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Constellation Energy
Generation Group

February 16, 2006

U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

ATTENTION: Document Control Desk

SUBJECT: **R.E. Ginna Nuclear Power Plant**
Docket No. 50-244

Response to Requests for Additional Information Regarding Topics Discussed on Conference Calls

By letter dated July 7, 2005, as supplemented by letters dated August 15 and September 30, 2005, R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC) submitted an application requesting authorization to increase the maximum steady-state thermal power level at the R.E. Ginna Nuclear Power Plant from 1520 megawatts thermal (MWt) to 1775 MWt.

Over the period spanning January 30, 2006 through February 8, 2006, the NRC staff engaged the Ginna Extended Power Uprate Project Team with discussions involving the Extended Power Uprate (EPU) Licensing Submittals. Through out the course of these discussions both staff and station personnel have kept meeting minutes. Ginna has reviewed the staff minutes promulgated on the public docket as well as our own records to ensure all information requested by the staff has been provided.
The purpose of this letter is to provide formal documentation of any outstanding requests received to date as well as our response. Our responses are contained in Attachments 1 through 6. Each attachment represents a specific conference call.

Attachment 1 contains the questions and answers resulting from a January 30, 2006 conference call.

Attachment 2 contains the questions and answers resulting from a January 31, 2006 conference call and can be associated with an NRC letter dated October 25, 2005 (initial response provided in Constellation letter dated December 6, 2005).

Attachment 3 contains the questions and answers resulting from a February 2, 2006 conference call.

Attachment 4 contains the questions and answers resulting from a follow up on the February 2, 2006 conference call also held on February 2, 2006 and can be associated with an NRC letter

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dated October 25, 2005 (initial response provided in Constellation letter dated December 6, 2005.)

Attachment 5 contains the questions and answers resulting from a February 6, 2006 conference call.

Attachment 6 contains the questions and answers resulting from a February 8, 2006 conference call.

The responses do not include any new regulatory commitments.

If you have any questions, please contact George Wrobel at (585) 771-3535 or george.wrobel@constellation.com.

Very truly yours,

Mary G. Korsnick

Mary G. Korsnick

STATE OF NEW YORK :
: **TO WIT:**
COUNTY OF WAYNE :

I, Mary G. Korsnick, being duly sworn, state that I am Vice President – R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC), and that I am duly authorized to execute and file this response on behalf of Ginna LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Ginna LLC employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Mary G. Korsnick

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Monroe, this 16 day of February, 2006.

WITNESS my Hand and Notarial Seal:

Sharon L Miller
Notary Public

My Commission Expires:

SHARON L. MILLER
Notary Public, State of New York
Registration No. 01MI6017755
Monroe County
Commission Expires December 21, 2006

Attachments

Cc: S. J. Collins, NRC
P. D. Milano, NRC
Resident Inspector, NRC

Mr. Peter R. Smith
New York State Energy, Research, and Development Authority
17 Columbia Circle
Albany, NY 12203-6399

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NYS Department of Public Service
3 Empire State Plaza, 10th Floor
Albany, NY 12223-1350

ATTACHMENT 1
QUESTIONS AND ANSWERS RESULTING FROM A JANUARY 30, 2006 CONFERENCE CALL

NRC Question #1: Provide thermal parameters associated with the nominal power level of 1775 MWT.

Ginna Response: The thermal parameters associated with the uprate condition at the nominal power level of 1775 MWT are provided in Table 1 below. Note that the assumed RCS flow is the thermal design flow of 85,100 gpm and the vessel average temperature is either the design maximum or design minimum.

Table 1
NSSS PCWG Parameters for Ginna Station Uprate Program

Thermal Design Parameters	Current[c]	EPU Case 1	EPU Case 2	EPU Case 3	EPU Case 4
NSSS Power	100	117.2	117.2	117.2	117.2
MWt	1520	1781	1781	1781	1781
10^6 Btu/hr	5,186	6,077	6,077	6,077	6,077
Reactor Power MWt	1520	1775	1775	1775	1775
10^6 Btu/hr	5,186	6,057	6,057	6,057	6,057
Thermal Design Flow, loop gpm	85,100	85,100	85,100	85,100	85,100
Reactor 10^6lb/hr	64.6	65.8	65.8	64.8	64.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	6.5[a]	6.5[a]	6.5[a]	6.5[a]	6.5[a]
Reactor Coolant Temperature, °F					
Core Outlet	607.8	604.7	604.7	615.4	615.4
Vessel Outlet	603.9	600.3	600.3	611.1	611.1
Core Average	576.9	568.6	568.6	580.2	580.2
Vessel Average	573.5	564.6	564.6	576.0	576.0
Vessel/Core Inlet	543.1	528.9	528.9	540.9	540.9
Steam Generator Outlet	603.9	528.7	528.7	540.6	540.6
Steam Generator					
Steam Outlet Temperature, °F	513.8	507.5	504.2	519.8[b]	516.5
Steam Outlet Pressure, psia	770	728	707	811[b]	788
Steam Outlet Flow, 10^6 lb/hr total	6.60	7.27/7.72	7.27/7.72	7.29/7.75[b]	7.29/7.74
Feed Temperature, °F	425	390/435	390/435	390/435	390/435
Steam Outlet Moisture, % max.	0.10	0.10	0.10	0.10	0.10
Design FF, hr. sq. ft. °F/Btu	0.00015	0.00015	0.00015	0.00015	0.00015
Tube Plugging Level (%)	0	0	10	0	10
Zero Load Temperature, °F	547	547	547	547	547
Hydraulic Design Parameters					
Pump Design Point, Flow (gpm)/Head (ft.)	90,000/252				
Mechanical Design Flow, gpm	101,200				
Minimum Measured Flow, gpm/total	177,300				

Notes:
Core bypass flow includes 2.0% due to Thimble Plug Removal.
If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 861 psia, steam temperature of 526.8°F, and steam flow of 7.76 x 10^6 lb/hr total should be assumed. This envelopes the possibility that the steam generator could perform better than expected.
c. Current parameters obtained from Tables 4.4.1 and 5.4.2 of UFSAR.

ATTACHMENT 2
QUESTIONS AND ANSWERS RESULTING FROM A JANUARY 31, 2006 CONFERENCE CALL

NRC Question #1

With respect to operational experience used in developing the Ginna EPU test plan, this response is provided as supplementary information to RAI question #1 in NRC letter dated October 25, 2005 (initial response provided in Constellation letter dated December 6, 2005):

Standard Review Plan (SRP) Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," specifies in Part III.C, the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be considered for inclusion in the EPU test program. Previous operating experience should be considered, as applicable, when justifying elimination of power-ascension tests.

In Section 2.12, "Power Ascension and Testing Plan," of the licensing report, the licensee stated that "operating experience has been incorporated into the proposed test plan."

However, the licensee has not provided information of specific operating experience incorporated into their proposed test plan. Provide additional information regarding specific examples of operating experiences incorporated into the proposed test plan.

Ginna Response

Ginna has done extensive reviews of industry operating experience associated with plant uprates at other facilities and will be incorporating lessons learned from this experience in a number of ways to facilitate uprate implementation: e.g. modification scope and design, operator training, procedure development and testing. One aspect of the operating experience review that will permeate the test program is incorporation of applicable operating experience into pre-job briefs for all test procedures that will be performed. In addition, below is a list of specific examples where operating experience will be used to enhance test procedures. Since the detailed test procedures have not been written, and since our operating experience review continues, we expect that there will be additional examples of how operating experience is used to enhance the test program when the procedures are fully developed.

The vibration monitoring plan will be enhanced based on industry failures of small bore piping and other components due to vibration induced fatigue. Ginna has reviewed the industry events caused by vibration post power uprate, including such events as main steam relief valve pilot valve vent line failure and lift setpoint drift, turbine control valve hydraulic fluid accumulator tubing failure, main steam low point drain pipe failure, turbine hydraulic fluid pump skid piping and pressure switch failures, feedwater regulating valve solenoid valve failure and feedwater heater level control valve and positioner failures. As a result of this industry experience, the vibration monitoring program will be enhanced to include monitoring of all of these components. In addition, all branch lines attached to lines that will see an increase in process fluid flow have been included in the scope of lines to be closely monitored.

The power escalation test plan will include a turbine valve stroke test in part as a result of industry experience including load instability during valve testing and load swings when transferring control from automatic to manual.

The power escalation test plan will also include turbine vibration monitoring and detailed operator guidance to address turbine rubs as a result of industry experience with turbine rubs associated with mono-block rotors.

The post-modification test plan and power escalation test plan will be enhanced to include performance of Iso-Phase Bus Duct air flow testing and temperature monitoring as a direct result of industry experience with failures resulting from increased bus duct air flow and higher bus duct temperatures.

Additional walkdown monitoring points will be incorporated into the power escalation test procedure to verify that condenser hotwell and feedwater heater level control systems are operating properly throughout the power escalation process based on plant operating experience with these control systems prior to uprate.

As described in the Licensing Report Section 1.0, Introduction to the Ginna Station Extended Power Uprate

Licensing Report, use of industry operating experience, Ginna carefully considered the lessons learned accrued from industry experience with uprates.

NRC provided information such as event reports (e.g.: Event numbers 38916) and announced special inspections (e.g.: NRC news No. III-06-002), as well as information notices have provided valuable insights which are continuously applied to project engineering activities.

In addition to the data supplied by the NRC, other OE, not available to the general public, provided inputs. These included direct communication with other utilities who've under gone uprate as well as data supplied by the Institute of Nuclear Power Operations (INPO).

Specific additional details regarding the operating experience utilized in developing the Ginna EPU test plan can be found in the following INPO documents. Below each document is a brief description of how Ginna will incorporate the experience in the test plan in order to prevent a similar occurrence.

Event #s:

265-020402-1 Main Steam Low Point Drain Pipe Failure
Drain pipes attached to the main steam header will be included explicitly as an inspection points in the vibration monitoring plan.

278-951023-1 Turbine Hydraulic Fluid Pump Skid Pipe Failure
Although Ginna does not have a similar arrangement where a main steam pressure transmitter could transmit pulsations into the EHC hydraulic fluid, the EHC system will be a point of focus for the vibration monitoring plan.

237-020626-1 Turbine Hydraulic Fluid Pressure Switch Failure
Turbine control valve solenoid valves will be included explicitly as an inspection points in the vibration monitoring plan.

333-981028-1 Feedwater Heater Control Valve and Positioner Failure
Feedwater heater and drain systems will be included explicitly as inspection points in the vibration monitoring plan.

OE #s:

17530 Main Steam Relief Valve Pilot Valve Vent Line Failure
Although Ginna does not have a similar design main steam electromatic relief valve, the main steam safety valves will be included explicitly as inspection points in the vibration monitoring plan.

20915 Main Steam Relief Valve Lift Setpoint Drift
Although Ginna does not have a similar design main steam safety relief valve, the main steam safety valves will be included explicitly as inspection points in the vibration monitoring plan.

14149 Turbine Control Valve Accumulator Tubing Failure
As previously mentioned, the EHC system will be a point of focus for the vibration monitoring plan and tubing associated with the valves and the accumulators will be included as inspection points.

9684 Turbine Load Instability During Valve Testing
Ginna has verified that the turbine control valve stroke test pressure will not cause the plant to operate near a slope change in the control curve for the remaining valves.

12280 Tturbine Load Swings When Transferring Control From Automatic To Manual
Ginna plans to adjust the valve characteristic curves that position the turbine control valves after the initial startup to assure that any differences between the predicted and actual curves are accounted for.

20891 Turbine Rubs Associated with Monoblock Rotors
The power escalation test procedure will specifically not allow operation of the main turbine during the power escalation with a final stage feedwater heater out of service.

18874 Iso-Phase Bus Duct Failure Due To Increased Air Flow (see also SER 4-04)
A post modification air flow test will be conducted to verify the bus duct air flow is as expected and not within the range that could cause flow-induced vibration within the duct.

ATTACHMENT 2
QUESTIONS AND ANSWERS RESULTING FROM A JANUARY 31, 2006 CONFERENCE CALL

NRC Question #2

Provide additional discussion regarding the benchmarking of LOFTRAN to observed transients at plants subsequent to power uprates.

Ginna Response

Westinghouse performs Condition I operating transient analysis using the LOFTRAN code for all Westinghouse plants including Ginna. An extensive verification process for the LOFTRAN code has been completed by Westinghouse to confirm its applicability for Ginna. This verification process included benchmarking against actual plant operating data which is documented in WCAP-7907-P-A, a topical report which has been reviewed and approved by NRC.

