valve with position indication in the control room is provided in each branch of the cold leg discharge lines. These valves open upon receipt of a safety injection signal, but have no interlocks preventing opening when RCS pressure is above SIS design pressure.

The third SIS subsystem uses the RHR system to provide low pressure water from the refueling water storage tank to the reactor vessel head (core deluge). Isolation is provided by a MOV in series with a check valve in each of two branches. The MOVs open upon receipt of a safety injection signal but have no interlocks to prevent opening when RCS pressure is above SIS design pressure.

The SIS is not in compliance with the current licensing requirements of SRP 6.3 since the MOVs for the low pressure injection lines have no interlocks to prevent opening when RCS pressure exceeds SIS design pressure.

3.3 <u>Chemical and Volume Control System</u>. The CVCS takes water from the RCS and passes it through a regenerative heat exchanger, an orifice to reduce its pressure, and a nonregenerative heat exchanger before reducing its pressure further by the use of a pressure control valve. After filtering and cleanup, the water may be returned to the RCS by the use of the charging pumps, which increase the water pressure

and pass it through the regenerative heat exchanger to either the hot or cold legs of the RCS or to the pressurizer auxiliary spray line.

The CVCS suction line isolation is provided by a manually-operated solenoid valve in series with three parallel solenoid-operated valves. Each of these valves is operated from the control room and has valve position indicated. None of the valves have interlocks to prevent opening or to automatically close if the pressure exceeds the design rating of the low pressure portions of the system.

The CVCS discharge line isolation is provided by a common discharge line check valve and a branch check valve in each of the three branches downstream of the common check valve. Drain fittings on the discharge line upstream of each check valve can allow the valves to be tested. There is no position indication available in the control room for the check valves. There are solenoid isolation valves in each discharge line branch which have position indication in the control room, but these valves have no interlocks to prevent system overpressurization.

The CVCS is not in compliance with current licensing requirements for isolation of high and low pressure systems contained in BTP EICSB-3 since the suction line solenoid-operated valves have no interlocks to prevent system overpressurization, and the discharge line check valves have no position indication available in the control room.

4.0 SUMMARY

The R. E. Ginna Nuclear Station has three systems with a lower design pressure rating than the RCS, which are directly connected to the RCS. The CVCS, SIS, and RHR system do not meet current licensing requirements for isolation of high and low pressure systems as specified below.

1. The CVCS solenoid-operated valves have no pressure-related interlocks, and the discharge line check valves have no position indication available in the control room as required by BTP EICSB-3

2. The MOVs in the low pressure SIS lines have no pressure-related interlocks required by SRP 6.3

3. None of the RHR system isolation valves automatically close if RCS pressure increases above RHR system design pressure during RHR system operation, and the outboard isolation valves have no pressure-related interlocks as required by BTP RSB-5-1. The interlocks for the inboard isolation valves are neither diverse nor independent.

5.0 REFERENCES

1. NUREG-075/087, Branch Technical Positions EICSB-3, RSB-5-1; Standard Review Plan 6.3.

2. Updated Final Facility Description and Safety Analysis Report, Ginna Nuclear Power Plant, Unit No. 1.

3. RG&E drawings 33013-422, -424, -425, -426, -427, -428, -432, -433, -434, -435, and -436.

4. RG&E drawings 10905-280, -285, -287, -295, -296, -300, and -301.

TOPIC V-11.B(SYSTEMS)

SEE TOPIC V-10.A

P Schoell

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

April 24, 1981

Docket No. 50-244
LS05-81- 04-035

Mr. John E. Maier
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89 East Avenue
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Dear Mr. Maier:

SUBJECT: SEP TOPICS V-11.A, ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS, V-11.B, RHR INTERLOCK REQUIREMENTS AND VI-7.C.1, INDEPENDENCE OF REDUNDANT ONSITE POWER SYSTEMS - R. E. GINNA NUCLEAR POWER PLANT

We have reviewed your letter of March 27, 1981 and agree with resolving open items during topic evaluations rather than deferring a decision to the Integrated Assessment. To this end, we are enclosing a revised safety evaluation of Topic V-11.A.

We have also reviewed your comments on the draft Technical Evaluation Report (TER) SEP Topic V-11.B dated January 8, 1981. Your comments on SEP Topic V-11.B are covered by Sections 3.1 and 3.2 of our safety evaluation on SEP Topic V-11.A. We are enclosing a revised Technical Evaluation Report on Topic V-11.B which incorporates a reference to Section 3.1 and 3.2 of our safety evaluation report on Topic V-11.A.

We are enclosing a request for additional information on SEP Topic VI-7.C.1 where we do not have sufficient information to reach an independent safety assessment.

Sincerely,

Dennis M. Crutchfield

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Questions for SEP Topic VI-7.C.1

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SYSTEMATIC EVALUATION PROGRAM REVIEW OF NRC SAFETY TOPIC V-11.B ASSOCIATED WITH THE ELECTRICAL, INSTRUMENTATION, AND CONTROL PORTIONS OF THE RESIDUAL HEAT REMOVAL SYSTEM FOR THE GINNA NUCLEAR POWER PLANT

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ABSTRACT

This report documents the technical evaluation and review of NRC safety topic V-11.B, associated with the electrical, instrumentation, and control portions of the residual heat removal (RHR) system for the Ginna nuclear power plant. Current licensing criteria are used to evaluate the overpressure protection and independence of the RHR system.

FOREWORD

This report is supplied as part of the Systematic Evaluation Program being conducted for the U.S. Nuclear Regulatory Commission by Lawrence Livermore National Laboratory. The work was performed by EG&G, Energy Measurements Group, San Ramon Operations for Lawrence Livermore National Laboratory under U.S. Department of Energy contract number DE-AC08-76NV01183.

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1. INTRODUCTION

A number of plants have residual heat removal (RHR) systems in which the design pressure rating is lower than the reactor coolant system (RCS) pressure boundary to which the system is connected. The RHR system normally is located outside of primary containment and has motor-operated valves (MOVs) which isolate it from the RCS. There is, therefore, a potential that these systems would be subjected to pressure stresses in excess of their design rating if the isolation MOVs were opened inadvertently while the RCS was above the RHR system design pressure rating. This could result in a LOCA outside containment and a loss of reflood capability since the coolant inventory could be lost. Generally, interlocks are provided to prevent isolation MOVs from opening under high RCS pressure conditions.

It is important to incorporate features into the system design which will prevent overpressurizing the low pressure-rated RHR systems which interface with the reactor coolant pressure boundary. The current licensing criteria requires redundant, diverse interlocks to prevent opening of the isolation MOVs when RCS pressure exceeds RHR pressure design

limits. The current licensing criteria also requires automatic closure of the isolation MOVs when RCS exceeds RHR pressure design limits.

The objective of this review is to ensure that the plant has adequate measures to protect a low pressure-rated RHR system that interfaces with the RCS from failures due to excessive pressure and that such protection is suitably redundant and diverse.

This review applies to the interlocks associated with the isolation MOVs of the RHR system. Other protection schemes such as double-testable check valves are discussed in reports on other NRC Safety Topics.

2. CURRENT LICENSING CRITERIA

Branch Technical Position ICSB-3 [Ref. 1], entitled "Isolation of Low Pressure Systems from the High Pressure RCS," states that:

> The isolation MOVs should have independent and diverse interlocks to prevent opening unless the primary system pressure is below the subsystem design pressure. Also, the isolation MOV operators should receive a signal to close the valves automatically when the primary system pressure exceeds the subsystem design pressure.

Branch Technical Position RSB 5-1 [Ref. 2], entitled "Design Requirements for the Residual Heat Removal System," states that:

> Isolation shall be provided by at least two power-operated valves in series, and the valves shall have independent diverse interlocks to prevent the valves from being opened unless the RCS pressure is below the RHR system design pressure. The valves shall have independent, diverse interlocks to protect against one or both valves being open during an increase above RHR system design pressure. If the RHR system discharge line is used for an emergency core cooling system (ECCS) function, the power-operated valve is to be opened upon receipt of a safety injection signal once the reactor coolant pressure has decreased below the ECCS design pressure.

3. REVIEW GUIDELINES

The NRC guidelines used in this review are as follows:

(1) Identify the valves which isolate the RHR system from the reactor coolant pressure boundry. (Refer to NRC memorandum from B. L. Siegel, RSB, to P. A. Di Benedetto, SEP; which is enclosure 3 of a letter from Crutchfield NRC, SEPB, to Dittmore, LLNL, dated 6-10-80 [Ref. 3]).

(2) Evaluate the design features which provide protection against the overpressurization of the RHR system.

(3) Identify the related topic reviews in an appendix to this report.

(4) Compile a list of the major EI&C systems that are necessary for DBE and for safe shutdown of the plant. Submit the compilation of necessary items for safe shutdown as an appendix to NRC Safety Topic VII-3, entitled "Systems Required for Safe Shutdown."

(5) If power is locked-out to the RHR isolation MOVs, review to determine if any functions of the interlocks or permissives are adversely affected. (The report on NRC Safety Topic VI-7.C, among others, states which values have power locked out).

4. SYSTEM DESCRIPTION

The RHR loop consists of two pumps, two heat exchangers, and the necessary valves, piping, and instrumentation. During plant cooldown, coolant flows from the RCS to the RHR pumps, through the tube side of the RHR heat exchangers and back to the RCS. The single inlet line to the RHR loop commences at the hot leg of reactor coolant loop A, through two redundant pumps and their associated heat exchangers, and back to the cold leg of reactor coolant loop B via a single header.

The RHR pumps and heat exchangers serve dual functions. Although the normal duty of the RHR pumps and heat exchangers is performed during periods of reactor shutdown, this equipment is aligned during the injection phase after a loss-of-coolant-accident (LOCA) to perform the low-head safety injection (LPSI) function. In addition, during the recirculation phase of a LOCA the capability may be divided between the core-cooling function and the containment-cooling function as a part of the containment spray system.

5. EVALUATION AND CONCLUSIONS

The suction line of the RHR system is isolated from the loop A hot leg of the RCS by MOV-700 and MOV-701 in series. The discharge line of the RHR system is isolated from the loop B cold leg of the RCS by MOV-720 and MOV-721 in series. [Ref. 4, drawing 33013-436-A].

All permissive interlocks associated with the RHR system isolation MOVs are designed to open the valves; there are no permissive interlocks associated with isolation MOV closure.

Section 4.1 of the SEP review of Safe Shutdown Systems [Ref. 5] states that the permissive interlocks required to open the four RHR system isolation valves are as listed below:

MOV-700....RCS pressure must be less than 410 psig.
RHR suction valves MOV-850A and MOV-850B from the containment sump must be closed.

MOV-701....The valve is operated by a key switch.
RHR suction valves MOV-850A and MOV-850B from the containment sump must be closed.

MOV-720....No interlocks exist; valve operated by key switch.

MOV-721....RCS pressure must be less than 410 psig.

The RHR system discharge line is not used for an ECCS function that would require MOV-720 or MOV-721 to open; however, a branch of the RHR discharge line provides low pressure safety injection (LPSI) to the reactor vessel via parallel lines. Isolation between the RHR system and LPSI injection into the reactor vessel is provided by two separate paths from the RHR discharge line, with each path containing an MOV and check valve. MOV-852A and check valve 853A provide isolation in one path, while MOV-852B and check valve 8538 provide isolation in the other path [Ref. 4, drawing

33013-436-A; Ref. 6, drawing 33013-432-A]. The LPSI isolation MOVs open on a SI signal regardless of RCS pressure; there are no interlocks associated with closure of the LPSI isolation MOVs, although key switch closure capability is provided.

Section 4.1 of the SEP review of Safe Shutdown System [Ref. 5] states in part that:

> A branch of the RHR discharge line provides low pressure safety injection (LPSI) to the reactor vessel via parallel lines with one normally closed motor-operated valve (MOV) and one check valve in each line. The MOV position indication is provided in the control room and these valves receive an open signal coincident with the safety injection (SI) signal. The MOVs in the LPSI lines open on an SI signal before RCS pressure drops below RHR design pressure.

The plant complies to all EI&C aspects of the "RHR Interlock Requirements" review criteria listed in Section 2 of this report except for the following:

(1) The plant RHR system does not satisfy BTP ICSB 3 [Ref. 1] and BTP RSB 5-1 [Ref. 2] because the RHR discharge and suction isolation MOVs do not have independent diverse interlocks to prevent opening the valves until RCS pressure is below 410 psig. Only the inboard valves MOV-700 and MOV-721 have this interlock. The outboard valves MOV-701 and MOV-720 are manually controlled with key-locked switches. By procedure, MOV-701 and MOV-720 are not opened until RCS pressure is less than 410 psig.

(2) The plant RHR system does not satisfy BTP ICSB 3 [Ref. 1] and BTP RSB 5-1 [Ref. 2] because all RHR isolation MOVs lack an interlock feature to close them when RCS pressure increases above the RHR design pressure.

(3) The plant RHR system does not satisfy BTP ICSB 3 [Ref. 1] and BTP RSB 5-1 [Ref. 2] because the isolation MOVs in the LPSI lines (MOV-852A and MOV-852B) open on an SI signal before RCS pressure drops below RHR design pressure.

6. SUMMARY

The plant RHR interlock system fails to satisfy current licensing criteria for the following reasons:

(1) The RHR suction and discharge isolation MOVs do not have independent diverse interlocks to prevent opening the isolation MOVs until RCS pressure is below 410 psig.

(2) All RHR isolation MOVs lack an interlock feature to close them when RCS pressure increases above RHR design pressure.