The LOFTRAN code is used for transient analysis of 2, 3 and 4-loop plants at various operating conditions (i.e., different power levels, various full power Tavg and feedwater temperature conditions, various steam generator types (preheat and feed ring, and different tube plugging levels) and, hence, the LOFTRAN simulation for the Ginna plant at EPU conditions will accurately predict the plant performance independent of power level. However, the NRC has requested specific benchmarking information for plants where events have occurred subsequent to a power uprate.

In particular, the LOFTRAN code was used for the Kewaunee uprate project to predict the plant performance at uprate conditions (1772 MWT). Kewaunee is a 2-loop sister plant to Ginna and very similar in design. A recent event occurred at Kewaunee, on November 28, 2005, which confirms LOFTRAN ability to predict the plant performance. The event involved loss of one main feedwater pump while operating at full power which led to a reactor trip. The following results from the actual plant transient were confirmed in the prior LOFTRAN analysis:

1. The LOFTRAN code predicted the pressurizer and steam generator safeties would not open if the steam dump control and pressurizer pressure/level controls worked properly. During the real event, neither the pressurizer safeties nor steam generator safeties opened.
2. The LOFTRAN code also predicted that there would be no safety injection if the reactor control and pressurizer pressure control worked properly. During the real event, there was no safety injection actuation.
3. In addition, the event confirmed the capability of control rod and turbine control to reduce the core power.

In addition to the Kewaunee event, a reactor trip occurred at Farley after their power uprate, on May 27, 1999. Farley is a 3-loop Westinghouse design. The event was initiated by a loss of feedwater pump and the reactor tripped. Again, the plant performance was comparable to the LOFTRAN prediction - no safeties opened, no safety injection occurred and the plant stabilized at no-load temperature due to proper control system operation.

These events confirm that LOFTRAN can predict proper plant performance during transients after power uprate.

ATTACHMENT 2
QUESTIONS AND ANSWERS RESULTING FROM A JANUARY 31, 2006 CONFERENCE CALL

NRC Question #3

Provide copies of the original Startup Test Reports for Ginna.

Ginna Response

The original Startup Test Reports are as follows:

- SUMMARY OF STARTUP TESTING EXPERIENCE AT GINNA NUCLEAR POWER PLANT UNIT - NO. 1 – January 6, 1971
- ROCHESTER GAS AND ELECTRIC CORPORATION POWER ECALATION TO 1520 MWt –March 1972

WD001947

APPENDIX A

SUMMARY OF STARTUP TESTING EXPERIENCE

AT GINNA NUCLEAR POWER PLANT

UNIT NO. 1

ROCHESTER GAS AND ELECTRIC CORPORATION

January 6, 1971

75544

Summary of Startup Testing Experience
at Ginna Nuclear Power Plant

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SUMMARY OF STARTUP TESTING EXPERIENCE AT GINNA NUCLEAR POWER PLANT

I. Safety Injection Systems Pre-Operational Tests

A. Valve Functional Test

This test constitutes the portion of RG&E S. U. -4. 5. 1 from steps 7. 0 through and including steps 7. 9. The purpose of this section was to verify the operation of all safeguards related valves and further, to verify valve status indicating light operation. It was necessary to perform this test several times because of design changes and construction status. It was decided that this section of the test would be rewritten to become all inclusive of safeguards equipment not covered by other safeguard tests. At the time that the test was rewritten, the plant was involved in "hot functional testing," so the test was written facilitating testing at either "hot" or "cold" shut-down conditions. The purpose of the rewritten test designated "Safety Injection Functional Test" was:

1. To verify the operation of the steam line isolation sequence.
2. To verify that the proper sequencing and operation of valves, circuit breakers, and diesel generators occurs on initiation of safety injection and containment spray signals.
3. To verify the operation of indicating and status lights of the above mentioned equipment.

4. To verify that the proper safeguards equipment is operated with each of the two logic trains.
5. To initiate a safeguards signal by simulating an abnormal condition to transmitters related to safeguard systems.
6. To verify the operation of the motor driven auxiliary feed pumps by simulating a lo-lo steam generator signal.
7. To verify the operation of the steam driven auxiliary feed pump by simulating a lo-lo steam generator level signal in both steam generators.

The operation of the steam line isolation sequence, the operation of the motor driven feedwater pumps and the steam driven feedwater pumps by their respective safety signal from both the "A" and "B" logic trains was performed satisfactorily.

The proper operation of the diesel generators was witnessed for both logic trains.

Proper sequencing and operation of safeguard valves and the proper operation of their respective indicating and status lights upon receiving a safety injection and/or containment spray signal was satisfactorily performed with the results tabulated as in Figures I. 1 and I. 2 which typify data sheets used.

The following circuit breakers were tested coincidental with the safety injection valves and initiated by the same safety injection signal as that which actuated the safeguard valves.

BREAKER	BUSSES	
52/BT 17 - 18	(tie breaker between busses 17 and 18)	
52/BT 16 - 15	(tie breaker between busses 15 and 16)	
52/BT 14 - 13	(tie breaker between busses 14 and 13)	
52/FP	fire pump	17
52/IHIA	intake heaters	18
52/IHIB	intake heaters	17
52/IHIC	intake heaters	18
52/IHID	intake heaters	17
52/MCC 1G1	screen house motor control center	18
52/MCC 1G2	screen house motor control center	17
52/BT 16 - 14	(tie breaker between busses 14 and 16)	
52/CCP 1A	component cooling pump 1A (Note 4)	14
52/CCP 1B	component cooling pump 1B (Note 4)	16
52/CHP 1A	charging pump 1A	14
52/CHP 1B	charging pump 1B	16
52/CHP 1C	charging pump 1C	16
52/PHBG	pressurizer heater backup group	16
52/PHCG	pressurizer heater control group	14
52/FP 1A, 1B	main feedwater pumps	

As with the valves, the breakers listed in this step were tested one logic train at a time to insure that each train functions properly.

In order to insure that each breaker works properly, it was necessary to initiate the safety injection signal a number of times. The procedure and results will be combined in this writeup.

Safety injection was initiated in Test 1 through 6 by turning the block-unblock switch on the MCB to the unblock position.

TEST 1

This was a test of the A train logic so the power was removed from the B train logic by turning off circuit 9 of D.C. control panel 1B.

52/BT 17 - 18 was closed so that bus 17 was fed from bus 18.

52/BT 16 - 15 was closed so that bus 15 was fed from bus 16.

52/BT 14 - 13 was closed so that bus 13 was fed from bus 14.

These three breakers tripped on safeguard initiation.

52/FP1A, 52/FP1B, reactor trip breaker A, reactor trip breaker B and the fire pump breaker were closed but then tripped on a safety injection signal.

The intake heater breakers and 52/MCC1G1 were closed.

52/IH1A, 52/IH1C and 52/MCC1G1 tripped because of safety injection and 52/IH1B, and 52/IH1D tripped because of under-voltage on bus 17. This was determined by closely watching the breaker indicators on the breakers themselves. By close coordination with the control board it was determined that

52/IH1A, 52/IH1C, and 52/MCC1G1 tripped immediately upon safety injection initiation. Thus, it was assumed that these three trips were caused by the safety injection signal. 52/IH1B, and 52/IH1D are fed from bus 17, thus, in this case these two heaters tripped on undervoltage a second or so after the previous three breakers tripped.

Test 1 thus was performed satisfactorily.

TEST 2

This was also a test of logic train A, but tested the tripping of other breakers. Power was not restored to logic train B.

52/BT 17 - 18 was closed so that bus 18 was fed from bus 17.

52/BT 16 - 14 was closed so that bus 16 was fed from bus 14.

Both of these breakers tripped on safeguard initiation.

Breakers 52/FP, 52/IH1B, 52/IH1D, 52/CCP1B, and 52/MCC1G2 were closed prior to initiating safety injection and remained closed after initiation of that signal. This is because these breakers are tripped from logic train B, not logic train A.

Breaker 52/CCP1A was closed and did trip on the safety injection signal. This was caused because of the safety injection signal combined with the tripping of bus 14. Bus 14 tripped because the safety injection signal combined with the undervoltage on bus 18. This undervoltage on bus 18 was caused

by safety injection because bus 18 was being supplied with power from bus 17 via 52/BT 17 - 18, 52/IH1A, and 52/LH1C were closed. Through close coordination between the control board and the man at the circuit breakers, it was found that these two breakers tripped immediately upon initiating safety injection and not a second later. This indicates that these breakers tripped because of the safety injection signal and not because of the undervoltage condition on bus 18.

52/CHP1A, and 52/PHCG were closed and did trip when safety injection was initiated. It was later realized that these trips could have been caused by either the safety injection signal or the undervoltage signal that occurred on bus 14. These were tripped by pressing the buttons on SI-11X and SI-12X. Both breakers tripped.

Test 2 thus was performed satisfactorily.

TEST 3

This was a continuation of the testing of logic train A. Power, therefore, was not restored to train B logic.

52/BT 16 - 14 was closed so that bus 14 was fed from bus 16. On initiation of safety injection, this breaker tripped.

52/CCP1A, and 52/CCP1B were both closed. On initiating safety injection, 52/CCP1A, tripped and 52/CCP1B did not.

Test 3 thus was performed satisfactorily.

TEST 4

This was test of the B logic train so power was removed from the A train logic by turning off circuit 12 of D. C. control board panel 1A.

52/BT 17 - 18 was closed so that bus 18 was fed from bus 17.

52/BT 16 - 15 was closed so that bus 15 was fed from bus 16.

52/BT 14 - 13 was closed so that bus 13 was fed from bus 14.

These three breakers tripped on safeguard initiation.

52/FP1A, 52/FP1B, reactor trip breaker A, reactor trip breaker B, and the fire pump breaker were closed and did trip on a safety injection signal.

The intake heater breakers and 52/MCC1G2 were closed.

52/IH1B, 52/IH1D, and 52/MCC1G2 tripped because of safety injection and 52/IH1A and 52/IH1C tripped because of under-voltage on bus 18. This was determined by closely watching the breaker indicators on the breakers themselves. By close coordination with the control board, it was determined the 52/IH1B, 52/IH1D, and 52/MCC1G2 tripped immediately upon safety injection initiation. Thus, it was assumed that these three trips were caused by the safety injection signal.

52/IH1A, and 52/IH1C are fed from bus 18, thus, in this case these two heaters tripped on undervoltage a second or so after the previous three breakers tripped.

Test 4 thus was performed satisfactorily.

TEST 5

This was also a test of logic train B, but tested the tripping of other breakers. Power was not restored to logic train A. 52/BT 17 - 18 was closed so that bus 17 was fed from bus 18. 52/BT 16 - 14 was closed so that bus 14 was fed from bus 16. Both of these breakers tripped on a safeguard initiation. 52/IH1A, 52/IH1C, 52/MCC1G1, and 52/CCP1A were closed prior to initiating safety injection and remained closed after the initiation of that signal. This is because these breakers are tripped from logic train A, not logic train B. Breaker 52/CCP1B was closed and did trip on the safety injection signal. This was caused because of the safety injection signal combined with the tripping of bus 16. Bus 16 tripped because the safety injection signal combined with the undervoltage on bus 17. This undervoltage on bus 17 was caused by safety injection because bus 17 was being supplied with power from bus 18 via 52/BT 17 - 18. 52/IH1B, and 52/IH1D were closed. Through close coordination between the control board and the man at the circuit breakers, it was found that these two breakers tripped immediately upon initiating safety injection and not a second later. This indicates that these breakers tripped because of the safety injection signal and not because of the undervoltage condition that occurs on bus 17.

52/CHP1B, 52/CHP1C, and 52/PHBG were closed and did trip when safety injection was initiated. It was later realized that these trips could have been caused by either the safety injection signal or the undervoltage signal that occurred on bus 15.

52/CHP1B and 52/CHP1C were closed and then tripped by pressing the button on relay SI-21X. This worked properly.

52/PHBG was tripped by placing a jumper across contacts 19 and 23 of relay SI-22X.

Test 5 thus performed satisfactorily.

TEST 6

This was a continuation of the testing of logic train B. Power, therefore, was not restored to train A logic.

52/BT 16 - 14 was closed so that bus 16 was fed from bus 14. On initiation of safety injection, this breaker tripped.

52/CCP1A and 52/CCP1B were both closed. On initiating safety injection, 52/CCP1B tripped and 52/CCP1A did not.

Test 6 thus was performed satisfactorily.

TEST 7

This test assures that reactor trip breakers function on a manual safety injection signal in the A logic train. Test 1 on the other hand tests the A logic train on automatic safety injection signals.

Reactor trip breakers A and B were closed and the B logic train was shut off. The manual safety injection button was pushed and both breakers tripped. Logic train B was restored.

TEST 8

This test assures that reactor trip breakers function on a manual safety injection signal in the B logic train. Test 4 on the other hand tests the B logic train on automatic safety injection signals.