(3) The isolation MOVs in the LPSI lines open on an SI signal regardless of RCS pressure.

The resolution of items 1, 2 and 3 are presented in Sections 3.1 and 3.2 of SEP Topic V-11.A.

REFERENCES

1. U.S. Nuclear Regulatory Commission, Branch Technical Position ICSB 3, "Isolation of Low Pressure Systems from the High Pressure Reactor Coolant System."

2. U.S. Nuclear Regulatory Commission, Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System."

3. NRC (D. M. Crutchfield) letter to LLNL (M. H. Dittmore), dated June 10, 1980.

4. Ginna drawing, 33013-436-A, "Auxiliary Coolant System".

5. SEP Review of Safe Shutdown Systems for the R.E. Ginna Nuclear Power Plant, Revision 1, undated.

6. Ginna drawing, 33013-432-A, "Safety Injection System."

APPENDIX A
NRC SAFETY TOPICS RELATED TO THIS REPORT

1. III-1, "Classification of Structures, Systems and Components."
2. III-10.A "Thermal Overload of MOVs."
3. V-10-.B, "RHR System Reliability."
4. V-11.A, "Requirements for Isolation of High and Low Pressure Systems."
5. V1-7.C "ECCS Single Failure Criterion and Requirements for Locking Out Power to Valves Including Independence of Interlocks on ECCS Valves."
6. VIII-3, "Systems Required for Safe Shutdown."
7. XVI, "Technical Specifications".

TOPIC V-12.A

SEE TOPIC II-4.E

TOPIC V-13

SEE TOPIC II-2.B

ATTACHMENT

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JOHN E. MAIER
VICE PRESIDENT

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June 23, 1981

Director of Nuclear Reactor Regulation
Attention: Mr. Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: SEP Topics V-10.B, V-11.A, V-11.B, VI-7.C.1, VII-3, and VIII-2, R.E. Ginna Nuclear Power Plant
Docket No. 50-244

References:

(1) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics, V-10.B, V-11.B, and VII-3 (Safe Shutdown Systems Report), May 13, 1981.

(2) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics V-11.A, V-11.B, and VI-7.C.1, dated April 24, 1981.

(3) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics VII-3 and VIII-2, dated April 2, 1981.

Dear Mr. Crutchfield:

This letter is in response to the SEP topic assessments provided in the three above-referenced letters. Due to the intimate relationship of the "Safe Shutdown" topics V-10.B, V-11.A, V-11.B and VII-3 addressed in these three letters, all of our comments are provided concurrently in the three attached responses. This should aid the inclusion of our comments into the NRC's "SEP Integrated Assessment".

Very truly yours,

John E. Maier

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Attachments

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Attachment 1: RG&E responses to NRC Assessment of SEP Topics V-10.B, RHR System Reliability, V-11.B, RHR Interlock Requirements, and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems report), May 13, 1981.

1. In RG&E's January 13, 1981 response to the NRC's November 14, 1980 "Safe Shutdown Systems" assessment, a number of comments were made which have not been incorporated into Revision 2 of this assessment, transmitted by letter dated May 13, 1981. We feel these comments were valid, and should be incorporated. For continuity, these comments will be listed below (with their original comment numbers):

"1. On page 5, Piping System Passive Failures, the NRC assumes piping system passive failures"...beyond those normally postulated by the staff, e.g., the catastrophic failure of moderate energy systems...". Although it is shown that safe shutdown following such an event could be achieved, it is not considered that such an evaluation should even be made. As noted by the staff, it is clearly beyond a reasonable design basis. It is thus recommended that this paragraph be deleted from the evaluation. Subsequent evaluations to this "criterion", such as those related to the CCW system on page 22 and 23, should also be deleted.

11. In paragraph g on page 66, it is noted that, when applying the power diversity requirements of BTP ASB 10-1 in event of an SSE, no means to supply feed to the steam generators exists. It was determined that this was acceptable, based on low likelihood of occurrence.

This conclusion is correct; however, since BPT ASB 10-1 does not consider an SSE in conjunction with the loss of all A.C. power, there is no need to even make the evaluation. The comparisons in the SEP program should be to current criteria, rather than to arguable extrapolations. Reference to loss of all A.C. power in conjuncton with an SSE should thus be deleted from this paragraph.

12. On page A-4, it is noted that additional systems are required to achieve cold shutdown for a PWR than for a BWR because of a difference in the definition of cold shutdown. This does not appear to be a reasonable basis. System requirements should be based on specific safety reasons. The NRC should be consistent in its requirements for cold shutdown, or provide a technical basis for any differences."

2. Staff position 1 states that "the licensee must develop plant operating/emergency procedures for conducting a plant shutdown and cooldown using only the systems and equipment identified in Section 3.1 of the SEP Safe Shutdown Systems Report." RG&E disagrees with the need for these procedures. We reiterate the comments provided in our January 13, 1981 response that the operator should perform a cooldown with the best equipment available to him at the time. If a piece of non-safety equipment is available, and would be the most beneficial for performing a required function, it is expected that this piece of equipment would be used. If it is not available, the operator could fall back on the use of safety-grade equipment. But RG&E does not intend to commit plant personnel to use only safety-related equipment, if non-safety equipment is available and more effective. We feel that it would be impossible to determine when a "safety-grade-only" cooldown procedure would ever be implemented. As long as the safety-grade equipment is available (and the safe shutdown assessment concudes that it is), RG&E considers that the necessary safety requirements are met.

   RG&E also notes that no regulatory basis for this requirement is provided. It is admitted in Section 4.5 of the Safe Shutdown report that "the need for procedures for these evaluations is <u>not</u> identified in Regulatory Guide 1.33...". Section 4.5 then goes on to say that the basis is found in BTP RSB 5-1 and SEP Topic VII-3. But BTP RSB 5-1 merely references RG 1.33, and this <u>is</u> the assessment of SEP Topic VII-3.

   Therefore, since no basis for this "requirement" exists, and we do not feel that it would even be beneficial, and since the Safe Shutdown report did conclude that the capability for attaining cold shutdown using only safety-related equipment exists, RG&E concludes that this staff position should be deleted from consideration.

3. Staff position 3 does not appear to take into account the information provided in our March 27, 1981 submittal regarding SEP Topic V-11.A. Enclosure 3 to that submittal provides the valve equipment specification, noting that the 700, 701, 720 and 721 MOV's are designed such that they physically are unable to open against a differential pressure of greater than 500 psi. This ensures that an intersystem LOCA caused by the opening of the outboard valves, plus leakage of the inboard valves, cannot occur, since the outboard valves cannot open.

Even without this provision, it is difficult to comprehend how the Ginna arrangement could result in an "Event V". By administrative procedure, the RHR valves are key-locked closed, with power removed. Further, interlocks are provided for the inboard RHR valves. Thus, for an "Event V" to occur would require the:

1) failure of the administrative procedure requiring power lock-out (at the breaker),

2) failure of the administrative procedure governing operation of the valve at power,

3) failure of the inboard isolation valve,

4) failure of the relief valve (RV 203) which has a capacity of 70,000 lb/hr at its 600 psig setpoint, to relieve the leakage past the inboard RHR valve.

This set of failures is considered very remote. When coupled with the fact that the RHR valve design prevents opening of the valves against a greater than 500 psi differential pressure, it is RG&E's conclusion that the possibility of an intersystem LOCA should not be a credible design basis. No additional modifications, such as diverse interlocks for the outboard valves, are warranted.

4. Staff position 5 states that "the operating procedures for the Ginna plant should be modified to direct the operator to cooldown and depressurize to RHR initiation parameters within 36 hours whenever the Service Water System is used for steam generator feedwater..." This position is based on the reference BNL-NUREG-28147, "Impure Water in Steam Generators and Isolation Condensers." We have had this report reviewed by NWT Corporation. NWT-167, "Use of Lake Ontario Water in Steam Generator During Hot Shutdown" (attached) concludes that, "although not recommended from the standpoint of maximizing component life, and operation for periods up to several days is not expected to result in any significant cracking or in deterioration of steam generator integrity."

RG&E therefore concludes that a specific directive to cool down and depressurize to RHR initiation conditions is not warranted, and should not be included in a procedure. The capability to do this does exist, however, and could be used if determined to be necessary at the time.

Attachment 2: RG&E responses to NRC letter of April 24, 1981 regarding SEP Topics V-11.A, "Isolation of High and Low Pressure Systems", V-11.B, "RHR Interlock Requirements", and VI-7.C.1, "Independence of Redundant Onsite Power Systems".

1. The Safety Evaluation for SEP Topic V-11.A, "Requirements for Isolation of High and Low Pressure Systems", specifies that the outboard RHR valves should have diverse interlocks to prevent opening when the RCS pressure is greater than RHR system design pressure.

   RG&E rationale for not providing these additional interlocks is provided in comment 3 of Attachment 1 of this transmittal.

2. The safety evaluation also required that interlocks be installed on the CVCS suction valves (200A, 200B, 202), to prevent a possible overpressurization of the CVCS letdown line outside containment. RG&E has noted in our March 27, 1981 letter on this SEP Topic that a relief valve (RV 203), with a capacity greater than the combined capacity of the three orifices, would relieve the pressure buildup caused by closure of the containment isolation valve 371. No overpressurization of the CVCS would thus be expected.

   RG&E has also evaluated the potential consequences of such an overpressurization event, with a subsequent small LOCA outside containment, and determined that no unacceptable consequences would result. This break would be a small LOCA outside containment (maximum flow of 140 gpm), and would be terminated by closure of valves 200A, 200B, and 202 either by operator action or automatically by low pressurizer level. Radiological consequences would be minimal, since no fuel damage would result. This event is specifically evaluated by SEP Topic XV-16, "Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment." RG&E has provided information concerning this topic by letter dated June 18, 1980 from L. D. White Jr. to Mr. Dennis M. Crutchfield.

   The RG&E conclusion is that, based on the availability of RV 203 to prevent overpressurization, together with the lack of unacceptable consequences due to an overpressurization, no interlocks or other modifications are required for the CVCS suction valves.

3. The safety evaluation further states that position indication is required on the CVCS discharge check valves. As stated in our March 27, 1981 letter on SEP Topic V-11.A, we do not believe that this line should be classified as a low pressure

system connected to the RCS, since the piping is 2500-lb piping throughout its length (to the positive displacement charging pump). RG&E has had no experience with failures of the positive displacement charging pump pistons to hold primary system pressure, nor would any failures be anticipated. Our contention that the charging line is not a line of concern is borne out by a memo from Edson G. Case to Raymond F. Fraley, "Isolation of Low Pressure Systems from Reactor Coolant System", dated July 11, 1977. That letter transmitted an NRC study of this subject to the ACRS, and evaluated all potential lines of concern. The charging line was not included.

To verify that the charging line was not a valid "Event V" concern, RG&E calculated the PWR Check Valve Event Tree (Section 4.4 of WASH-1400), using the charging line configuration (two in-series check valves and a charging pump piston). Very conservatively assuming that both check valves were undetected open, and that the probability of the charging pump piston failure was equal to a check valve failure, the $\overline{Q_{SUM}}$ calculated for this configuration was determined to be 1.4×10^{-8}/year. This is a low enough value to obviously be of no concern.

RG&E therefore considers that check valve position indication is not needed on the charging line check valves.

4. With respect to the SEP Topic Assessment V-11.B, no comments are necessary, since the resolution of outstanding issues is addressed in the topic assessment for SEP Topic V-11.A.

5. The additional information requested for SEP Topic VI-7.C.1 is presently being developed. It is anticipated that this information can be furnished to the NRC by July 15, 1981.

Attachment 3: RG&E responses to NRC letter of April 2, 1981, concerning SEP Topics VII-3, "Electrical, Instrumentation, and Control Feature of Systems Required for Safe Shutdown", and VIII-2, "Diesel Generators".

It appears that all comments provided by RG&E in our January 23, 1981 and January 30, 1981 letters concerning these topics have been properly incorporated.

Based on the resolution of all open items, and the removal of diesel generator testing from SEP Topic VIII-2, RG&E concludes that both of these topics are complete, with no outstanding issues to be carried into the Integrated Assessment.

NWT 167
February 1981

USE OF LAKE ONTARIO WATER IN STEAM GENERATORS DURING HOT SHUTDOWN

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INTRODUCTION

The possibility of using Lake Ontario water as an emergency PWR feedwater supply for more than 36 hours during which the plant would be brought to cold shutdown is being considered. The maximum steaming rate during such a period would be 100,000 pounds/h (200 gpm) at a temperature of 350°F. As a consequence of steaming, impurities of the untreated Lake Ontario water will concentrate in the steam generator. Of major concern is the possible risk of stress corrosion cracking (SCC) of steam generator materials in contact with the concentrated solution thus formed. To address this concern, the chemistry variation in the liquid phase as steaming proceeds at 350°F was estimated with emphasis on pH. Then, the possible potential for SCC was assessed on the basis of these estimates and available SCC data.

pH VARIATION AT 350°F UPON STEAMING LAKE ONTARIO WATER

A. Computer Modeling

The composition of Lake Ontario water as determined by RGE is given in Table 1.[1]

TABLE 1
LAKE ONTARIO WATER ANALYSIS
ppm

Calcium	35	Nitrate	2.5
Magnesium	8	Phosphate	0.3
Sodium	13	Fluoride	0.15
Potassium	3.6	Silica (as SiO_2)	0.25
Aluminum	0.1	Dissolved Oxygen	9.5
Chloride	32	Ammonia (as Nitrogen)	0.24
Sulfate	35		

Estimates of the water chemistry variation upon steaming were developed using the following assumptions:

1. Since aluminum and silica are in stoichiometric proportion in Lake Ontario water (Table 1), they are assumed to precipitate as aluminum silicate (clay) upon concentrating and therefore are removed from solution.

2. Since calcium occurs in the water (Table 1) in large excess over phosphate, it is assumed to precipitate all the phosphate as calcium hydroxy apatite ($Ca_5(PO_4)_3OH$) and remove it from the solution. The calcium in solution is decreased by the corresponding amount.

3. Fluoride and nitrite are assumed to behave as chloride. Potassium is assumed to behave as sodium.

4. Sodium and chloride in solution are assumed to remain completely dissociated.

5. Calcium carbonate precipitation is neglected. Degasification of CO_2 by steaming is assumed to occur.

6. The concentration of sodium and calcium chlorides is assumed limited by a solubility of 5 molal.

7. Chemical equilibrium expressions of references 2 and 3 apply.

On this basis, the liquid solution pH variation upon steaming at 350°F was estimated as a function of concentration factor defined as the mass ratio of total water (steam + liquid) to liquid water residual. The results are presented graphically in Figure 1. It is important to note that the definition of pH used here is that followed by Mesmer[4] in the determination of the dissociation constant of water at high temperatures, viz, the negative of the logarithm of the hydrogen ion concentration (not of its activity). Similarly, neutral pH is defined as that where the hydrogen and hydroxyl ion concentrations are equal. This neutral pH is a function of ionic strength. Therefore, the pH variation of the concentrated solutions must be considered in relation to that of neutral pH, also plotted in Figure 1. For basic solutions as is the case considered here, it is important to bear in mind that the hydroxyl ion concentration is expressed in terms of pH as follows:

$$C_{OH^-} = 10^{pH-2NpH}$$

(where NpH is the neutral pH value) and that when the neutral pH varies together with the ionic strength as the liquid solution is being concentrated upon steaming, the basicity of the solution may not be appreciated from the solution pH alone. The equivalent NaOH concentration is more suitable for this purpose and is plotted also in Figure 1.

B. Discussion

Steam Generator Bulk Water

Based on a maximum feed rate of 200 gpm to the steam generator and a total steam generator liquid volume of approximately 12,000 gallons, a maximum of one steam generator volume is steamed away each hour. Therefore, under maximum steaming conditions, the concentration factor achieved in the bulk steam generator water is t + 1 where t is the number of hours of steaming.

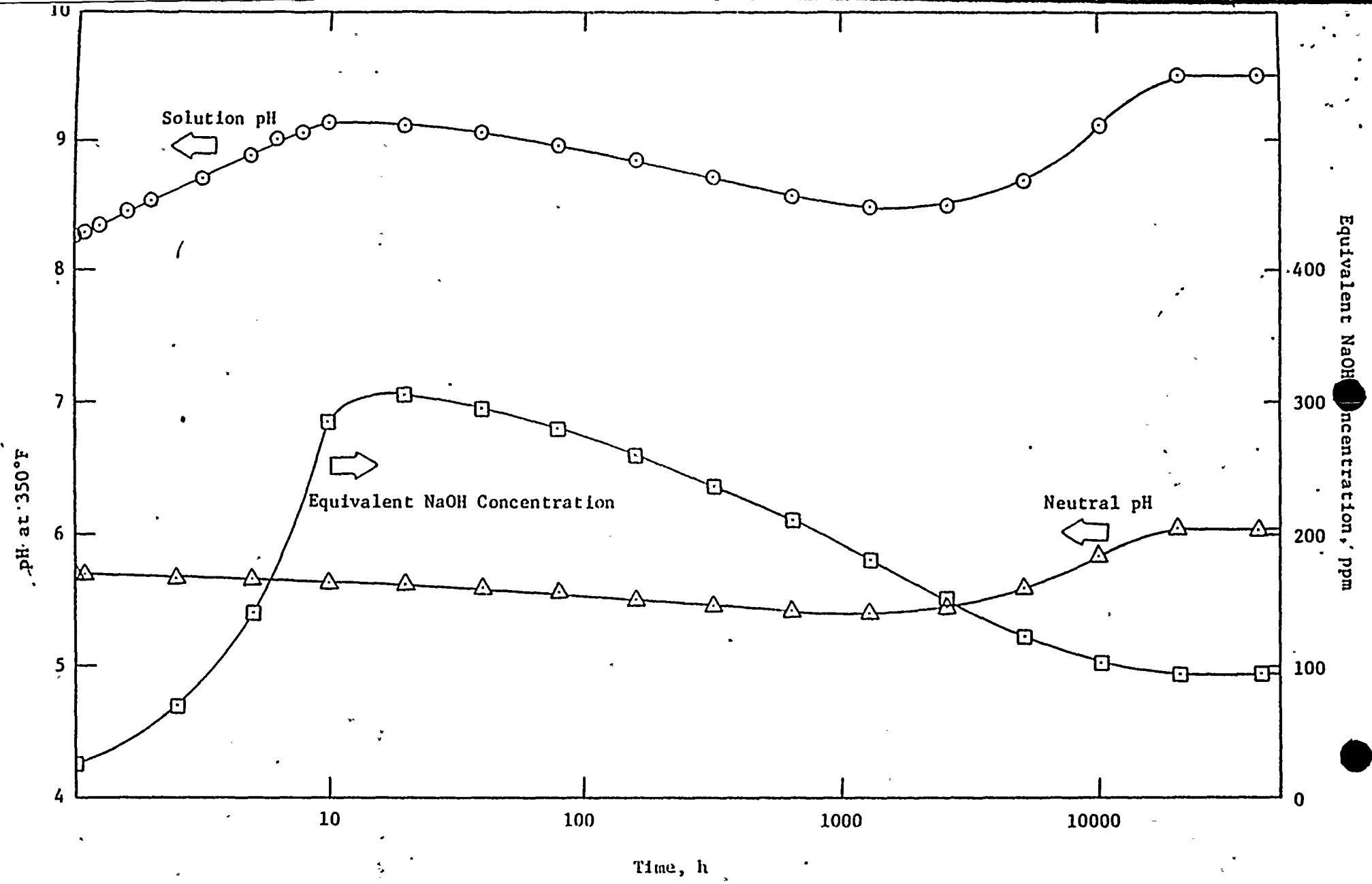

Figure 1. Variation of Steam Generator pH with Steaming at 350°F (feeding Lake Ontario water at 200 gpm)

The variation with time of the equivalent sodium hydroxide concentration in the steam generator with steaming of emergency Lake Ontario feedwater then can be followed on Figure 1. It is seen that a maximum equivalent NaOH concentration of about 300 ppm will be reached in the steam generator bulk water when 15 to 20 steam generator volumes will have been converted to steam, i.e., in approximately twenty hours. Further boiling should then decrease the equivalent NaOH concentration as magnesium and/or calcium hydroxides and/or calcium sulfate precipitate with increased concentrating. The decrease reaches a limit (at about 20,000 steam generator volumes converted to steam, i.e., in 20,000 hours) when sodium and calcium chlorides start to precipitate also. This limit is estimated at about 100 ppm equivalent NaOH for Lake Ontario water composition as specified in Table 1 and with the assumptions already stated. The assumptions seem reasonable and, at any rate, can be tested experimentally with a small autoclave from which known amounts of Lake Ontario water would be boiled away at 350°F at constant liquid level in the autoclave.

Crevices

The estimated equivalent NaOH solution concentration in steam generator crevices will depend upon the relative degree of crevice solution concentration above the bulk water. In tube to tube support plate crevices, there may be a distribution of relative concentration factors of unity and higher.

The chemistry in a crevice would lead that of the bulk in the sense that the chemistry of a specific crevice would travel the same curve (Figure 1) as the bulk but would be at a point on the curve somewhat ahead of the bulk. Since the causticity of Lake Ontario water is not a strong function of concentration, this does not pose a problem. Indeed it is expected in this case that after a short period of steaming, the crevice chemistry will be less basic than that of the bulk.

Cooling Water Composition

The NWT chemistry modeling work discussed herein is based on the chemical composition of Lake Ontario water summarized in Table 1 as supplied by RGE.

It is possible that seasonal changes in the characteristics of the lake water may result from the interrelation between source river flowrates, industrial pollution and/or acid rain. NWT has no relevant data to assess such effects.

It may be desirable that analyses made of Lake Ontario water during different seasons and under various conditions be fed into the NWT chemistry model. In this manner the safety of feeding Lake Ontario water, over the range of likely chemical compositions, can be verified.

POTENTIAL FOR SCC

A. Corrosion

The most aggressive solution expected based on the modeling work is 300 ppm NaOH, with ≤10 ppm O_2 (see below) at 350°F. Although laboratory data regarding these exact conditions are not available, data are available which can be extrapolated to assess the maximum corrosion rates expected for a given range of conditions.

van Rooyen and Kendig[5] cite Westinghouse data indicating that U-bends of Alloy 600 in deaerated 10% NaOH crack after several months of exposure. Figures 2 and 3 summarize Westinghouse tests[6] which show that at least 100 days of exposure to deaerated 10% NaOH at 600°F is required to produce a detectable crack in stressed Alloy 600.

Figure 4 shows data gathered by Berge and Donati.[7] These curves are for yield stressed C rings at 660°F. Extrapolating the curve for mill annealed Alloy 600 to 300 ppm NaOH yields a minimum time of 3500-4000 hours to induce a 0.5 millimeter crack.

The data presented above are for deaerated systems and are consistent with van Rooyen's[5] conclusion that Alloy 600 in 10% NaOH would not crack for several months. In the presence of oxygen, the susceptibility of Alloy 600 to SCC may be increased. Figure 5 shows stress corrosion behavior in 600°F high purity water containing varying amounts of oxygen in the gas phase above the water and adjusted to pH 10 at startup with ammonia.[8] As the oxygen content of the gas phase increased, the percent of the specimens attacked and extent of the attack increased. As noted in Figure 5 the average life in the 18-week test varied from no cracking with 1% oxygen in the gas phase (≤2 ppm oxygen in the water) to 7 weeks with 100% oxygen in the gas phase (≤200 ppm oxygen in the water).

McIlree and Michels[9] and later Sedriks, et al.,[10] reported less than 20% cracking after 27 days for Alloy 600 (2 common heat treatments) in aerated, 50% NaOH at 570°F.

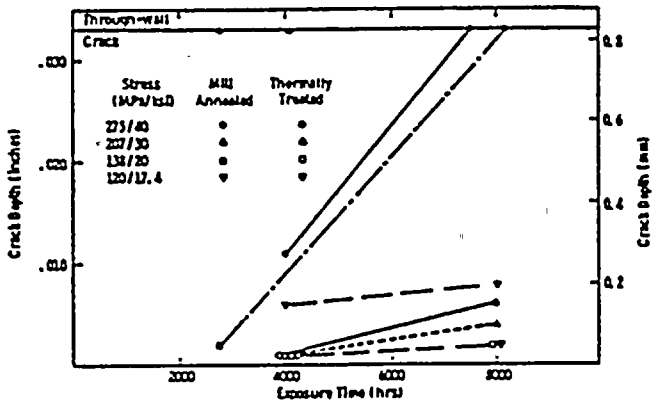

Figure 2. Crack Depth as a Function of Time, Stress Level and Material Condition for ID Pressurized Capsules Exposed to Deaerated 10% NaOH at 600°F[6]

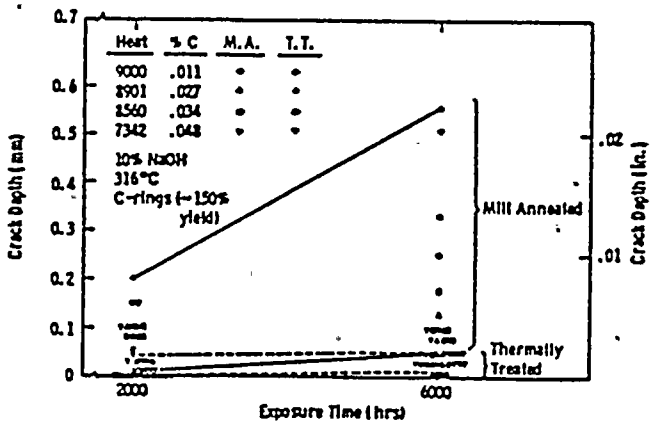

Figure 3. Crack Depth as a Function of Exposure Time for Mill Annealed and Thermally Treated Inconel Alloy 600 Exposed to Deaerated 10% NaOH at 600°F[6]