Reactor trip breakers A and B were closed and the A logic train was shut off. The manual safety injection button was pushed and both breakers tripped. Logic train A was restored to operation.

B. Accumulator Blowdown Test

Section 10 of RG&E S.U.-4.5.1, which describes the test procedure to be used in testing the safety injection accumulators, was revised to include a more detailed and comprehensive testing of the accumulators. The test had basically three goals:

1. Determine the magnitude of pipe displacement and stress resulting from reaction to the fluid blowdown.
2. Determine the amount of water forced back through the reactor coolant pump into the low portion of piping between the steam generator and pump suction.
3. Measure the blowdown transient for comparison with the analysis performed in the Final Safety Analysis Report.

Four test runs were made, each accumulator being subjected to both a run at 300 psig initial pressurization and 740 psig initial pressurization.

Strain and displacement readings were taken on each accumulator discharge line; measurements of the pressure-time transient were made and the volume of water collected in the loop seal region was measured for each run.

Pipe Reaction Results

The pipe displacements and stresses were measured under the supervision of Gilbert Associates and Brewer Engineering Laboratories. Pipe reactions were not excessive and are given quantitively in the Brewer Report, "Accumulator Piping Vibration Test Results."

Investigation of Water Blowback Through the Reactor Coolant Pump

During the design of the Ginna Station, the dynamics of the water jet entering the reactor coolant pipe were analyzed due to a concern that the accumulator flow might divide and flow back through the pump losing water intended for the reactor vessel.

There are two features of the reactor coolant pump which resist such backward flow. One is the diffuser assembly which forms a dam to flow within an inch or two of the top of the reactor coolant pipe at pump discharge. The other is the pumping action of the reactor coolant pump itself which, even while coasting down, strongly rejects water attempting to flow in reverse through the pump.

The analysis showed that the discharge of water into the reactor coolant pipe from the accumulator would cause the water level to rise above the diffuser assembly into the impeller.

The opinion of hydrodynamics consultant, Dr. V. L. Streeter of the University of Michigan, was that the configuration of the pump is such as to dissipate jet effects, requiring the spinning impeller only to prevent reverse flow against a foot or two of water head.

An analysis of the length of the pump deceleration transient under loss-of-coolant conditions and the pumping effect of the reactor coolant pump with a voided suction showed the pump will provide the necessary pumping effect to prevent reverse flow for the period required to assure effective delivery of accumulator water to the core.

This test showed that water did rise above the diffuser assembly and satisfied curiosity on this point.

Blowdown Transient Behavior

The blowdown flow transients showed well-behaved, predictable transients for three of the four runs. One anomalous run, the high pressure blowdown of the Loop B accumulator, occurred resulting in further investigation and analysis.

In spite of the bad run, the basic goals of the program were met.

1. The runs showed that the assumption of an adiabatic gas expansion used in the FSAR loss-of-coolant analysis was valid.

2. The runs showed that, for both accumulators, the piping resistance is about 2/3 of the value used in the FSAR analysis providing a flow margin about 15% over the flow initially calculated for the FSAR.

3. The data were good enough to show a correlation between the high and low pressure runs on the Loop A accumulator such that the discharge pipe resistance factors calculated from each run agreed within about 20%, the major part of which isprobably due to errors in reading the recorder charts.

4. Between the two low pressure runs, (Loop A vs. Loop B), the variations in calculated resistance factor was about as predicted by the piping resistance calculations used as input to the analysis in the FSAR.

   Table I shows numerical results in support of the above conclusion.

   The long blowdown of the Loop B high-pressure run was cause for concern since it appeared that a substantial

resistance, about three times normal, had suddenly been introduced in the line.

A review of piping resistance calculations and layout drawings was made without uncovering any reason for the long blowdown during that specific run.

Items investigated were as follows:

Possibility: <u>The initial gas pressure was low</u>

This was ruled out since two pressure indicators showed 720 psi before start of the test and because the quantity of N_2 was metered into the tank and observed to be the same as a subsequent Loop A high pressure run.

Possibility: <u>The chart speed was inadvertently increased</u>

Ruled out due to corresponding times of transient between chart and stop watch.

Possibility: <u>An obstruction in the line</u>

Ruled out due to disassembly of vlaves, observations by borescope and by swabbing of the line segments which could not be observed.

Possibility: <u>Stuck check valve</u>

Ruled out due to obvious free movement and seat tightness of valves when observed on disassembly. If the valves had been subjected to nearly 700 psi differential some evidence in valve damage might have been noted.

Possibility: Jammed M.O. Valve

Inspection showed no sign of mechanical damage or of loss of freedom of movement. No foreign matter was in the valve.

With the rest of the Loop B accumulator flow path shown clean and free flowing and with one low pressure run which corresponds well with the line resistance and performance of the Loop A unit, attention was turned to the possibility that the MOV started, but did not complete its stroke.

This appears to be the most likely reason for the anomalous run at high pressure on Loop B.

1. The Loop A and Loop B runs are practically identical up to about 4 seconds into the transient when Loop B data show establishment of a constant resistance (about 1275 L/D). From that point until the termination of blowdown, the pressure transient is predictable for an unchanging resistance.
2. The mark automatically put on the chart with the contacting of the valve open limit switch is missing from only this run.
3. There was no direct observation that the valve did open, although it was operationally tested over its full stroke

after the test without any difference in pressure across the disc.

4. Two operators have testified that the monitor lights did not change to indicate picking up the full-open limit switch on this run. The weight of evidence which we have collected leads to the judgement that:

   (a) The accumulator lines are clean and should function with a fully open isolation valve in a manner that is entirely consistant with the commitments made in the FSAR.

   (b) The motor operated isolation valve started but did not complete its stroke.

Since this motor operated valve is normally open and is not required to function during an accident, it should not be considered as an impediment to the safety of the plant. Test recordings are on file at Ginna.

C. <u>Safety Injection Flow Test</u>

Section 11.0 of RG&E S.U.-4.5.1 was revised and treated as an individual test titled, "Safety Injection Flow Test." This revised test tested in greater detail the equipment involved than did the original. The purpose of the test was to:

1. Verify the safety injection pumps shutoff head.
2. Verify the safety injection pumps pressure and flow characteristics.
3. Verify the residual heat removal pumps pressure and flow characteristics to the reactor coolant system.
4. Demonstrate the residual heat removal pumps recirculation to all three safety injection pumps.
5. Demonstrate the residual heat removal pump "A" recirculation to the "C" safety injection pump.

The shutoff head of the safety injection pumps and the residual heat removal pumps is 1520 psi and 141 psi, respectively. The design pressure and flow is 1080 psig at a flow of 300 gpm for the safety injection pumps and 121 psi at a flow of 1560 gpm for the residual heat removal pumps. The test demonstrated that the design flow characteristics of all five pumps were realistic and proven exceeded in practice. Trace recordings of pressure and flow were made during the test runs and are on file.

The ability of the two residual heat removal pumps to deliver to the three safety injection pumps was demonstrated and the various flows and pressures of interest were recorded. The ability of the "A" residual heat removal pump to deliver to the "C" safety injection pump was satisfactorily demonstrated with the flows and pressures of interest recorded.

D. Containment Spray System

The shutoff head of the containment spray pumps was tested as a part of RG&E S.U.-4.5.1 and found to be higher than the shutoff head on the design curve. The FSAR lists the design head and flow of the spray pumps as being 189 psi and 1615 gpm. Since there is no way to test design flow and head without flooding the containment building, pump performance was evaluated by comparing the pump flow and head at recirculation flow (45 gpm) to the design head curve. This tested satisfactorily. The valve operation and sequencing of this system was tested satisfactorily in the "safety injection functional test."
The remainder of the piping from the last valve to the nozzles in the spray ring headers was tested by charging the piping with compressed air and suspending a helium filled balloon with tell tails in front of each and every nozzle. Each nozzle opening was proven free and clear.

E. Residual Heat Removal System

The purpose of the residual heat removal test was to verify that the system components were capable of meeting their design requirements and that the system interlocks and interlocks to other systems operate as intended. The capability of the residual heat removal pumps to meet design requirements was

successfully demonstrated in the safety injection test RG&E S.U.-4.5.1. A functional test of the interlocks involved in the residual heat removal system was performed as outlined in RG&E S.U.-4.3.2. All interlocks are presently operating as required.

Testing of the residual heat exchangers to insure that their heat exchanging capabilities met specifications was performed during a cool-down period. Test results demonstrated that the specifications for these exchangers were conservative.

To insure that the recirculation phase of safety injection could be performed, a recirculation functional test was written and successfully completed demonstrating valve operation and flow from sump "B" through the residual heat removal pumps.

F. Safeguards Systems Operational Test

The intention of this test procedure, RG&E S.U.-9.8.2, was to insure that all safeguards systems were operationally checked out before criticality. This checkout involved a test of individual channel tripping followed by logic trains "A" and "B" tripping where applicable. Safeguards systems valves and motors were not actuated for this test since actuation of these components had been performed in other tests, but rather the actuating devices of the components such as relays, controllers,

etc., were monitored for operation. Verification of proper operation of alarms and indicating lights was a part of this test procedure. The following is a list of the safeguards systems that underwent the operational checkout in this test:

1. Steam Line Isolation
2. Safety injection and initiation of the following safeguard action subsequent to initiation of safety injection:
   (a) Feedwater System Isolation
   (b) Reactor Trip
   (c) Emergency Diesel Starting
   (d) Auxiliary Feedwater Pump Starting
   (e) Fan Cooling Starting
   (f) Service Water Pump Starting and System Isolation
3. Containment Spray
4. Containment Isolation
5. Containment Ventilation Isolation

G. <u>Emergency Diesel Generator Test</u>

This test was performed to see that the two diesels and auxiliary equipment will perform their designed functions when required to do so.

The first part of the test was concerned with the capacity of the air storage tanks and their ability to crank the diesels for 45 seconds. Although they were incapable at first, one

additional air storage tank was added to each diesel starting air supply thus doubling the air storage capacity. A second test was performed which proved that the air starting system was capable of cranking the diesels for 45 seconds.

It was also necessary to test the starting signals for both diesels. Where signals can come from redundant sources these sources were checked individually. All start signals performed according to design.

The undervoltage relay circuits are designed to clear a bus of almost all equipment if there is an undervoltage condition on that bus. Thus, the diesel will not be connected to a fully loaded bus and probably trip the diesel on overcurrent because of the high starting current required. Each redundant undervoltage relay circuit was tested for the 480V safeguard busses and performed to clear the bus involved and also to start the appropriate diesel.

The diesel itself was tested to insure that it was capable of starting and that the control circuitry could place it on line in ten seconds. Load tests were run and showed that the diesels were capable of their rated capacity, and could satisfactorily carry their safeguard load during steady state and safeguard sequencing load pickup.

During the test, the sequencing relays for safeguard equipment starting were set and will now start equipment within .3 seconds of the design times. Safeguard valves not covered by the Safety Injection Test were tested to insure that they would close oropen as required on safeguard initiation.

In Addition, control and alarm and tripping circuitry was tested to insure that these functions were properly performed.

Although not directly involved, it was felt that all interlocks on the following breakers should be tested to insure proper operation: 52/EG1A1, 52/EG1A2, 52/EG1B1, 52/EG1B2, 52/14, 52/16, 52/17, 52/18, 52/BT16-14, and 52/BT17-18. Because of this testing, one design change was made and a couple of wiring mistakes were corrected. Once the changes were completed, the tests on these breakers were performed satisfactorily.

H. D.C. Battery Test

Each battery system was tested in two basic ways.

First, the battery charger voltage outputs for varying loads and varying charger input voltages were tested. It was found that although the 480 volt A.C. input voltage was varied by 10%, the D.C. output voltage of the chargers did not vary by more than 1% under varying load conditions.