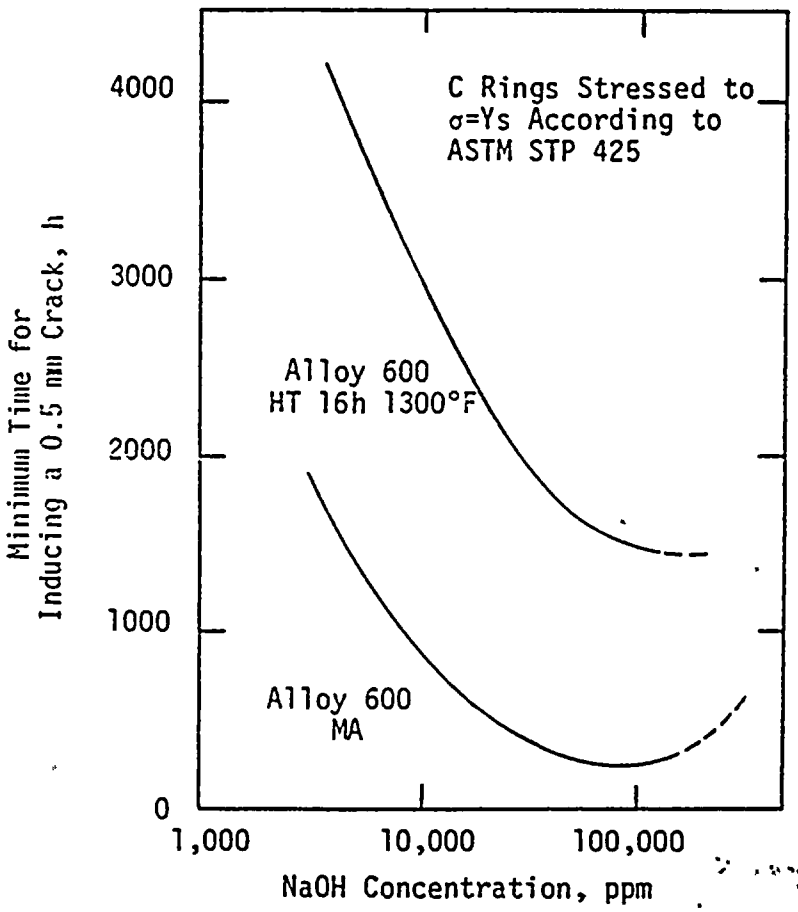

Figure 4. Resistance to Stress Corrosion Cracking of Alloy 600 Mill-Annealed or Heat Treated at 1300°F as a Function of Deaerated Sodium Hydroxide Concentration at 600°F[7]

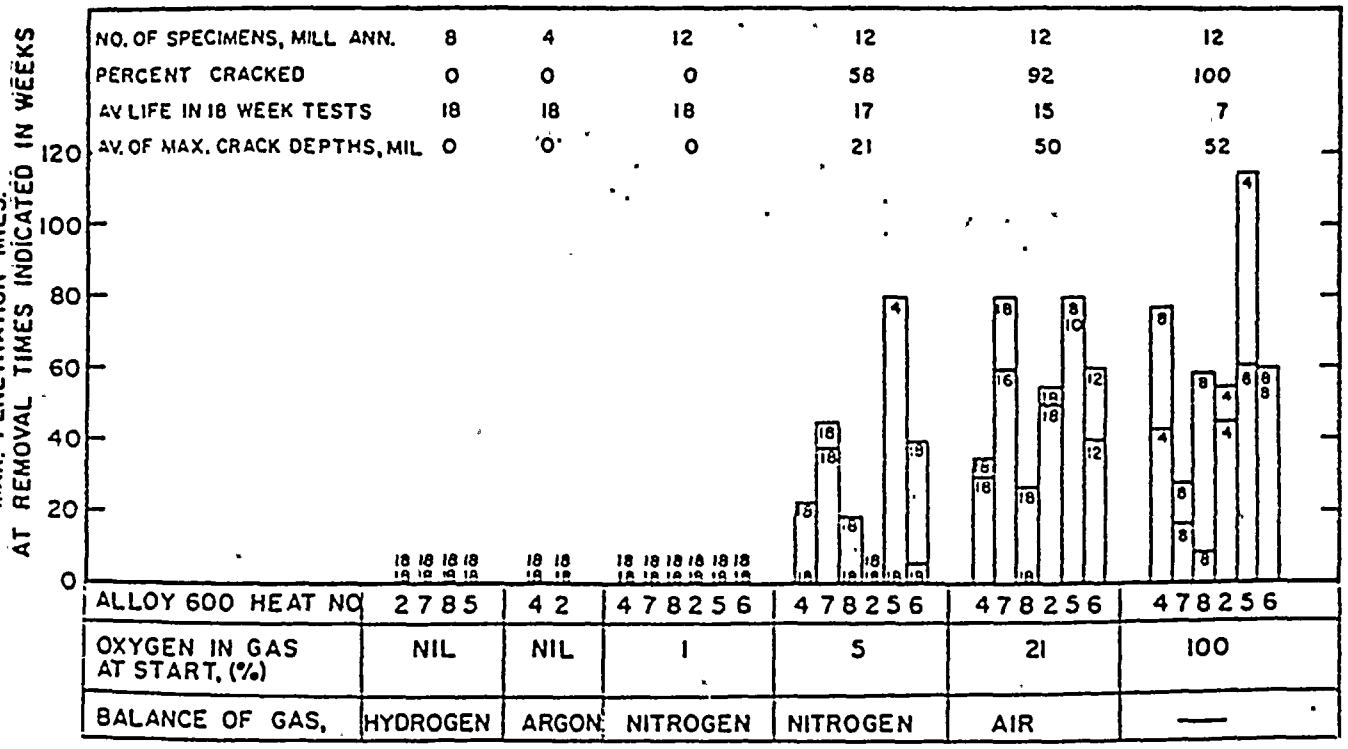

Figure 5. Stress Corrosion Behavior in Crevice Areas in Mill Annealed Inconel 600 Double U-bend Specimens in 600°F High Purity Water Adjusted to pH 10 with Ammonia at Startup[8]

Laboratory studies show that there is a significant temperature dependence of caustic stress corrosion cracking as illustrated in Figures 6 and 7. These results are for pressurized capsules exposed to 10% and 50% NaOH at varying stresses at temperatures ranging from 650 to 550°F. As can be seen, reducing the temperature below 600°F significantly extends the time for SCC to occur. This temperature dependence is further illustrated in Figure 8 where temperature is plotted versus rate constant for both 10% and 50% NaOH.

B. Oxygen

The lake water fed to the generators probably would be air saturated (approximately 10 ppm O_2). However, at 350°F the K_D (the equilibrium ratio between steam phase and liquid phase) for oxygen is slightly greater than 5000. Even though the dynamic distribution in practice may not reach true equilibrium conditions, the net effect of the high K_D value is that recriculated steam generator coolant will contain oxygen concentrations lower than 10 ppm. This recirculated coolant will dilute the oxygen concentration of incoming feedwater with a net oxygen level in the downcomer of ~1 to 10 ppm, depending on the recirculation ratio under the contingency conditions.

C. Conclusion

With the significantly lower concentrations of sodium hydroxide (max 300 ppm), oxygen concentration ≤10 ppm and the lower temperature (350°F) involved, the contingency of feeding Lake Ontario water to the Ginna steam generators should result in no measureable damage to steam generator internals. Although not recommended from the standpoint of maximizing component life, such operation for periods up to several days is not expected to result in any significant cracking or in a deterioration of steam generator integrity.

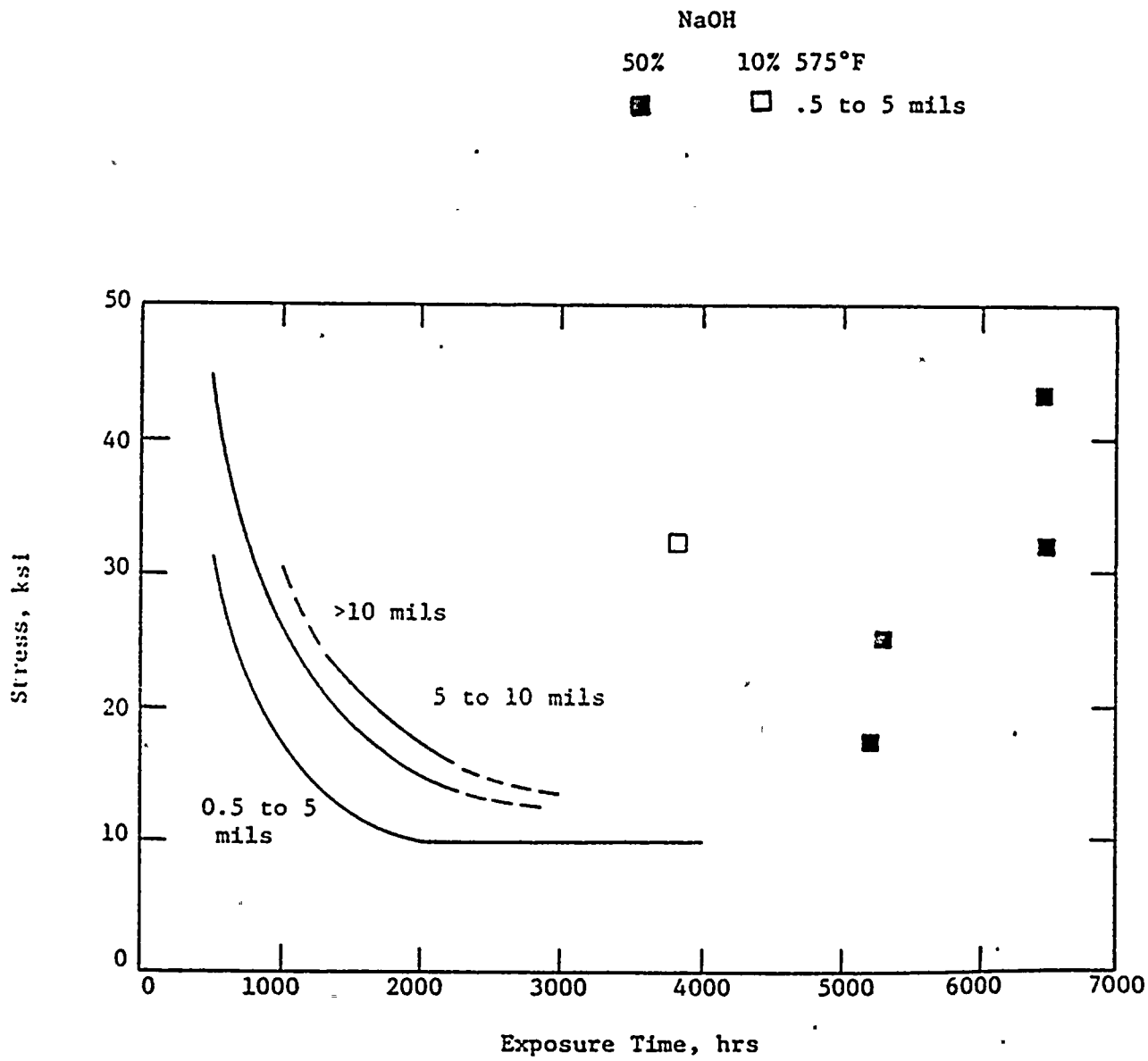

Figure 6. Caustic Cracking of Mill Annealed Alloy 600 at 575°F
(Lines depict zones of crack depth from 10% NaOH at 600°F)

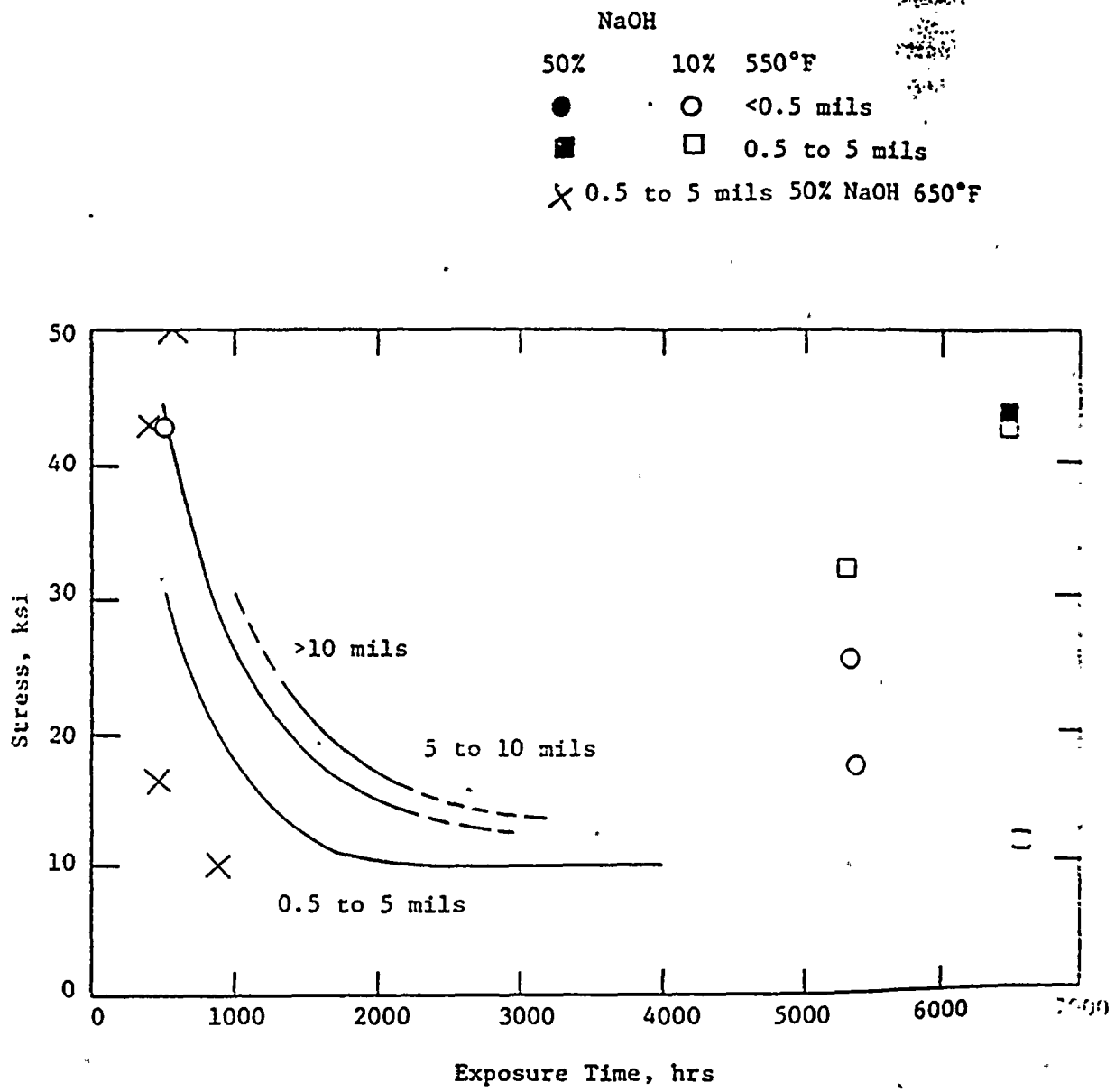

Figure 7. Caustic Cracking of Mill Annealed Alloy 600 at 550°F and 650°F (Lines depict zones of crack depth from 10% NaOH at 600°F)