TABLE I

RESULTS

1. Observed Results

	Low Pressure		High Pressure	
Loop	A	B	A	B
Initial level (%)	40	40	40	40
Initial gas vol. (ft^3)	750	750	750	750
Initial pressure, psig	300	300	740	720
Valve opening time (sec)	10	9.7	10	?
Delay before fluid enters vessel (sec)	---	---	4.5	4.5
Liquid blowdown time - total (sec)	---	---	29	54
Gas blowdown time (sec)	---	---	30	50
Water lost to loop seal (gal)	640	875	1110	1125

2. Example — Prediction of Final Pressure

Run -	Loop A -	Initial Pressure	740 psig
		Initial Gas Volume	750 ft^3
		Final Gas Volume	1750 ft^3
	Final Pressure:	Calculated ($pv^\gamma = C$)	220 psig
		Measured - PT - 936	200 psig
		PT - 937	220 psig

3. Data Analysis - Pipe Resistance

Loop	Initial Press psig	Computer Sheet (Attach. -3)	Pipe Resistance Equiv. Dia. (L/D)	
A	740	1	305	Same Run
A	740	2	334	
A	300	3	371	
B	300	4	388	
B	740	5	1275	

Resistance used in FSAR analysis 530

"A" LO

CONTAINMENT VESSEL

Valve Number	BEFORE TRIP: Valve Position		Status Lights		Indicator Lights		AFTER TRIP: Valve Position		Status Lights		Indicator Lights	
	Open	Close	Dim	Bri	Red	Green	Open	Close	Dim	Bri	Red	Green
878 A		X	X			X	X			X	X	
878 B		X	X			X		X	X			X
878 C		X	X			X	X			X	X	
878 D		X	X			X		X	X			X
852 A		X	X			X	X			X	X	
852 B		X	X			X		X	X			X
COV -1B	X		X					X		X		
5870 PSV-1	X		X		X			X		X		X
5879 PSV-0	X		X		X			X		X		X
AOV 951	X		X		X			X		X		X
953	X		X		X			X		X		X
955	X		X		X			X		X		X
841		X	X			X	X			X	X	
865		X	X			X		X	X			X
BV 1-I		X					X					
BV 1-K		X					X					
BV 1-F		X						X				
BV 1-L		X					X					
BV 1-J		X					X					
BV 1-H		X						X				
851 A		X	X			X			X			X
851 B		X	X			X			X			X

"B" I IC

CONTAINMENT VESSEL

Valve Number	BEFORE TRIP: Valve Position		Status Lights		Indicator Lights			AFTER TRIP: Valve Position		Status Lights		Indicator Lights	
	Open	Close	Dim	Bri	Red	Green		Open	Close	Dim	Bri	Red	Green
878 A		X	X			X			X	X			X
878 B		X	X			X		X			X	X	
878 C		X	X			X			X	X			X
878 D		X	X			X		X			X	X	
852 A		X	X			X			X	X			X
852 B		X	X			X		X			X		
COV 1B	X		X						X		X		
5870	X		X		X				X		X		X
5879	X		X		X				X		X		X
AOV 951	X		X		X				X		X		X
953	X		X		X				X		X		X
955	X		X		X				X		X		X
841		X	X			X			X	X			X
865		X	X			X		X			X	X	
851 A		X	X			X				X			X
851 B		X	X			X				X			X
BV-1-I		X						X					
BV-1-K		X						X					
BV-1-F		X							X				
BV-1-L		X						X					
BV-1-J		X						X					
BV-1-H		X							X				

The second basic test was designed to show that the battery itself could sustain a discharge rate of 131 amps for eight hours while not lowering the output voltage below 105 volts. Although neither battery passed in the first test, each passed after a number of cells in each battery were replaced.

II. Pre-operational Instrumentation and Control Tests

A. Reactor Coolant System Pressure Comparison Test RG&E S.U.-4.6.16

The purpose of this test was to verify the calibration of the primary coolant system pressure instrumentation at various actual system pressures. The test was performed while heating up the system to no load temperature and pressure conditions. At various pressure levels the pressure instrumentation of the reactor coolant system was checked against the reading of a deadweight tester nulled across a dp cell to the actual system pressure. This test was completed successfully on June 28, 1969.

B. RTD Cross Calibration Test - RG&E S.U.-4.1.14

This test procedure was used to determine isothermal corrections for reactor coolant RTD's and incore thermocouples.

The reactor coolant temperature was maintained at a constant shutdown temperature of 545 degrees F. Resistance measurements of the 10 RTD's of the A reactor coolant loop were taken

three different times with a precision ohmmeter and averaged. The temperature of each RTD was then calculated. The same procedure was followed for determining the temperature of the "B" loop. Averaging the temperatures of the RTD's in the A loop resulted in a temperature of 545.5 degrees F while that of the "B" loop resulted in a temperature of 545.5 degrees F. Incore thermocouple maps were obtained by computer print-out while the RTD measurements were being taken with good agreement to RTD measurements.

C. <u>Steam Generator Manual Control and Level Instrumentation Test - RG&E S.U.-4.15.1</u>

In essence, this test was a functional test of the steam generators, condensate system, feedwater system, auxiliary feedwater system, and the instrumentation of these systems.

Analog simulators were used to inject signals into steam generator level channels. These signals were varied to allow verification of bistable setpoints and calibration of the level indicators. The functions that were verified and their respective setpoints are as follows:

Lo-Lo Water Level Single Channel Alert - 15%

Lo-Lo Water Level Reactor Trip - 15%

Steam Generator Level Setpoint Deviation - $\pm$ 5%

Steam Generator High Level Loop A/B Channel Alert Alarm - 68%

Steam Generator High Level Alarm - 68%

Feedwater Valves Close - 68%

Feedwater Bypass Valves Open - 10%

Steam flow and feedwater flow indicators were calibrated by simulating signals to the indicators. The steam flow feedwater flow mismatch circuits were adjusted to give Lo Feedwater Flow Single Channel Alert Alarm and Reactor Trip at a $.7 \times 10^6$ #/hr of steam flow in excess of feedwater flow deviation. Steam Generator Hi Feedwater Flow alarms were set for a deviation of $.7 \times 10^6$ #/hr of feedwater flow in excess of steam flow.

Pressure signals were simulated to the steam generator pressure channels to calibrate the pressure indicators and set the pressure related bistables. The Lo Steam Pressure Loop A/B alarms and channel status lights were set for 600 psig. Steam Line Lo-Lo Pressure Loop A/B Channel Alert were set for 500 psig.

The turbine first stage pressure indications and alarm checkout was performed by simulating a pressure signal. The channel status trip setpoint was set at 45.5 psig for the two turbine first stage pressure channels.

The test required the stroking of all valves in the condensate, feedwater, and auxiliary feedwater systems with final position of the valves in the normal operating position. The condensate and feedwater pumps were started and flow measurements versus feedwater bypass valve position were taken.

The automatic start of the auxiliary feedwater pumps was verified by tripping the main feedwater pumps.

D. <u>Rod Position Indication System - RG&E S.U.-4.11</u>

Verification of the satisfactory performance of the rod position indicating system for each control rod and each control rod bank under hot shutdown conditions was demonstrated in this test. Voltage readings were taken and recorded at the output of each LVDT at various intervals of rod travel for each rod. Associated alarms were verified and the bank overlap of each bank was set at 195 steps for rod withdrawal and 35 steps for rod insertion.

E. <u>Rod Stepping Test - RG&E S.U.-4.10.1</u>

This test was designed to verify that the Rod Control Systems satisfactorily perform the required stepping operations for each individual rod under both hot and cold conditions.

Each rod was fully withdrawn and fully inserted while recordings were made of current flows to the various rod drive mechanism coils. These recordings are on file at Ginna Station.

F. RCCA Drop Time and Partial Length Rods Operational Tests RG&E S.U.-4.10.2

The purpose of this test was to determine the drop time of each full length RCCA under a number of reactor coolant system operating conditions. The data sheets following are samples of the data sheets used for this test noting operating condition of the system and the rod drop times. Originally, the Ginna Technical Specifications gave a maximum rod drop time of 2.7 seconds based on earlier PWR desgin and experience. These specifications were modified to take into consideration the longer control rods of the Ginna Plant. The specifications now read that the maximum elapsed time to the dash pot shall not exceed 1.8 seconds and shall not exceed 5 seconds to bottom out.

A second purpose of this test was to functionally check the partial length control rod drive system to determine proper indication of rod position and the operational characteristics of the system when the 440 volt power is interrupted. The results of the test are typified in the data sheets of Figures II-1 through II-5.

G. Incore Thermocouples - RG&E S.U.-4.13.1

The purpose of this test was to provide a functional checkout and demonstration of the incore thermocouple and readout

system at hot shutdown conditions. The reactor coolant system was maintained at a constant temperature of 549°F for the duration of this test. Analog readings were taken and recorded for each of the incore thermocouples. A computer readout was also obtained for each of the incore thermocouples. The reactor coolant system RTD readings were taken at the time and compared to the analog and computer incore readings. The results of this test were satisfactory.

H. Movable Incore Detector System Test - RG&E S.U.-4.13.2

This test provided a functional demonstration of the incore flux mapping system.

Each of the four detectors were operated simultaneously and then separately in all possible modes of scan. Limit switches were set, associated alarms were verified, scan rates were set, and position readouts and indicating lights were verified. The test results were satisfactory with only minor discrepancies which have since been corrected.

I. Reactor Makeup Blender and Boric Acid Transfer Pumps Operational Test - RG&E S.U.-4.2.7

The purposes of this test were:

1. Obtain information of the operational characteristics of the Reactor Makeup Blender in the "automatic makeup", "Borate", and "dilute" modes of operation.

2. Provide a measure of the mixing characteristics of the reactor coolant system.

3. Determine the temperature rise in the boric acid tanks caused by the energy input into the system from the boric acid transfer pumps operating continuously in the recirculate mode.

Various amounts of reactor makeup water were dialed into the Veeter-Root Integrater at different times and the blender system was energized. When the amount of reactor makeup integrated equaled the amount dialed, the "blend" system de-energized automatically. The amount of water delivered to the reactor coolant system was measured by calculating the displacement in the volume control tank. This was compared to the amount that had been set for and the amount integrated by the Veeter-Root Integrater.

The "borate" mode was checked in the same manner with the exception that the boric acid was collected in calibrated containers at a sample point.

The flow rates of the "borate" and "dilute" modes were confirmed to agree with the rates set by the controller.

The "automatic makeup" mode of operation was checked for performance by injecting different concentrations of boric acid blend into the reactor coolant system and sampling the

coolant at various time intervals at different sample points of the reactor coolant system.

Recirculating the boric acid storage tanks with the boric acid transfer pumps raised the temperature of the number one tank 14°F in 8 hours and 55 minutes and the number 2 tank 15°F in 7 hours and 55 minutes. The number 1 tank cooled 7 1/2°F in 22 hours and the number 2 tank cooled 9°F in 22 hours. The test was completed with satisfactory results.

J. <u>Pressurizer Level Control Test - RG&E S.U.-4.2.3</u>

The objective of the pressurizer level control test procedure was to verify that the pressurizer level control system setpoints were properly set and that the control system functions properly.

With the reactor coolant system at the no-load temperature (547°F), and pressure (2235 psig), condition, and with all pressurizer controls in the automatic mode of operation, all pressurizer level indicators were checked and level indications recorded. Proper operations of channels was verified in this manner.

Preliminary values for the proportional band, rate time constant, and reset time constant for pressurizer level controller LC-428 F were given in the RG&E Reactor Control and Protection System Precautions, Limitations, and Setpoints

Operating Instruction, P-1. These preliminary values were used during the initial checkout and calibration of the controller.

To determine how well the control system responded to system level and Ave Tave variations, first the manual control setpoint on TC-401C (remote setpoint controller for LC-428C was varied from 547°F to 540°F. This simulates a rise in Ave Tave. A rise in the pressurizer level followed. The level was lowered to the original value by reversing the above procedure. The levels on all level channels were recorded.

The level control system of the pressurizer was next checked by increasing the level of the pressurizer by manually controlling the charging line flow control valve HCV-142 and the charging pumps. As the pressurizer level increased it was verified that the pressurizer high level alarm occurred at 70%, pressurizer heaters were energized at 70% and pressurizer high level reactor trip partial matrix alarm occurred at 92%.

The level was reduced in the pressurizer by the manual method described above and it was verified that pressurizer low level alarm occurred at 5% below the level program setpoint, the low level alarm, letdown isolation, (LCV-427 closed), and heaters turned off at 11%, and a safety injection partial matrix alarm occurred at a level of 5%.

This test was successfully completed after the second attempt.

NOTE: The pressurizer level program setpoint is a function of Tave and varies from 19.5% at 547°F to 49% at 570°F.

K. <u>Pressurizer Pressure Control - RG&E S.U.-4.1.3</u>

The objective of this test was to first check the response, stability, and general control characteristics of the pressurizer pressure control system and make any adjustments to the controllers required to obtain proper operation, and secondly, to verify that all the various alarms and control setpoints are properly set and function as required.

With the reactor coolant system at the no-load temperature, and pressure conditions and pressurizer pressure controls on automatic, the proper operation of all pressurizer pressure indicators and recorders was verified. The control board pressure control controller was placed in the manual position and its signal varied to verify the following setpoints:

Proportional heaters full off at 2250 psig.

Proportional sprays begin at 2260 psig.

High pressure alarm at 2310 psig.

Relief valve PCV-431C opens at 2330 psig.

The reactor coolant system pressure was actually changed to verify the following:

Relief valve PCV-430 opened at 2335 psig.

High pressure reactor trip at 2400 psig.

With pressurizer heaters on automatic, the reactor coolant pressure was reduced by manually controlling spray water to the pressurizer. The following setpoints were verified during this mode of operation:

Proportional heaters full on at 2220 psig.

Backup heaters on at 2210 psig.

Power relief valve interlock functioned at 2185 psig.

Pressurizer low pressure alarm at 2185 psig.

Safety injection could be manually blocked below 2000 psig.

Low pressure reactor trip partial matrix alarm at 1720 psig.

Safety injection partial matrix alarm at 1715 psig.

The pressurizer heaters had been turned off after verifying their operation points. They were then turned back on and put in the automatic mode after completing the pressure decrease portion of the test. This resulted in a gradual pressure increase allowing the following setpoint to be verified:

Low pressure reactor trip partial matrix alarm cleared at 1725 psig.

Safety injection unblocked at 1990 psig.

Power operated relief valve interlock functioned at 2190 psig.

L. Steam Dump - RG&E S.U.-4.9.2

The purpose of this test was to optimize the settings of the steam dump controller and to functionally test the system.

Some portions of this test could not be performed since steam dump to the condenser could not be sustained for any period of time without nuclear heat. Those portions omitted in this test were performed in the operational transient tests.

A simulated signal was fed into the steam bypass controller. This signal was varied until the turbine trip interlock was satisfied and the steam dump to the condenser valves opened. The test signal was decreased until the turbine trip interlock cleared and the steam dump valves to the condenser modulated close. Four of the eight condenser valves were set to open with the simulated signal for Tave at 8°, and the other four were set to open at 16°F. This procedure was repeated for the other condenser steam bypass controller with the exception that four of the valves were set to open at 12°F and the remaining four at 20°F.

The atmospheric steam dump system was functionally tested at this time for controller response and secondary system pressure control capabilities.

This system tested satisfactorily.

M. <u>Radiation Monitoring System Operational Test</u>

<u>RG&E S.U.-4.7</u>

The purpose of this test was to provide an operational test of the complete Radiation Monitoring System to ensure that it will perform all the functions that are required of the system.

Figures II-6 and II-7 are typical data sheets of the test results of one of the Radiation Monitoring System channels. The data explains the test objectives. The results of this test were acceptable to the Rochester Gas and Electric Corporation.

N. <u>Reactor Coolant System Flow Measurement Test</u>

<u>RG&E S.U.-4.15.1</u>

The purpose of this procedure was to provide a means of obtaining the necessary data to interrelate pump input power, elbow tap and steam generator delta P as an accurate measurement of flow rate. A description of the methods used to interrelate these paramenters is contained in pages 4.2.19 through 4.2.24 of the FSAR.

Having completed this test, the preliminary data analysis has been completed and indicates the reactor coolant system flow rate for loop A to be 95,200 gpm or 106% of design flow, and for loop B to be 94,000 gpm or 104.8% of design flow. A detailed analysis is presently nearing completion.

O. Nuclear Instrumentation - RG&E S.U.-4.8

This test provided a functional demonstration of the Nuclear Instrumentation System. Each of the 12 drawers (one for each nuclear instrumentation channel) was functionally operated and calibrated by simulating a detector signal to the first element after the detector in a channel. All trips and permissive signal setpoints generated by the NIS system were set, associated alarms were verified, and all remote meters and recorders were checked for proper operation and indication. The test results were satisfactory.

Data Sheets

Paragraphs are keyed to test procedure

5.2 Control Rod Drop Test - Cold (Ambient) No Flow Condition

Date: Oct. 20, 1969

RCCA BANK NO.	RCCA GRID LOCATION	DROP TIME TO DASH POT (t_1) (sec)	DASH POT TO ROD BOT. TIME (t_2) (sec)	TOTAL DROP TIME ($t_1 + t_2$) (sec)	RCS Tavg (°F)	RCS FLOW (%)	RCS PRESSURE (psig)
S	E3	1.03	1.36	2.39		0	300
	C9	1.12	1.32	2.44			
	I11	.99	.33	2.32			
	K5	1.03	1.33	2.36			
	I3	1.01	1.30	2.31			
	C5	1.03	1.28	2.31			
	E11	1.01	1.34	2.35			
	K9	1.02	1.34	2.36			
A	F2	1.00	1.31	2.31			
	B8	1.00	1.34	2.34			
	H12	.99	1.35	2.34			
	L6	1.10	1.30	2.40	90	0	300
	H2	1.03	1.32	2.35			
	B6	1.06	1.35	2.41			
	F12	1.06	1.30	2.36			
	L8	1.11	1.28	2.39			
B	I7	1.11	1.35	2.46			
	E7	1.13	1.30	2.43			
	G5	1.11	1.32	2.43			
	G9	1.11	1.32	2.43			
C	D4	1.01	1.35	2.36			
	G7	1.03	1.33	2.36			
	J10	1.01	1.38	2.39			
	J4	1.10	1.35	2.45	90	0	300
	D10	1.10	1.41	2.51			
D	K7	1.07	1.30	2.37		0	
	C7	1.11	1.23	2.34			
	G3	1.10	1.29	2.39			
	G11	1.10	1.35	2.45			

Figure II-1

5:3 Control Rod Drop Test - Cold ($200^{o}F \leq$ Tave $\leq 300^{o}F$) - Full Flow Condition

Date: 20 Oct. 69

RCCA BANK NO.	RCCA GRID LOCATION	DROP TIME TO DASH POT (t_1) (sec)	DASH POT TO ROD BOT. TIME (t_2) (sec)	TOTAL DROP TIME ($t_1 + t_2$) (sec)	RCS Tavg (^{o}F)	RCS FLOW (%)	RCS PRESSURE (psig)
C	D-4	1.01	1.35	2.36			
C	G-7	1.03	1.33	2.36			
C	J-10	1.01	1.38	2.39			
D	G-3	1.10	1.29	2.39			

Drop Time Limit 2.70 sec.

Avg Drop Time 2.39 sec. 2.383 sec.

Max. Drop Time 2.51 sec. (2.39 + .13)

Min. Drop Time 2.31 sec. (2.39 - .07)

Avg$\{|$drop time - avg drop time$|\}$ = .04 sec.

Figure II-2

5.3A 10 Hot Full Drop Test No Flow

Run	Drop Time to Dash Pot (t_1 sec.)	Dash Pot to Seat (t_2 sec.)	Total Drop Time ($t_1 + t_2$) (sec.)	RCS Tavg (°F)	RCS Pressure (psig)
G-3 NO FLOW					
1	1.04	.99	2.03	520	2240
2	1.05	.96	2.01	519	2240
3	1.04	.99	2.03	519	2240
4	1.04	.99	2.03	518	2240
5	1.05	.98	2.03	515	2240
6	1.05	.98	2.03	514	2240
7	1.05	.99	2.04	512	2240
8	1.04	.98	2.02	511	2240
9	1.05	.99	2.04	510	2240
10	1.06	.99	2.05	510	2240
G-7 NO FLOW					
1	1.05	.98	2.03	539	2235
2	1.05	.98	2.03	535	2245
3	1.06	.99	2.04	535	2240
4	1.05	1.00	2.05	535	2235
5	1.05	1.01	2.06	530	2240
6	1.05	1.00	2.05	530	2240
7	1.04	1.02	2.06	529	2240
8	1.06	1.00	2.06	528	2240
9	1.05	1.02	2.07	525	2240
10	1.05	1.00	2.05	524	2240

Figure II-3

5.3A 10 Hot Full Drop Test Full Flow

Run	Drop Time to Dash Pot (t_1 sec.)	Dash Pot to Seat (t_2 sec.)	Total Drop Time ($t_1 + t_2$) (sec.)	RCS Tavg (°F)	RCS Pressure (psig)
G-3 WITH FULL FLOW					
1	1.23	1.16	2.39	542	2240
2	1.25	1.13	2.38	544	2238
3	1.25	1.13	2.38	546	2233
4	1.25	1.13	2.38	544	2230
5	1.23	1.14	2.37	550	2230
6	1.24	1.12	2.36	550	2230
7	1.24	1.12	2.36	551	2230
8	1.23	1.13	2.36	553	2245
9	1.24	1.10	2.34	554	2230
10	1.23	1.11	2.34	552	2100
G-7 WITH FULL FLOW					
1	1.23	1.17	2.40	551	2135
2	1.24	1.16	2.40	551	2160
3	1.24	1.17	2.41	552	2200
4	1.24	1.15	2.39	554	2255
5	1.25	1.15	2.40	554	2235
6	1.24	1.22	2.45	555	2233
7	1.23	1.19	2.47	554	2233
8	1.25	1.15	2.40	554	2220
9	1.23	1.17	2.40	554	2200
10	1.24	1.18	2.41	555	2222

Figure II-4

5.7 Partial Length CRDM Checkout:

RCT T_{avg}: > 500 °F RCS Flow: 100 %

5.7.1 Partial Length Rod Total Travel Test:

	Partial Length Rod Grid Location			
	E-5	E-9	I-5	I-9
LVDT Reading at Bottom "Dead" Stop	0	0	0	0
LVDT Reading at Top Dead Stop	144	144	144	144
Whittaker Counter Reading at Bottom Dead Stop	0	0	0	0
Whittaker Counter Reading at Top Dead Stop	230	230	230	230
Time-Bottom Dead Stop to Top Dead Stop	9 min 34 sec.	9 min 34 sec.	9 min 34 sec.	9 min 34 sec.

Figure II-5

CHANNEL R- 12 DATA SHEET

1. Calibration Source:

Type	Cs^{137}
Strength	1.85×10^5 DPM

2. Detector High Voltage Determination:

Final High Voltage Setpoint	950 Volts
Final Log Rate Meter Reading	500 CPM

3. Log Rate Meter Background Count Rate: 70 CPM

4. Channel Functional Test:

Log Rate Meter Reading	220 CPM
High Level Alarm Check	Sat.
Annunciator Check (Alarm and Channel Test)	Sat.

Automatic Actions:

1) Cont. Pressure Relief Valves (7970 & 7971) Close :________

2) Cont. Purge Supply Valves (5869 PSVI & 5870 PSVO) Close : 1.68Sec/1.48 Sec

3) Cont. Purge Exhaust Valves (5878 PEVI & 5879 PEVO) Close : 1.54Sec/1.66 Sec

5. Bistable Trip "Reset" Check: Sat.

Background Count Rate Check: 70 CPM

6. Log Rate Meter "Test" Check:

Log Rate Meter Count Rate	60K CPM
Computer Output Voltage	3.72 Volts

7. "Low Level" Alarm Check: Sat.

8. "Low Level" Alarm Reset Check: Sat.