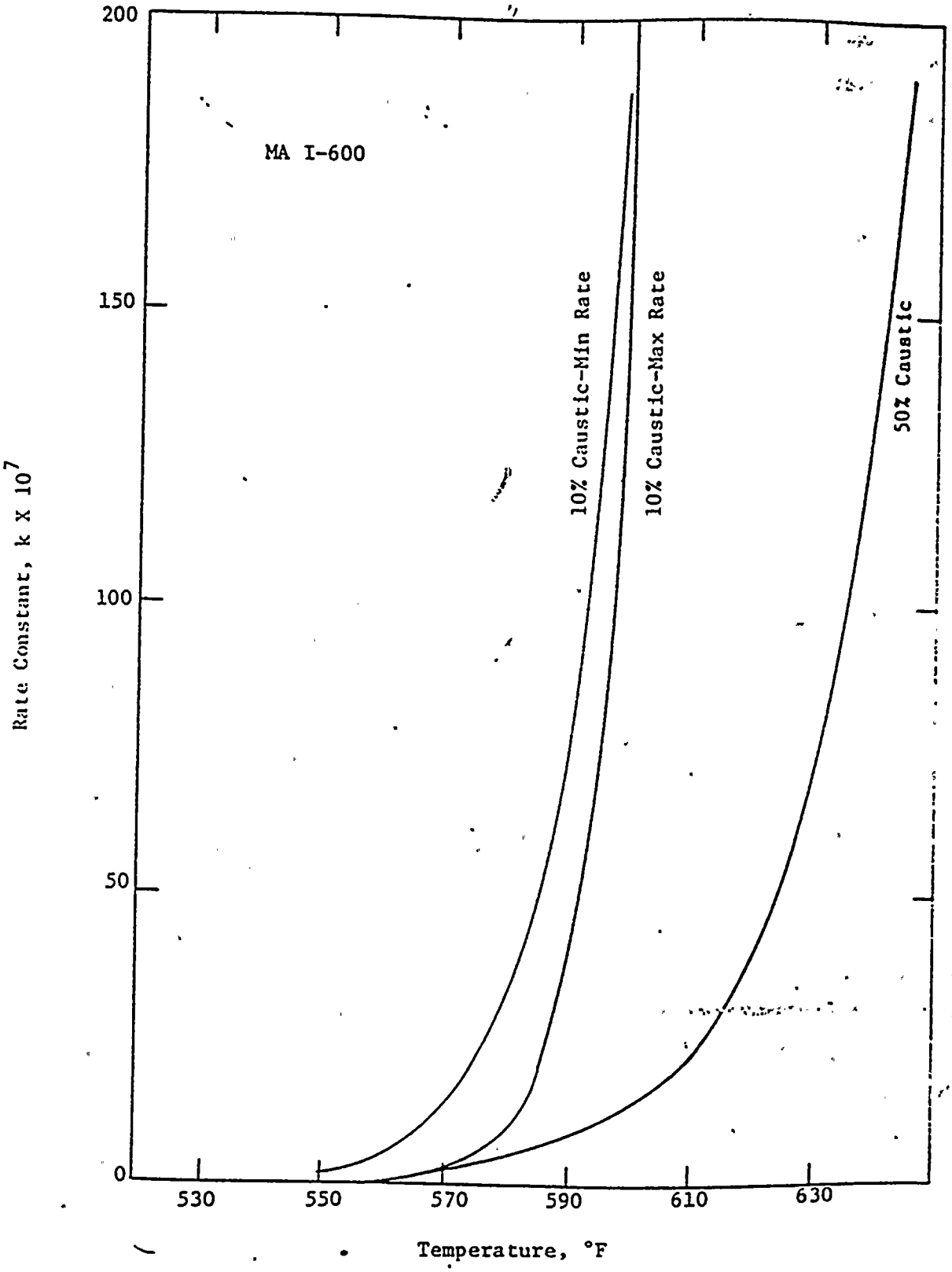

Figure 8. Indicated Variation in Rate of SCC with Temperature

COMMENTS ON VAN ROOYEN AND KENDIG'S REPORT[5]

The referenced report[5] basically is a broad summary covering a large volume of data applicable in part to stainless steels and in part to Alloy 600. We are generally in agreement with their nine summary conclusions, but find it difficult to apply their broad-brush treatment to the specifics of a PWR hot shutdown with lake water added to the steam generators at 350°F. Their document is misleading for such an application in two respects:

1. Caustic Concentration

Their statement that ..."For the purposes of SCC predictions, it has to be assumed that the time to form dangerous levels of NaOH, once impurities have been introduced, is short, i.e., one day or less" does not fully recognize the specific concentration chemistry of the cooling water involved nor the low heat flux available and the cutback in steaming rate during a period of hot shutdown. In the case of the Lake Ontario water, for example, the maximum NaOH concentration reached is 300 ppm (after steaming ~20 steam generator volumes) with a decrease in concentration thereafter.

2. Temperature

All of the test work referenced in the referenced report[5] was performed in the temperature range of 550 to 630°F. With the significant temperature dependence of caustic SCC as shown above, the concern at 350°F is many times less than is indicated from the data quoted by the authors.[5]

Based on the above three considerations, it is our assessment that the generalized time limit of 36 hours in the report[5] is not directly applicable to the Ginna steam generators steaming at 350°F while fed by Lake Ontario water.

REFERENCES

1. Harhay, A., Rochester Gas & Electric, Personal Communication, February 11, 1981.

2. Leibovitz, J., and Sawochka, S. G., "Modeling the Effects of Condenser Inleakage on PWR Chemistry", presented at 41st Annual International Water Conference, Pittsburgh, Pennsylvania, October 1980.

3. Leibovitz, J. and Sawochka, S. G., "Modeling of Cooling Water Inleakage Effects in PWR Steam Generators, Topical Report, Research Project 404-1", Electric Power Research Institute, May 1980, to be published.

4. Mesmer, R. E., Baes, C. F., Jr., and Sweeton, F. M., "Boric Acid Equilibria and pH in PWR Coolants", Proceedings of the 32nd International Water Conference, Pittsburgh, Pennsylvania, November 1971, pp. 55-65.

5. van Rooyen, D., and Kendig, M. W., "Impure Water in Steam Generators and Isolation Generators", Brookhaven National Laboratory, June 1980 (Draft-BNL-NUREG-28147).

6. Airey, G. P., "Effect of Processing Variables on the Caustic Stress Corrosion Resistance of Inconel Alloy 600", presented at NACE Meeting, March 1979 (Paper Number 101).

7. Berge, Ph. and Donati, J. R., "Materials Requirements for Steam Generator Tubing", presented at International Conference on Materials Performance in Nuclear Steam Generators, St. Petersburg, Florida, October 1980.

8. Copson, H. R. and Economy, G., "Effect of Some Environmental Conditions on Stress Corrosion Behavior of Ni-Cr-Fe Alloys in Pressurized Water", Corrosion, 24, No. 3, pp. 55-65 (March 1968).

9. McIlree, A. R. and Michels, H. T., "Stress Corrosion Behavior of Fe-Cr-Ni and Other Alloys in High Temperature Caustic Solutions", Corrosion, 33, No. 2, pp. 60-67 (February 1977).

10. Sedriks, A. J., et al., "Inconel Alloy 690-A New Corrosion Resistant Material", Corrosion Engineering (Japan), 28, No. 2, pp. 82-95 (1979).

11. Burstein, S., WEPCO, ltr to H. R. Denton, NRC, dtd November 23, 1979, with attachments.

ATTACHMENT

ROCHESTER GAS AND ELECTRIC CORPORATION • 89 EAST AVENUE, ROCHESTER, N.Y. 14649

JOHN E. MAIER
VICE PRESIDENT

TELEPHONE
AREA CODE 716 546-2700

RECEIVED
JUN 29 1981
U.S. NUCLEAR REGULATORY COMMISSION

June 23, 1981

Director of Nuclear Reactor Regulation
Attention: Mr. Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: SEP Topics V-10.B, V-11.A, V-11.B, VI-7.C.1, VII-3, and VIII-2, R.E. Ginna Nuclear Power Plant Docket No. 50-244

References:

(1) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics, V-10.B, V-11.B, and VII-3 (Safe Shutdown Systems Report), May 13, 1981.

(2) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics V-11.A, V-11.B, and VI-7.C.1, dated April 24, 1981.

(3) Letter from Dennis M. Crutchfield, NRC, to John E. Maier, RGE, SEP Topics VII-3 and VIII-2, dated April 2, 1981.

Dear Mr. Crutchfield:

This letter is in response to the SEP topic assessments provided in the three above-referenced letters. Due to the intimate relationship of the "Safe Shutdown" topics V-10.B, V-11.A, V-11.B and VII-3 addressed in these three letters, all of our comments are provided concurrently in the three attached responses. This should aid the inclusion of our comments into the NRC's "SEP Integrated Assessment".

Very truly yours,

John E. Maier

John E. Maier

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Attachments

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Attachment 1: RG&E responses to NRC Assessment of SEP Topics V-10.B, RHR System Reliability, V-11.B, RHR Interlock Requirements, and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems report), May 13, 1981.

1. In RG&E's January 13, 1981 response to the NRC's November 14, 1980 "Safe Shutdown Systems" assessment, a number of comments were made which have not been incorporated into Revision 2 of this assessment, transmitted by letter dated May 13, 1981. We feel these comments were valid, and should be incorporated. For continuity, these comments will be listed below (with their original comment numbers):

"1. On page 5, Piping System Passive Failures, the NRC assumes piping system passive failures"...beyond those normally postulated by the staff, e.g., the catastrophic failure of moderate energy systems...". Although it is shown that safe shutdown following such an event could be achieved, it is not considered that such an evaluation should even be made. As noted by the staff, it is clearly beyond a reasonable design basis. It is thus recommended that this paragraph be deleted from the evaluation. Subsequent evaluations to this "criterion", such as those related to the CCW system on page 22 and 23, should also be deleted.

11. In paragraph g on page 66, it is noted that, when applying the power diversity requirements of BTP ASB 10-1 in event of an SSE, no means to supply feed to the steam generators exists. It was determined that this was acceptable, based on low likelihood of occurrence.

This conclusion is correct; however, since BPT ASB 10-1 does not consider an SSE in conjunction with the loss of all A.C. power, there is no need to even make the evaluation. The comparisons in the SEP program should be to current criteria, rather than to arguable extrapolations. Reference to loss of all A.C. power in conjuncton with an SSE should thus be deleted from this paragraph.

12. On page A-4, it is noted that additional systems are required to achieve cold shutdown for a PWR than for a BWR because of a difference in the definition of cold shutdown. This does not appear to be a reasonable basis. System requirements should be based on specific safety reasons. The NRC should be consistent in its requirements for cold shutdown, or provide a technical basis for any differences."

2. Staff position 1 states that "the licensee must develop plant operating/emergency procedures for conducting a plant shutdown and cooldown using only the systems and equipment identified in Section 3.1 of the SEP Safe Shutdown Systems Report." RG&E disagrees with the need for these procedures. We reiterate the comments provided in our January 13, 1981 response that the operator should perform a cooldown with the best equipment available to him at the time. If a piece of non-safety equipment is available, and would be the most beneficial for performing a required function, it is expected that this piece of equipment would be used. If it is not available, the operator could fall back on the use of safety-grade equipment. But RG&E does not intend to commit plant personnel to use only safety-related equipment, if non-safety equipment is available and more effective. We feel that it would be impossible to determine when a "safety-grade-only" cooldown procedure would ever be implemented. As long as the safety-grade equipment is available (and the safe shutdown assessment concudes that it is), RG&E considers that the necessary safety requirements are met.

   RG&E also notes that no regulatory basis for this requirement is provided. It is admitted in Section 4.5 of the Safe Shutdown report that "the need for procedures for these evaluations is <u>not</u> identified in Regulatory Guide 1.33...". Section 4.5 then goes on to say that the basis is found in BTP RSB 5-1 and SEP Topic VII-3. But BTP RSB 5-1 merely references RG 1.33, and this <u>is</u> the assessment of SEP Topic VII-3.

   Therefore, since no basis for this "requirement" exists, and we do not feel that it would even be beneficial, and since the Safe Shutdown report did conclude that the capability for attaining cold shutdown using only safety-related equipment exists, RG&E concludes that this staff position should be deleted from consideration.

3. Staff position 3 does not appear to take into account the information provided in our March 27, 1981 submittal regarding SEP Topic V-11.A. Enclosure 3 to that submittal provides the valve equipment specification, noting that the 700, 701, 720 and 721 MOV's are designed such that they physically are unable to open against a differential pressure of greater than 500 psi. This ensures that an intersystem LOCA caused by the opening of the outboard valves, plus leakage of the inboard valves, cannot occur, since the outboard valves cannot open.

Even without this provision, it is difficult to comprehend how the Ginna arrangement could result in an "Event V". By administrative procedure, the RHR valves are key-locked closed, with power removed. Further, interlocks are provided for the inboard RHR valves. Thus, for an "Event V" to occur would require the:

1) failure of the administrative procedure requiring power lock-out (at the breaker),

2) failure of the administrative procedure governing operation of the valve at power,

3) failure of the inboard isolation valve,

4) failure of the relief valve (RV 203) which has a capacity of 70,000 lb/hr at its 600 psig setpoint, to relieve the leakage past the inboard RHR valve.

This set of failures is considered very remote. When coupled with the fact that the RHR valve design prevents opening of the valves against a greater than 500 psi differential pressure, it is RG&E's conclusion that the possibility of an intersystem LOCA should not be a credible design basis. No additional modifications, such as diverse interlocks for the outboard valves, are warranted.

4. Staff position 5 states that "the operating procedures for the Ginna plant should be modified to direct the operator to cooldown and depressurize to RHR initiation parameters within 36 hours whenever the Service Water System is used for steam generator feedwater..." This position is based on the reference BNL-NUREG-28147, "Impure Water in Steam Generators and Isolation Condensers." We have had this report reviewed by NWT Corporation. NWT-167, "Use of Lake Ontario Water in Steam Generator During Hot Shutdown" (attached) concludes that, "although not recommended from the standpoint of maximizing component life, and operation for periods up to several days is not expected to result in any significant cracking or in deterioration of steam generator integrity."

RG&E therefore concludes that a specific directive to cool down and depressurize to RHR initiation conditions is not warranted, and should not be included in a procedure. The capability to do this does exist, however, and could be used if determined to be necessary at the time.

Attachment 2: RG&E responses to NRC letter of April 24, 1981 regarding SEP Topics V-11.A, "Isolation of High and Low Pressure Systems", V-11.B, "RHR Interlock Requirements", and VI-7.C.1, "Independence of Redundant Onsite Power Systems".

1. The Safety Evaluation for SEP Topic V-11.A, "Requirements for Isolation of High and Low Pressure Systems", specifies that the outboard RHR valves should have diverse interlocks to prevent opening when the RCS pressure is greater than RHR system design pressure.

   RG&E rationale for not providing these additional interlocks is provided in comment 3 of Attachment 1 of this transmittal.

2. The safety evaluation also required that interlocks be installed on the CVCS suction valves (200A, 200B, 202), to prevent a possible overpressurization of the CVCS letdown line outside containment. RG&E has noted in our March 27, 1981 letter on this SEP Topic that a relief valve (RV 203), with a capacity greater than the combined capacity of the three orifices, would relieve the pressure buildup caused by closure of the containment isolation valve 371. No overpressurization of the CVCS would thus be expected.

   RG&E has also evaluated the potential consequences of such an overpressurization event, with a subsequent small LOCA outside containment, and determined that no unacceptable consequences would result. This break would be a small LOCA outside containment (maximum flow of 140 gpm), and would be terminated by closure of valves 200A, 200B, and 202 either by operator action or automatically by low pressurizer level. Radiological consequences would be minimal, since no fuel damage would result. This event is specifically evaluated by SEP Topic XV-16, "Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment." RG&E has provided information concerning this topic by letter dated June 18, 1980 from L. D. White Jr. to Mr. Dennis M. Crutchfield.

   The RG&E conclusion is that, based on the availability of RV 203 to prevent overpressurization, together with the lack of unacceptable consequences due to an overpressurization, no interlocks or other modifications are required for the CVCS suction valves.

3. The safety evaluation further states that position indication is required on the CVCS discharge check valves. As stated in our March 27, 1981 letter on SEP Topic V-11.A, we do not believe that this line should be classified as a low pressure

system connected to the RCS, since the piping is 2500-lb piping throughout its length (to the positive displacement charging pump). RG&E has had no experience with failures of the positive displacement charging pump pistons to hold primary system pressure, nor would any failures be anticipated. Our contention that the charging line is not a line of concern is borne out by a memo from Edson G. Case to Raymond F. Fraley, "Isolation of Low Pressure Systems from Reactor Coolant System", dated July 11, 1977. That letter transmitted an NRC study of this subject to the ACRS, and evaluated all potential lines of concern. The charging line was not included.

To verify that the charging line was not a valid "Event V" concern, RG&E calculated the PWR Check Valve Event Tree (Section 4.4 of WASH-1400), using the charging line configuration (two in-series check valves and a charging pump piston). Very conservatively assuming that both check valves were undetected open, and that the probability of the charging pump piston failure was equal to a check valve failure, the $\overline{Q}_{SUM}$ calculated for this configuration was determined to be 1.4×10^{-8}/year. This is a low enough value to obviously be of no concern.

RG&E therefore considers that check valve position indication is not needed on the charging line check valves.

4. With respect to the SEP Topic Assessment V-11.B, no comments are necessary, since the resolution of outstanding issues is addressed in the topic assessment for SEP Topic V-11.A.

5. The additional information requested for SEP Topic VI-7.C.1 is presently being developed. It is anticipated that this information can be furnished to the NRC by July 15, 1981.

Attachment 3: RG&E responses to NRC letter of April 2, 1981, concerning SEP Topics VII-3, "Electrical, Instrumentation, and Control Feature of Systems Required for Safe Shutdown", and VIII-2, "Diesel Generators".

It appears that all comments provided by RG&E in our January 23, 1981 and January 30, 1981 letters concerning these topics have been properly incorporated.

Based on the resolution of all open items, and the removal of diesel generator testing from SEP Topic VIII-2, RG&E concludes that both of these topics are complete, with no outstanding issues to be carried into the Integrated Assessment.

NWT 167
February 1981

USE OF LAKE ONTARIO WATER IN STEAM GENERATORS DURING HOT SHUTDOWN

W. L. Pearl
S. E. Copley
J. Leibovitz

Prepared for Rochester Gas & Electric Company

NWT Corporation
7015 REALM DRIVE, SAN JOSE, CALIFORNIA 95119

INTRODUCTION

The possibility of using Lake Ontario water as an emergency PWR feedwater supply for more than 36 hours during which the plant would be brought to cold shutdown is being considered. The maximum steaming rate during such a period would be 100,000 pounds/h (200 gpm) at a temperature of 350°F. As a consequence of steaming, impurities of the untreated Lake Ontario water will concentrate in the steam generator. Of major concern is the possible risk of stress corrosion cracking (SCC) of steam generator materials in contact with the concentrated solution thus formed. To address this concern, the chemistry variation in the liquid phase as steaming proceeds at 350°F was estimated with emphasis on pH. Then, the possible potential for SCC was assessed on the basis of these estimates and available SCC data.

pH VARIATION AT 350°F UPON STEAMING LAKE ONTARIO WATER

A. Computer Modeling

The composition of Lake Ontario water as determined by RGE is given in Table 1.[1]

TABLE 1
LAKE ONTARIO WATER ANALYSIS
ppm

Calcium	35	Nitrate	2.5
Magnesium	8	Phosphate	0.3
Sodium	13	Fluoride	0.15
Potassium	3.6	Silica (as SiO_2)	0.25
Aluminum	0.1	Dissolved Oxygen	9.5
Chloride	32	Ammonia (as Nitrogen)	0.24
Sulfate	35		

Estimates of the water chemistry variation upon steaming were developed using the following assumptions:

1. Since aluminum and silica are in stoichiometric proportion in Lake Ontario water (Table 1), they are assumed to precipitate as aluminum silicate (clay) upon concentrating and therefore are removed from solution.

2. Since calcium occurs in the water (Table 1) in large excess over phosphate, it is assumed to precipitate all the phosphate as calcium hydroxy apatite ($Ca_5(PO_4)_3OH$) and remove it from the solution. The calcium in solution is decreased by the corresponding amount.

3. Fluoride and nitrite are assumed to behave as chloride. Potassium is assumed to behave as sodium.

4. Sodium and chloride in solution are assumed to remain completely dissociated.

5. Calcium carbonate precipitation is neglected. Degasification of CO_2 by steaming is assumed to occur.

6. The concentration of sodium and calcium chlorides is assumed limited by a solubility of 5 molal.

7. Chemical equilibrium expressions of references 2 and 3 apply.

On this basis, the liquid solution pH variation upon steaming at 350°F was estimated as a function of concentration factor defined as the mass ratio of total water (steam + liquid) to liquid water residual. The results are presented graphically in Figure 1. It is important to note that the definition of pH used here is that followed by Mesmer[4] in the determination of the dissociation constant of water at high temperatures, viz, the negative of the logarithm of the hydrogen ion concentration (not of its activity). Similarly, neutral pH is defined as that where the hydrogen and hydroxyl ion concentrations are equal. This neutral pH is a function of ionic strength. Therefore, the pH variation of the concentrated solutions must be considered in relation to that of neutral pH, also plotted in Figure 1. For basic solutions as is the case considered here, it is important to bear in mind that the hydroxyl ion concentration is expressed in terms of pH as follows:

$$C_{OH^-} = 10^{pH-2NpH}$$

(where NpH is the neutral pH value) and that when the neutral pH varies together with the ionic strength as the liquid solution is being concentrated upon steaming, the basicity of the solution may not be appreciated from the solution pH alone. The equivalent NaOH concentration is more suitable for this purpose and is plotted also in Figure 1.

B. Discussion

Steam Generator Bulk Water

Based on a maximum feed rate of 200 gpm to the steam generator and a total steam generator liquid volume of approximately 12,000 gallons, a maximum of one steam generator volume is steamed away each hour. Therefore, under maximum steaming conditions, the concentration factor achieved in the bulk steam generator water is t + 1 where t is the number of hours of steaming.

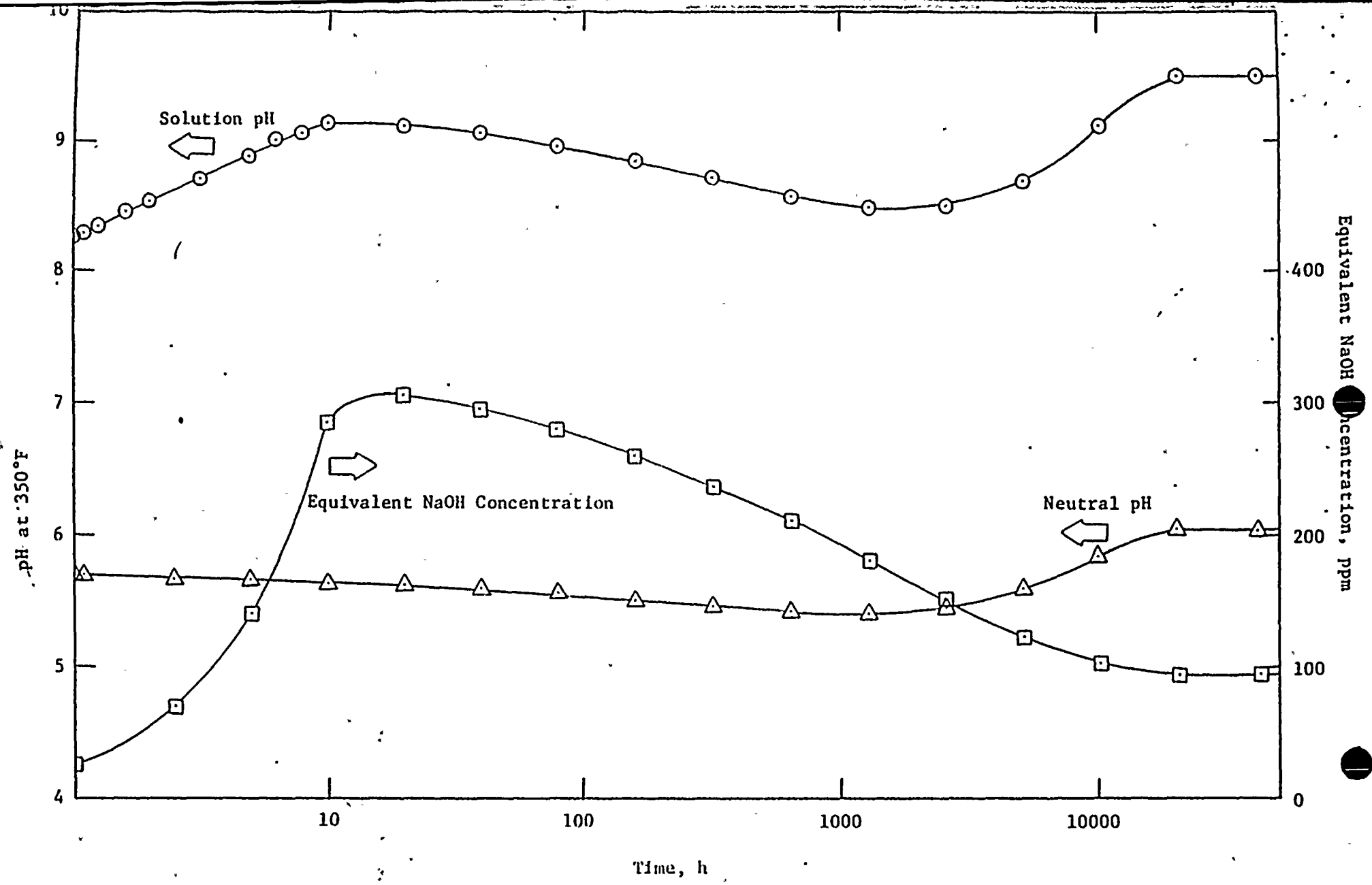

Figure 1. Variation of Steam Generator pH with Steaming at 350°F (feeding Lake Ontario water at 200 gpm)

The variation with time of the equivalent sodium hydroxide concentration in the steam generator with steaming of emergency Lake Ontario feedwater then can be followed on Figure 1. It is seen that a maximum equivalent NaOH concentration of about 300 ppm will be reached in the steam generator bulk water when 15 to 20 steam generator volumes will have been converted to steam, i.e., in approximately twenty hours. Further boiling should then decrease the equivalent NaOH concentration as magnesium and/or calcium hydroxides and/or calcium sulfate precipitate with increased concentrating. The decrease reaches a limit (at about 20,000 steam generator volumes converted to steam, i.e., in 20,000 hours) when sodium and calcium chlorides start to precipitate also. This limit is estimated at about 100 ppm equivalent NaOH for Lake Ontario water composition as specified in Table 1 and with the assumptions already stated. The assumptions seem reasonable and, at any rate, can be tested experimentally with a small autoclave from which known amounts of Lake Ontario water would be boiled away at 350°F at constant liquid level in the autoclave.