Figure II-6

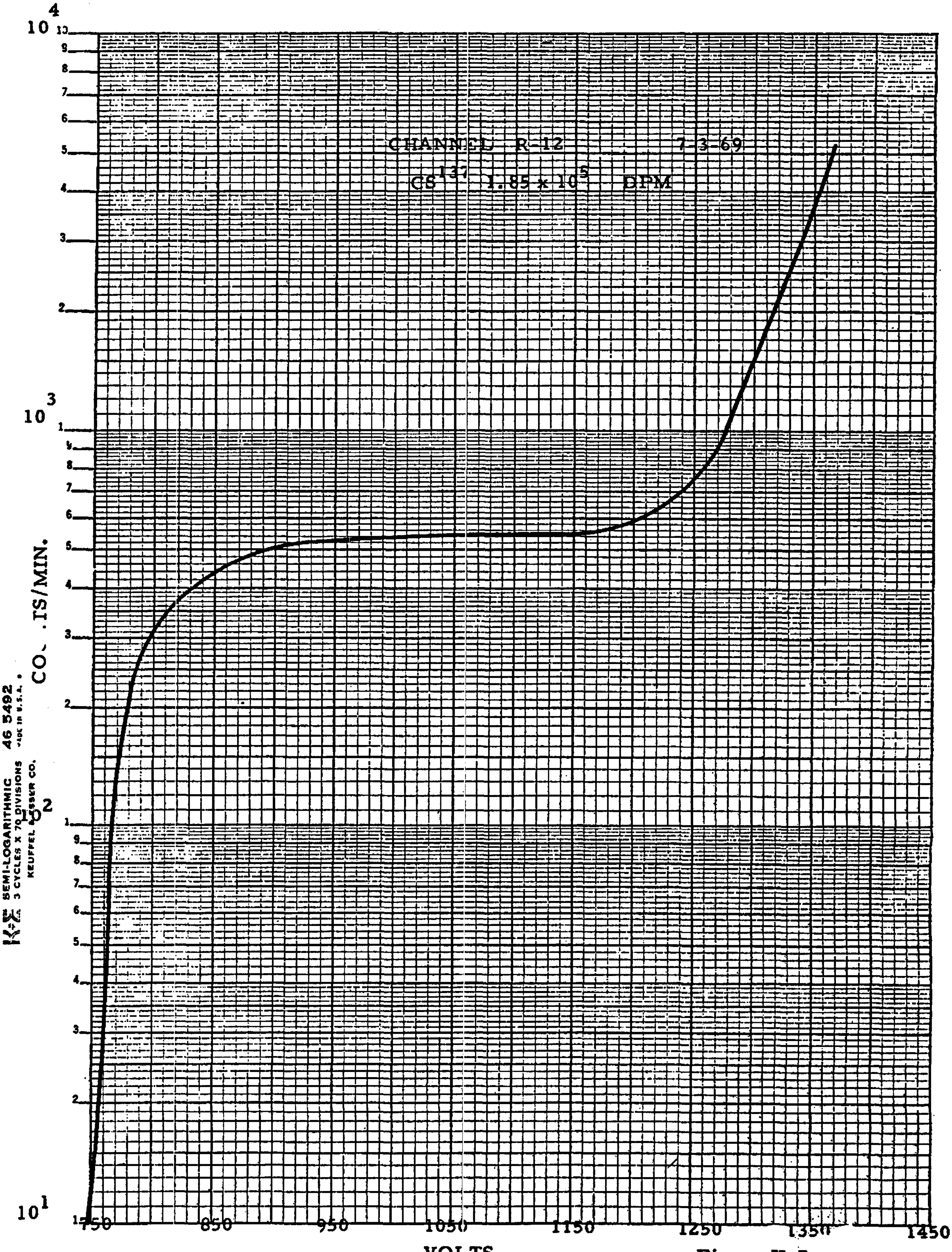

CHANNEL R-12 7-3-69
CS 137 1.85 x 10 5 DPM
CO. .TS/MIN.
VOLTS
750
850
950
1050
1150
1250
1350
1450
10 4
10 3
10 2
10 1
K+E SEMI-LOGARITHMIC 46 5492
3 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO.

Figure II-7

III. Safety and Relief Valve Tests

A. Pressurizer Safety Valve Test RG&E S. U. - 4.1.4

The above named test was performed to verify the proper setting of the pressurizer safety valves.

To perform this test the system pressure was maintained between 1865 psig and 2110 psig. A Crosby Valve Company air set lifting device was installed on PCV-434 (pressurizer safety valve) bonnet and an air supply attached to the device. By controlling the pressure regulator manually, the pressure was gradually increased to the lifting device. Pressurizer pressure readings and air pressure readings to the lifting device were taken continuously during this procedure. When the pressurizer valve began to open, simmer, or leak audibly, the air pressure on the lifting device was released. A differential pressure was determined from a curve for K2 oriface in Crosby Valve Company Instruction No. T-1652-1 for the air pressure reading of the air supply to the lifting device when the valve first opened. This differential pressure was added to the pressurizer pressure reading at valve opening to determine the actual pressure at which the valve would open. This test was repeated until the valve opened at 2485 psig $\pm$ 1%. Figure III - 1 is a copy of the data sheet for the testing of both pressurizer safety valves.

B. Main Steam Safety Valve Test RG&E S. U. - 4.32.2

The setting of the main steam safety valves was accomplished in the same manner as was the setting of the pressurizer safety valves, however the differential pressure was obtained from the curve for R oriface in Crosby Valve Company Instruction book T-1652-1 of air pressure versus differential pressure.

The set pressures for each of the main steam relief valves is as follows:

V-3508	1141 psig
V-3509	1130 psig
V-3510	1140 psig
V-3511	1140 psig
V-3512	1140 psig
V-3513	1138 psig
V-3514	1085 psig
V-3515	1078 psig

The requirements were to set V-3515 and V-3514 at 1085 psig ± 1% and V-3508 - V-3513 to 1140 psig ± 1%.

Original Issue 4-2-69

DATA SHEET

RGE-SU-4.1.4

Paragraphs are keyed to test procedure.

5.1 Communications established YES.

Valve PCV 434 (Set pressure 2485 psig ± 1%)

5.2 Lifting device installed CROSBY.

5.3 Pressure control point ______ psig.

		Test 1	Test 2 (3 Times)	Test 3	Test 4
	66 lbs. change per 1 flat				
5.5 &	Pressurizer Pressure	2000 psig	1887 psig	1945 psig	1945 psig
5.6	Air Pressure	39 psig	30 psig	42 psig	41 psig
5.7	Differential Pressure (from curve)	520	400	557	545
	Pressurizer Pressure	2520	2287	2502	2490

Sum = Set Pressure

Valve PCV 435 (Set Pressure 2485 ± 1%)

5.2 Lifting device installed ______.

5.3 Pressure Control Point ______ psig.

		Test 1 3 Times	Test 2 2 Times	Test 3 2 Times
5.5 &	Pressurizer Pressure	2046 psig	2065 psig	2065 psig
5.6	Air Pressure	32 psig	31 psig	32 psig
5.7	Differential Pressure (from curve)	425	410	425
	Pressurizer Pressure	2471	2475	2490

Sum = Set Pressure

FIG. III-1

IV. Waste Systems Tests

A. Liquid Waste Concentration Demonstration Test. RG&E S.U. 4.6.4

The purpose of this test was to demonstrate the proper operation of the two major drumming processes.

Section 5.0 demonstrates the process of drumming concentrated waste from the waste evaporator feed tank. This includes the operation of the recirculation system from the evaporator feed tank to the dispensing header, and the vacuum operated dispensing valves and vacuum switches. The test also included the testing of the use of the drums, shields, vacuum pump, and the manipulating tools.

The test had been successfully run with water and since, has been used frequently with waste concentrates with no major problems.

Section 6.0 of this test demonstrates the process of sluicing spent resins from the storage tanks to the drums. The operation of the pressurization and agitation systems along with the instrumentation associated with these systems was functionally checked. The proper operation of the dispensing valves, drums, shields, vacuum pump and manipulating tools for this mode of operation was demonstrated.

B. Waste Disposal System Gaseous Waste Test. RG&E S. U. 4. 6. 3

This test was a functional test of the waste gas system to ensure that the system could adequately process or vent the gaseous waste emanating from the vent header. All alarms and instrumentation associated with the system were verified for porper operation as were all automatic functions. The waste gas system had since been operated under its intended normal radioactive conditions with satisfactory performance.

C. Liquid Waste Processing. RG&E S. U. 4. 6. 2

The purpose of this test was to functionally test portions of the waste disposal system including the waste evaporator, and to demonstrate that the liquid waste disposal system can adequately dispose of the liquid waste products in a safe and reliable manner.

The test was run with satisfactory results with one exception. The DF across the waste evaporator deteriorated with rated flow of 2 gpm. A DF of 10^6 could be maintained with a flow rate of 1. 5 gpm. Westinghouse is presently rewriting this test. This system has not been accepted by the RG&E as of this date, although presently in service at the lower flow rate.

V. Reactor Coolant System Measurement Tests.

A. Reactor Vessel Internals Measurement Test. RG&E S. U. 4.1.7

The intent of this test was to obtain experimental data on the reactor vessel internals movements during the startup test program.

The results of this test were of particular interest in lieu of the "dropping of the lower internals" incident.

The instrumentation installed for the test was as follows:

1. Fourteen (14) maximum displacement indicators on the thermal shield to measure relative motion between the core barrel and thermal shield.
2. Seven (7) accelerometers on the vessel head to detect gross changes in internals response.
3. Thirteen (13) strain gages to three guide tubes to measure mean deflection and dynamic response imposed by the flow during operation.

MAXIMUM DISPLACEMENT INDICATORS

Maximum displacement indicators were designed and installed on RG&E at the locations shown in Figure V-1. The measurement of the gap indicated as DIM. "A" on the sketch following the hot functional test provided an indication of the maximum relative motion between the thermal shield and the core barrel

resulting from a combination of thermal differential expansion, hydraulic forces and vibration.

The internal spring loaded plunger was designed to follow the relative cyclic motion between the thermal shield and core barrel, thus causing the two stationary spring-loaded styluses to leave small markings on the plunger. These marks provided a direct indication of the magnitude of the vibratory motion.

With the exception of two locations, Number 13 at the top, and Number 2 at the bottom adjacent to a flexure, the total displacements were realtively small and consistent, and are in close correlation with expected results based on extrapolated data from model testing and from previous measurements on other reactors.

Vibratory motion measured by all the indicators was also small. The maximum motion, as interpreted from the plunger markings, are as follows:

Top		Double Amplitude	
#10, 13 & 14	-	.010	(± .005)
#9	-	.012	(± .006)
#11, 12	-	.014	(± .007)

Bottom

#6, 7	-	.008	(± .004)
#3, 5, 8	-	.010	(± .005)
#1	-	.014	(± .007)
#2, 4	-	.004	(± .002)

If this motion is conservatively assumed to be thermal shield motion only, i.e., the shield motion is ± 0.007 inch at the mid-point between supports, the stress corresponding to this motion is very small and within the allowable stress for infinite cycle loading allowed by the ASME Code by an order of several magnitudes.

Several facts are evident from a magnified observation of the scribe markings on the plungers from No. 2 and No. 13 indicators. The scribe marks on No. 13 are located in a position that indicates the plunger was projecting 0.080 inch (Dim. A=0.080) when the vibratory motion occurred. This indicates that No. 13 indicator was (1) not completely inserted at installation, (2) slipped soon after installation, or (3) a local thermal realignment occurred between the thermal shield and core barrel. The complete lack of marking in the completely inserted position indicates that the large gap is probably the result of either (1) or (2).

Even if the gap occurred as a result of item (3), however, the deflection is well below the calculated allowable of 0.180 inch between supports.

Indicator No. 2, however, indicates that the vibratory marking occurred with the plunger in the completely compressed position (Dim. A approximately = 0), so that the 0.030 inch gap did not exist during the hot functional test. It is also significant that the spring loaded plunger had been driven back into the displacement pin and jambed, so that it was not in contact with the core barrel after placement of the internals on the new storage stand. Although not completely conclusive, it appears probable that this gap was influenced by the initial impact with the storage stand. It is located almost directly opposite the initial point of impact.

Based on the very good condition of the internals, the lack of motion between components and the small vibratory motion of the thermal shield, the conclusion is that the RG&E internals as installed are in excellent condition and are adequate for their functional requirements.

ACCELEROMETERS

Seven accelerometers were mounted on the outside of the reactor vessel. Their locations and directions of sensitivity are shown on the attached sketch, Figure V - 2. The accelerometers were mounted on the top of the reactor and clamped to the 4" diameter head penetrations. Those on the bottom of the vessel were attached to the vessel wall by a magnetic clamp.

Signals from the (piezoelectric) accelerometers were amplified with charge amplifiers and recorded on a Visicorder and on magnetic tape. Data was taken when the desired reactor conditions occurred during hot functional and cold hydrostatic testing - during both one and two main cooland pump operation and with main coolant temperatures from approximately 120° F to 560°F.

Part of the intent of these accelerometers was to detect sharp transients, or abrupt changes in vessel motion that might result in the event that a significant abnormality occurred in the flow or internals vibrations during testing. No transients of this type were observed while the data were being taken or during subsequent analysis of the data. Further, no marked changes in the character of the signals was observed at similar reactor conditions during the test period.

STRAIN GAGES

Four active strain gages were attached to the upper end of three guide tubes (one dummy gage was mounted for noise measurement), in order to obtain measurements that indicated the static and dynamic deflections and loads imposed on the guide tubes during cold hydrostatic, and hot functional testing.

The maximum mean strain measured was 50.4 pin/in and the overall dynamic strain levels measured were $\pm$ 11.88 pin/in. These measured strains indicate that the guide tubes have an adequate safety margin. Direct verification of adequacy has also been obtained by visual examination after the hot functional test. The strain gages will remain in place in order to observe the core effect on the guide tube and vessel dynamic response.

B. Reactor Coolant System Vibration Test. RG&E S.U. - 4.1.8

The main function of this test was to verify that the vibrations of the reactor coolant pumps and the reactor coolant system piping and equipment are within acceptable limits during the pump operation. The test also provided reference data for the future operation of the reactor coolant system. The data sheets of figures V - 3 and V - 4 are the results of this test.

C. Preoperational Reactor Coolant System Leakage Test. - RG&E S.U. - 4.1.5

The performance of this test was necessary to satisfy the technical specifications that the leakage from the reactor coolant system did not exceed 10 gallons per minute from known sources or 1 gallon per minute from unknown sources.

Prior to running the test, the system was thoroughly inspected for visible signs of leakage.