Crevices

The estimated equivalent NaOH solution concentration in steam generator crevices will depend upon the relative degree of crevice solution concentration above the bulk water. In tube to tube support plate crevices, there may be a distribution of relative concentration factors of unity and higher.

The chemistry in a crevice would lead that of the bulk in the sense that the chemistry of a specific crevice would travel the same curve (Figure 1) as the bulk but would be at a point on the curve somewhat ahead of the bulk. Since the causticity of Lake Ontario water is not a strong function of concentration, this does not pose a problem. Indeed it is expected in this case that after a short period of steaming, the crevice chemistry will be less basic than that of the bulk.

Cooling Water Composition

The NWT chemistry modeling work discussed herein is based on the chemical composition of Lake Ontario water summarized in Table 1 as supplied by RGE.

It is possible that seasonal changes in the characteristics of the lake water may result from the interrelation between source river flowrates, industrial pollution and/or acid rain. NWT has no relevant data to assess such effects.

It may be desirable that analyses made of Lake Ontario water during different seasons and under various conditions be fed into the NWT chemistry model. In this manner the safety of feeding Lake Ontario water, over the range of likely chemical compositions, can be verified.

POTENTIAL FOR SCC

A. Corrosion

The most aggressive solution expected based on the modeling work is 300 ppm NaOH, with ≤10 ppm O_2 (see below) at 350°F. Although laboratory data regarding these exact conditions are not available, data are available which can be extrapolated to assess the maximum corrosion rates expected for a given range of conditions.

van Rooyen and Kendig[5] cite Westinghouse data indicating that U-bends of Alloy 600 in deaerated 10% NaOH crack after several months of exposure. Figures 2 and 3 summarize Westinghouse tests[6] which show that at least 100 days of exposure to deaerated 10% NaOH at 600°F is required to produce a detectable crack in stressed Alloy 600.

Figure 4 shows data gathered by Berge and Donati.[7] These curves are for yield stressed C rings at 660°F. Extrapolating the curve for mill annealed Alloy 600 to 300 ppm NaOH yields a minimum time of 3500-4000 hours to induce a 0.5 millimeter crack.

The data presented above are for deaerated systems and are consistent with van Rooyen's[5] conclusion that Alloy 600 in 10% NaOH would not crack for several months. In the presence of oxygen, the susceptibility of Alloy 600 to SCC may be increased. Figure 5 shows stress corrosion behavior in 600°F high purity water containing varying amounts of oxygen in the gas phase above the water and adjusted to pH 10 at startup with ammonia.[8] As the oxygen content of the gas phase increased, the percent of the specimens attacked and extent of the attack increased. As noted in Figure 5 the average life in the 18-week test varied from no cracking with 1% oxygen in the gas phase (≤2 ppm oxygen in the water) to 7 weeks with 100% oxygen in the gas phase (≤200 ppm oxygen in the water).

McIlree and Michels[9] and later Sedriks, et al.,[10] reported less than 20% cracking after 27 days for Alloy 600 (2 common heat treatments) in aerated, 50% NaOH at 570°F.

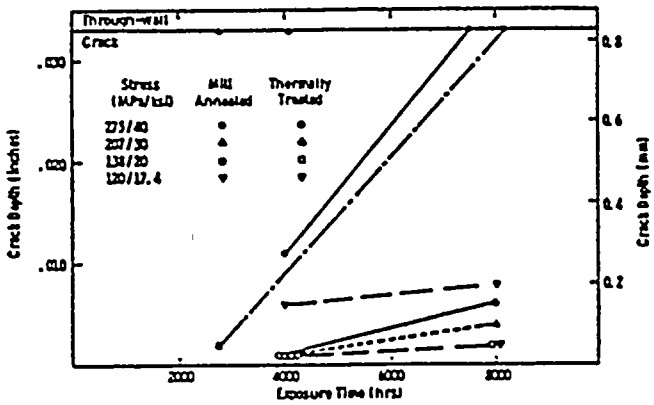

Figure 2. Crack Depth as a Function of Time, Stress Level and Material Condition for ID Pressurized Capsules Exposed to Deaerated 10% NaOH at 600°F[6]

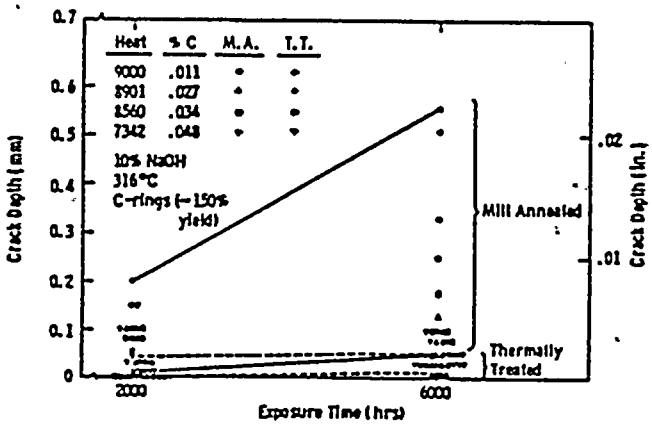

Figure 3. Crack Depth as a Function of Exposure Time for Mill Annealed and Thermally Treated Inconel Alloy 600 Exposed to Deaerated 10% NaOH at 600°F[6]

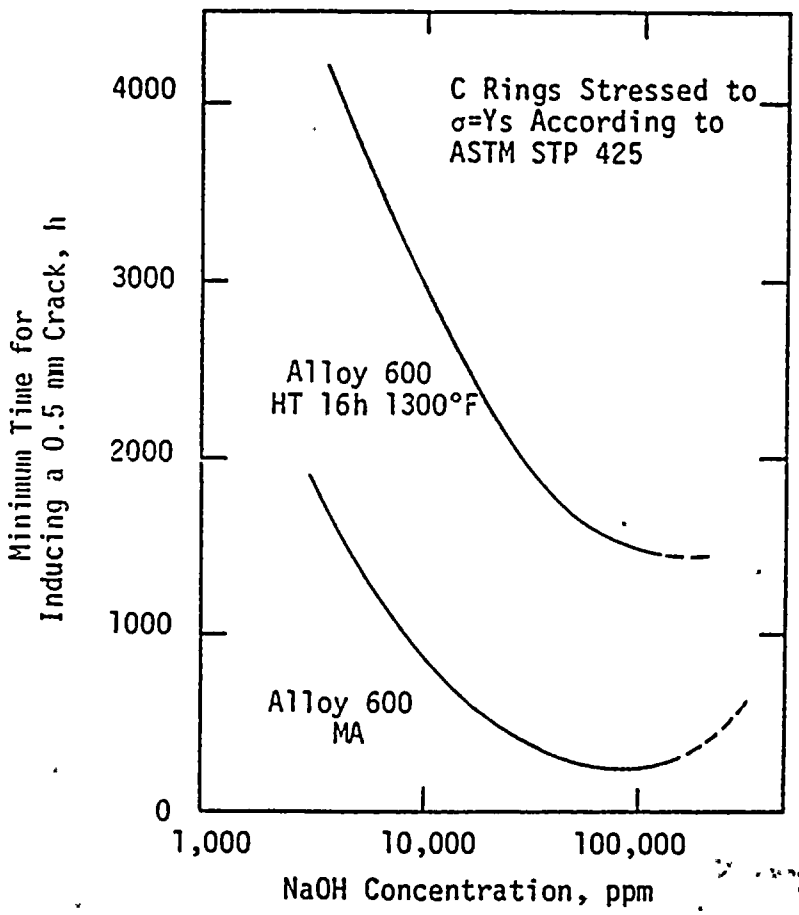

Figure 4. Resistance to Stress Corrosion Cracking of Alloy 600 Mill-Annealed or Heat Treated at 1300°F as a Function of Deaerated Sodium Hydroxide Concentration at 600°F[7]

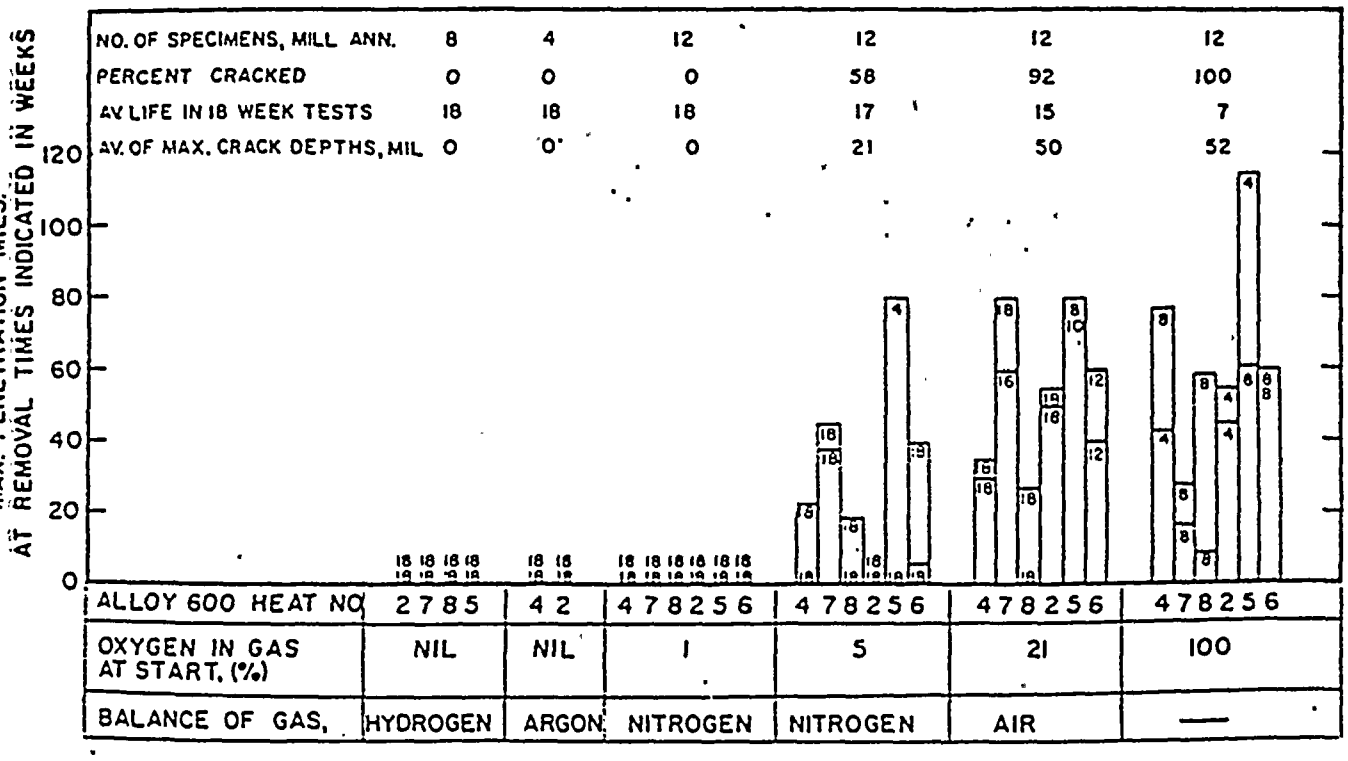

Figure 5. Stress Corrosion Behavior in Crevice Areas in Mill Annealed Inconel 600 Double U-bend Specimens in 600°F High Purity Water Adjusted to pH 10 with Ammonia at Startup[8]

Laboratory studies show that there is a significant temperature dependence of caustic stress corrosion cracking as illustrated in Figures 6 and 7. These results are for pressurized capsules exposed to 10% and 50% NaOH at varying stresses at temperatures ranging from 650 to 550°F. As can be seen, reducing the temperature below 600°F significantly extends the time for SCC to occur. This temperature dependence is further illustrated in Figure 8 where temperature is plotted versus rate constant for both 10% and 50% NaOH.

B. Oxygen

The lake water fed to the generators probably would be air saturated (approximately 10 ppm O_2). However, at 350°F the K_D (the equilibrium ratio between steam phase and liquid phase) for oxygen is slightly greater than 5000. Even though the dynamic distribution in practice may not reach true equilibrium conditions, the net effect of the high K_D value is that recriculated steam generator coolant will contain oxygen concentrations lower than 10 ppm. This recirculated coolant will dilute the oxygen concentration of incoming feedwater with a net oxygen level in the downcomer of ~1 to 10 ppm, depending on the recirculation ratio under the contingency conditions.