The reactor coolant system was maintained at constant temperature and pressure for zero power conditions for the for the ten hour duration of this test. At the end of the test run, tank and pressurizer levels were compared to levels at test initiation and added or subtracted from the water inventory of the reactor coolant system. Makeup water to the system for the test period was measured. A mass balance of the

system was made and total leakage calculated. The results of this test satisfied the technical specifications.

D. Reactor Coolant System Thermal Expansion Test. RG&E S.U. 4.1.7

The major objectives of this test were to verify that the reactor coolant system could expand unrestrained during the system heat up from the cold condition to operating conditions, and also to establish reference data for the expansion of RCS components which can be used for future evaluations.

Basepoint measurements were taken at various points around the reactor coolant system with the system in the cold condition. These measurements were compared to measurements taken at the same points under "hot" conditions. An analysis of the data revealed no restraining problem.

E. Flow Coastdown Test - RG&E S.U. 8.3

The RG&E Flow Coastdown test was performed without incident on December 14, 1969. The data has been analyzed and found to agree favorably with the RG&E FSAR Figure 14.1.6-1. Curves of the reduced information are presented in Figures V-5 through V-9.

The signals for flow recorded during the tests were in the form of a differential pressure (ΔP) measurement. Flow as a fraction of nominal, is obtained by taking the square root

of the normalized ΔP value. Data was taken and reduced for the two loop total loss of flow, and for both single loop coastdowns, all from full flow.

Figures V-5 through V-7 show the individual loop coastdown curves determined from the plant data. In order to make a comparison with the design curve, a total core flow was determined by averaging the individual loop flows. These comparisons are found in Figures V-8 and V-9. The time to 50% flow for the 2-Loop coastdown was predicted at 12.3 seconds while the plant was found to take more than 13.5 seconds. The one loop coastdown also shows the FSAR curve reaching half flow sooner than the actual but the prediction has the slower flow up to that point.

It is therefore concluded that the plant coastdown rate is consistent and conservative with respect to the FSAR in order that departure from nucleate boiling be prevented. Although the core flow for the one loop loss of flow fell faster than predicted, the two loop coastdown is the limiting case and it is in agreement with the FSAR design.

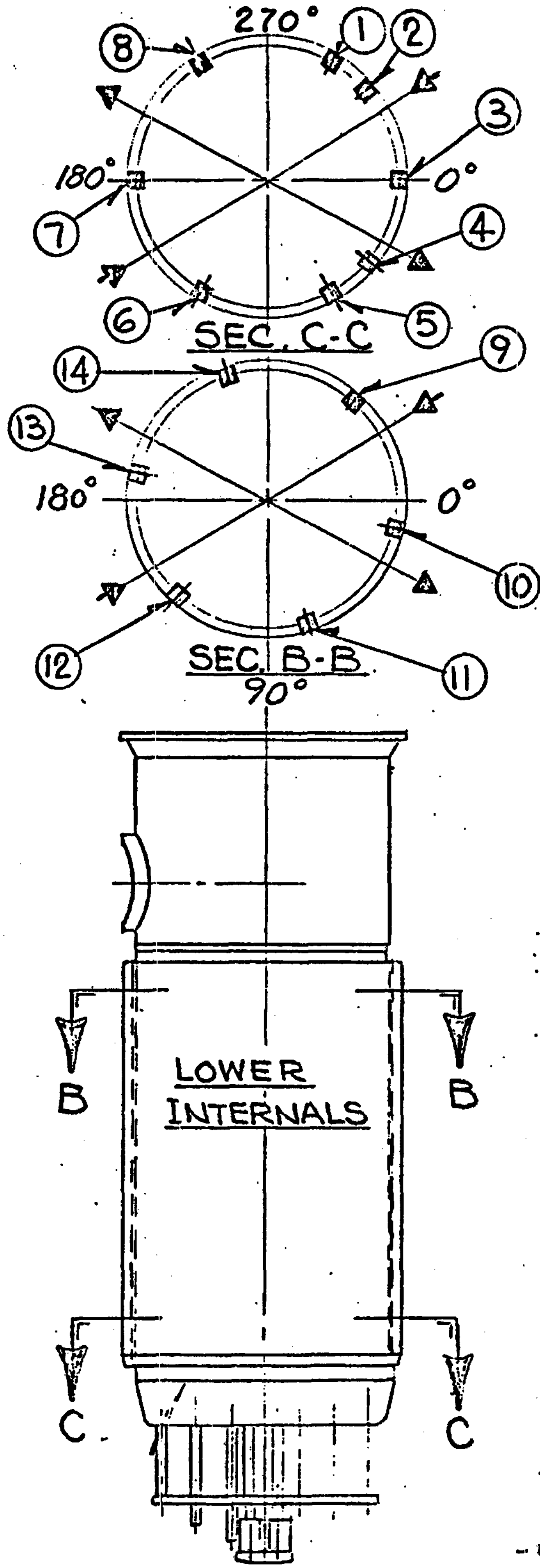
F. <u>Natural Circulation Test</u> - RG&E S.U. - 8.4

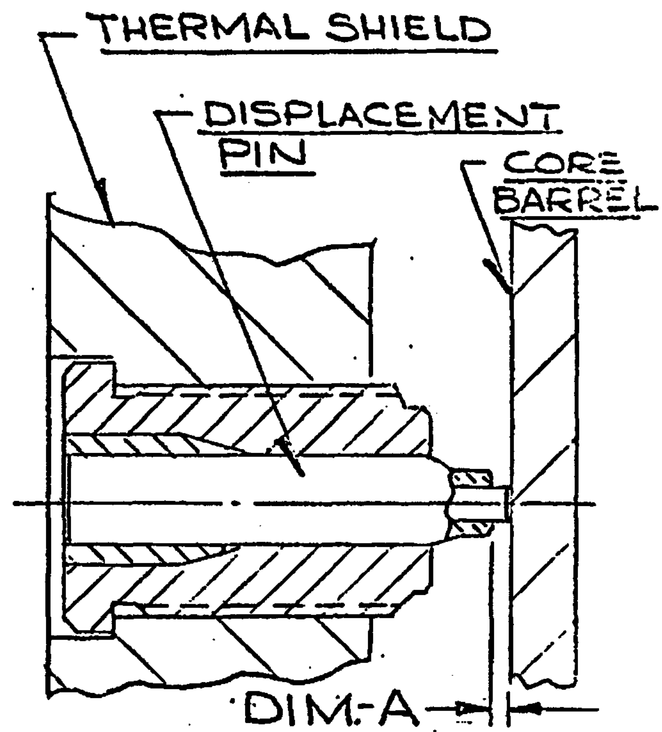
The RG&E Natural Circulation test was completed successfully on January 18, 1970. The data has been evaluated and was found to be in excellent agreement with the predictions reported in the FSAR, Section 14.1.12. The comparitive information

is presented in the figures V-10 and V-11.

A record of Nuclear Power, Coolant Average Temperature, Δ T, and pressure data taken from the control board instrumentation was checked against data trended on the plant computer during the test and found to compare favorabl y. A primary flow was then calculated, based on the power level (measured by the Nuclear Instrumentation System), and the other directory measured parameters. The data recorded for the flow calculation are shown in Figure V-10. Figure V-11 a curve of the FSAR prediction with the flow points calculated from the measured data at the test's two power levels.

It is thus apparent that Natural Circulation does occur and that it is more than adequate for decay heat removal. Furthermore, the flows determined from the plant data are in excellent agreement with the predicted curve.

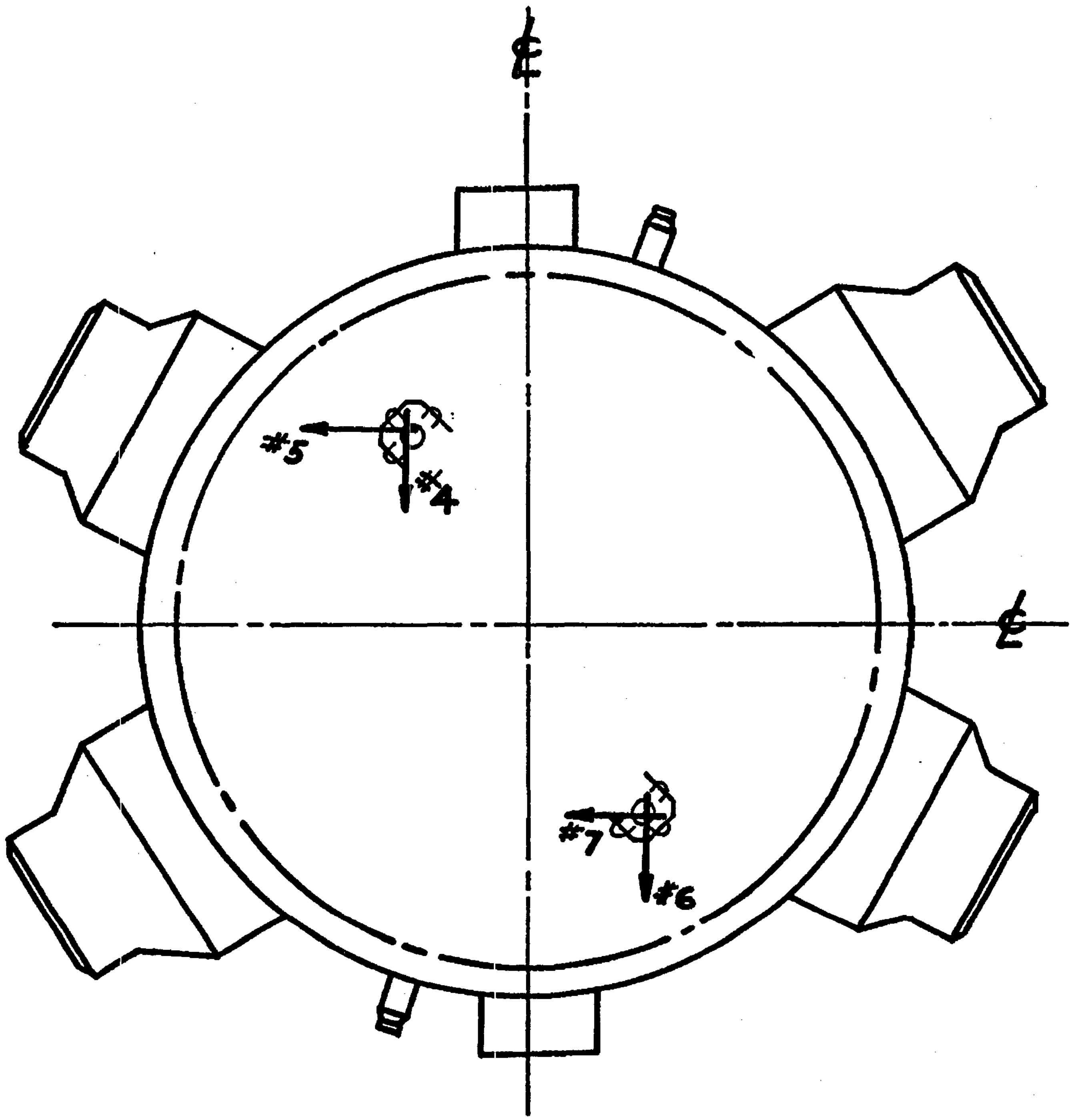




No.	DIM-A AS INSTALLED	DIM-A AS REMOVED
1	0.000"	0.022"
2	0.000"	0.030"
3	0.000"	0.012"
4	0.000"	0.002"
5	0.000"	0.010"
6	0.000"	0.008"
7	0.000"	0.008"
8	0.000"	0.010"
9	0.000"	0.012"
10	0.000"	0.008"
11	0.000"	0.016"
12	0.000"	0.017"
13	0.000"	0.088"
14	0.000"	0.015"