C. Conclusion

With the significantly lower concentrations of sodium hydroxide (max 300 ppm), oxygen concentration ≤10 ppm and the lower temperature (350°F) involved, the contingency of feeding Lake Ontario water to the Ginna steam generators should result in no measureable damage to steam generator internals. Although not recommended from the standpoint of maximizing component life, such operation for periods up to several days is not expected to result in any significant cracking or in a deterioration of steam generator integrity.

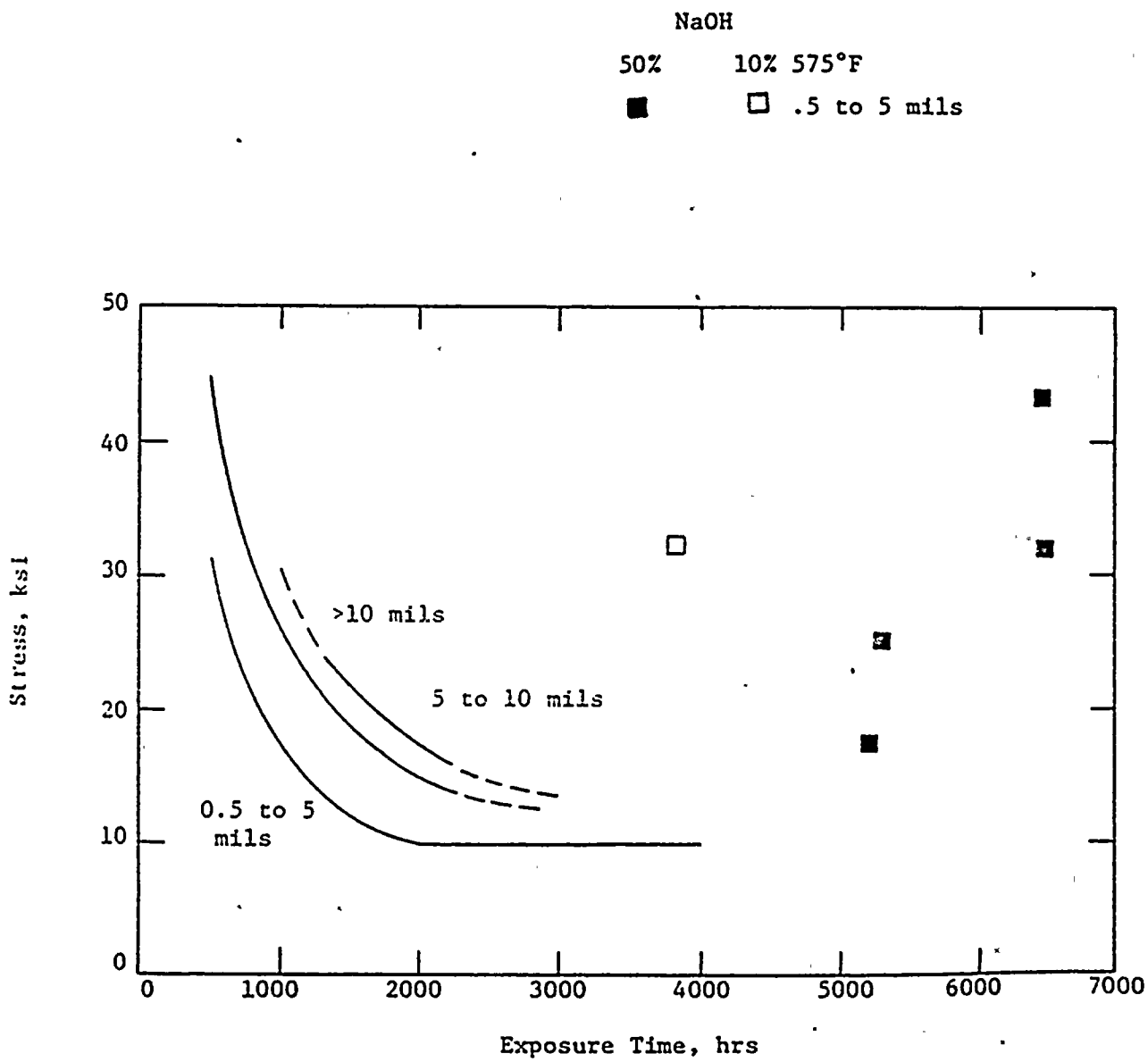

Figure 6. Caustic Cracking of Mill Annealed Alloy 600 at 575°F
(Lines depict zones of crack depth from 10% NaOH at 600°F)

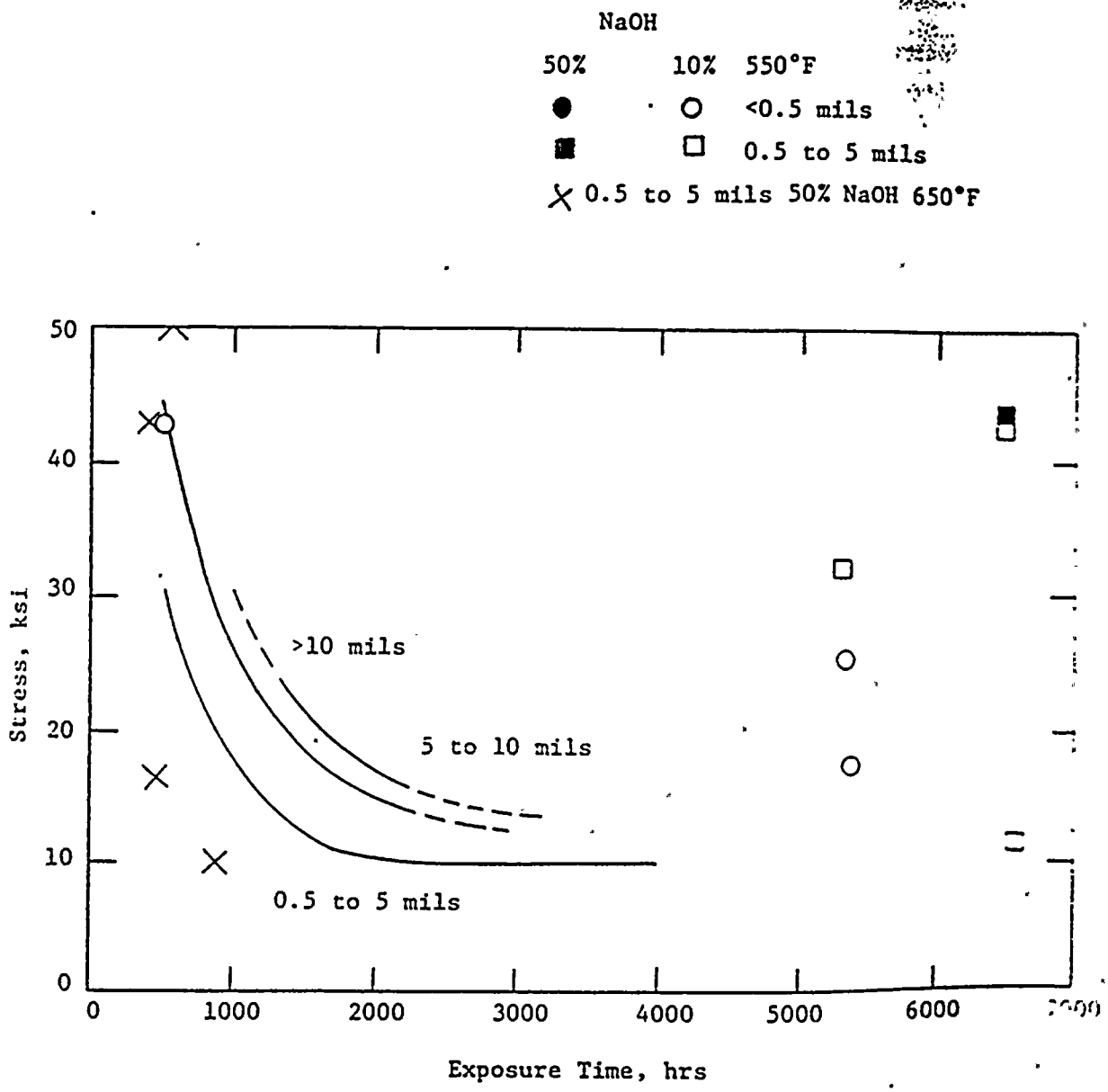

Figure 7. Caustic Cracking of Mill Annealed Alloy 600 at 550°F and 650°F (Lines depict zones of crack depth from 10% NaOH at 600°F)

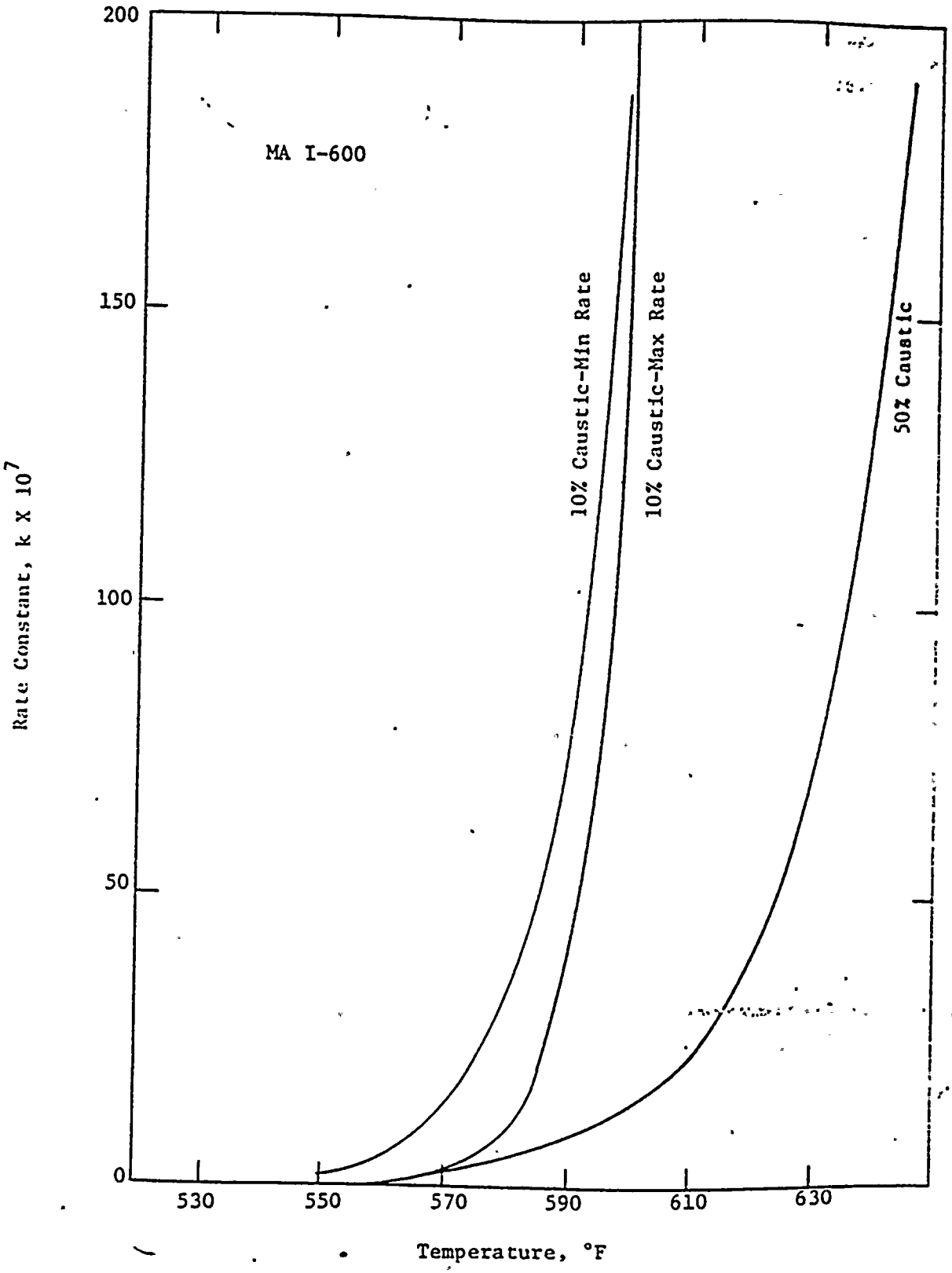

Figure 8. Indicated Variation in Rate of SCC with Temperature

COMMENTS ON VAN ROOYEN AND KENDIG'S REPORT[5]

The referenced report[5] basically is a broad summary covering a large volume of data applicable in part to stainless steels and in part to Alloy 600. We are generally in agreement with their nine summary conclusions, but find it difficult to apply their broad-brush treatment to the specifics of a PWR hot shutdown with lake water added to the steam generators at 350°F. Their document is misleading for such an application in two respects:

1. Caustic Concentration

Their statement that ..."For the purposes of SCC predictions, it has to be assumed that the time to form dangerous levels of NaOH, once impurities have been introduced, is short, i.e., one day or less" does not fully recognize the specific concentration chemistry of the cooling water involved nor the low heat flux available and the cutback in steaming rate during a period of hot shutdown. In the case of the Lake Ontario water, for example, the maximum NaOH concentration reached is 300 ppm (after steaming ~20 steam generator volumes) with a decrease in concentration thereafter.

2. Temperature

All of the test work referenced in the referenced report[5] was performed in the temperature range of 550 to 630°F. With the significant temperature dependence of caustic SCC as shown above, the concern at 350°F is many times less than is indicated from the data quoted by the authors.[5]

Based on the above three considerations, it is our assessment that the generalized time limit of 36 hours in the report[5] is not directly applicable to the Ginna steam generators steaming at 350°F while fed by Lake Ontario water.

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