DISPLACEMENT INDICATORS
R.G.E. SITE

Figure V-1



TOP VIEW OF REACTOR VESSEL

FIG. V-2
SHEET 1

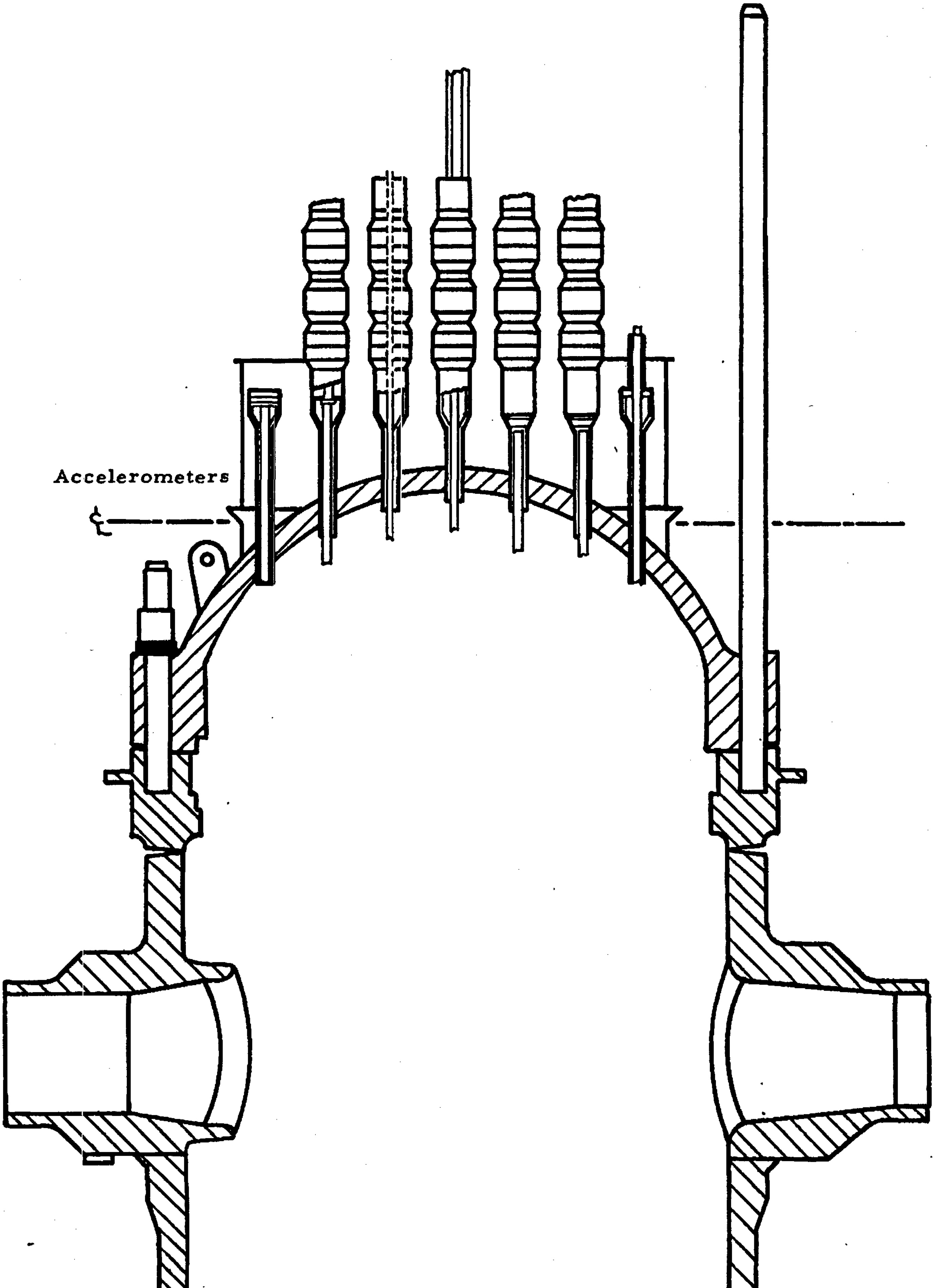
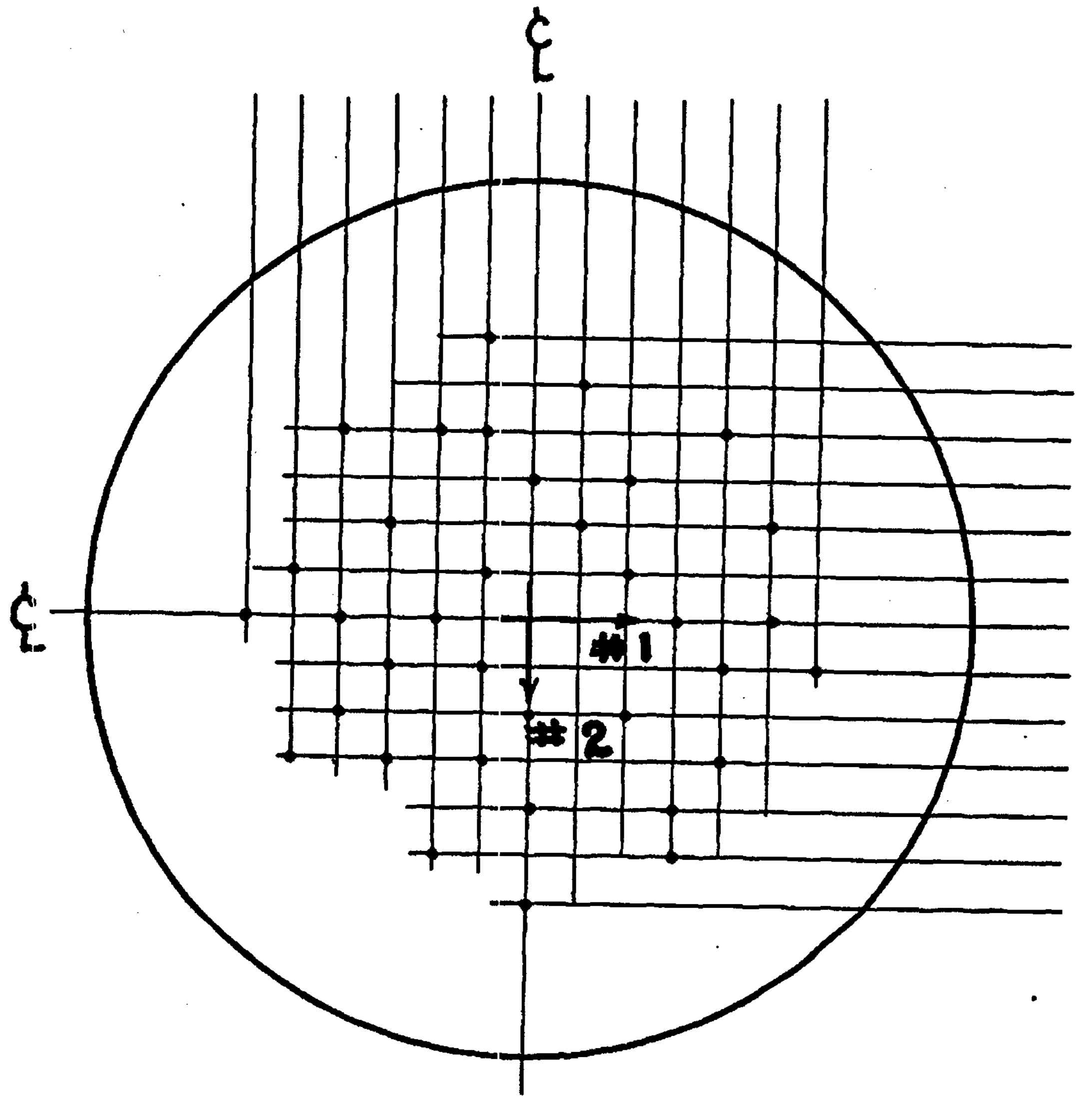


Figure V-2
Sheet 2



BOTTOM VIEW OF REACTOR VESSEL

Figure V-2
Sheet 3

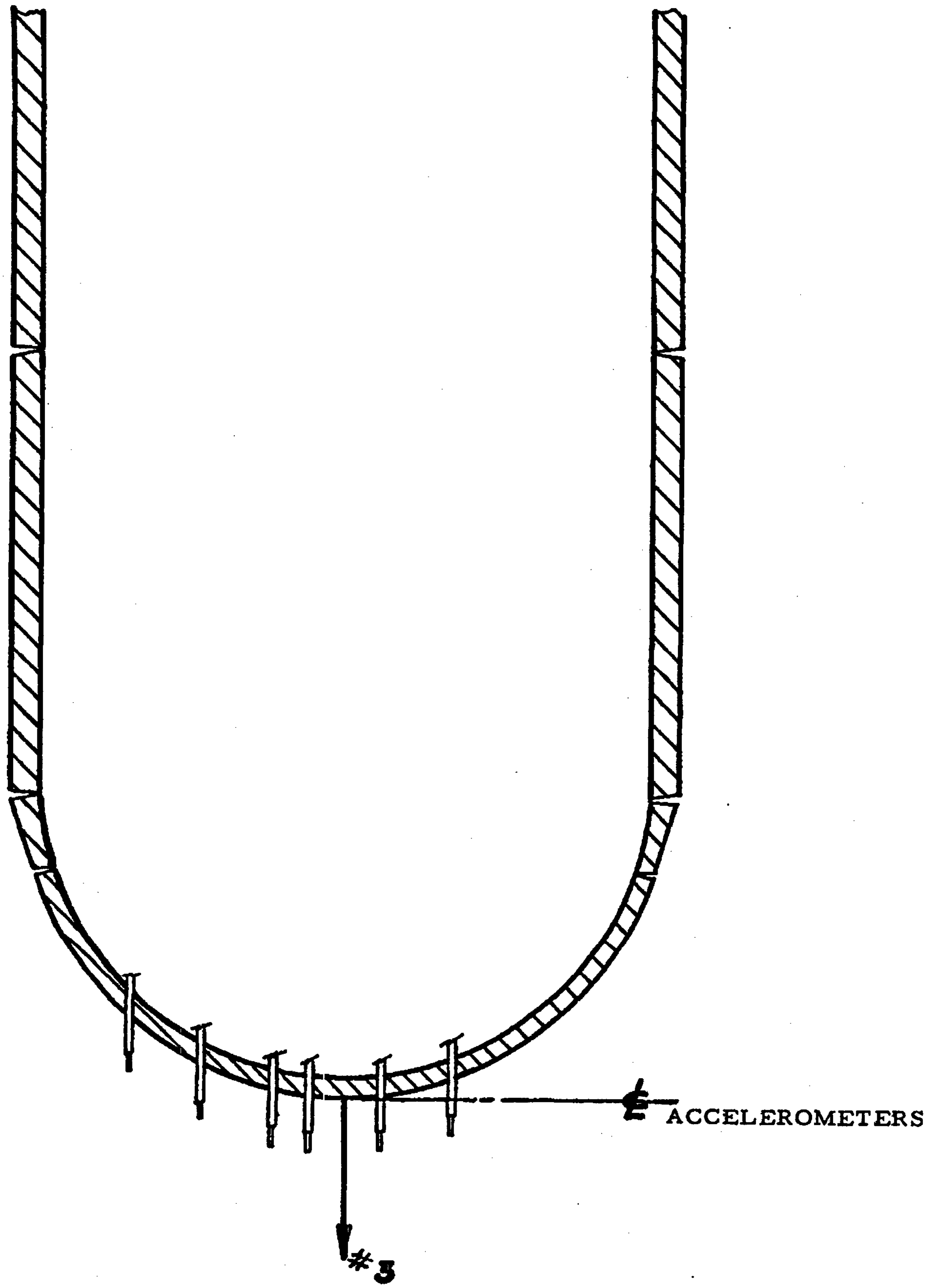


FIG. V-2
SHEET 4

DATA SHEET

11-5-69 1000 hrs — VIBRATION AMPLITUDE - MILS

Reactor Coolant Pump No. 1A

Hor. *	North Lower Mot. .5	East Lower Mot. .8	R3263 N. "A"
Vert. *	Pump Base North .5	Pump Base East .5	R3261 E. "A"
Hor. *	East Top Mot. .7	North Top Mot. .7	Vert. Top .5

Reactor Coolant Pump No. 1B

Hor. *	South Lower Mot. .7	East Lower Mot. 1.6	
Vert. *	South Pump Base .7	East Pump Base .5	R3267 S. "B"
Hor.	West Top Mot. 2.9	South Top Mot. 2.1	Vert. Top .5

Steam Generator No. 1A

* .28
(North Leg)
* .3

Loop A Hot Leg

* (vertical) .24

* (horizontal) .22

Loop B Hot Leg

* (vertical) .2

* (horizontal) .16

Loop A Cold Leg

* (vertical) .36

* (horizontal) .4

Figure V-3

	VIBRATION AMPLITUDE - MILS
Loop B Cold Leg	
* (Vertical)	.5
* (horizontal)	.7
CRDM	
* (Vertical)	
* (Horizontal)	

RCS Flow Rate 100%

RCS Temperature 550°F

RCS Pressure 2235 psig

* Indicate on the data sheet the location of the measurement.

The maximum vibration amplitude range specified for the R.C. Pump is as follows:

Normal	Maximum
1 Mil	2 Mils

Measured at main pump flange or on motor at running speed.

Remarks: The 2.1 mill vibration on the 1 B pump shall hopefully be reduced by an adjustment to the lower radial bearing. This work to commence 1-7-69. Bearing adjustment made to "B" pump 1-8-69 - Max. vibration 1.4 mils.

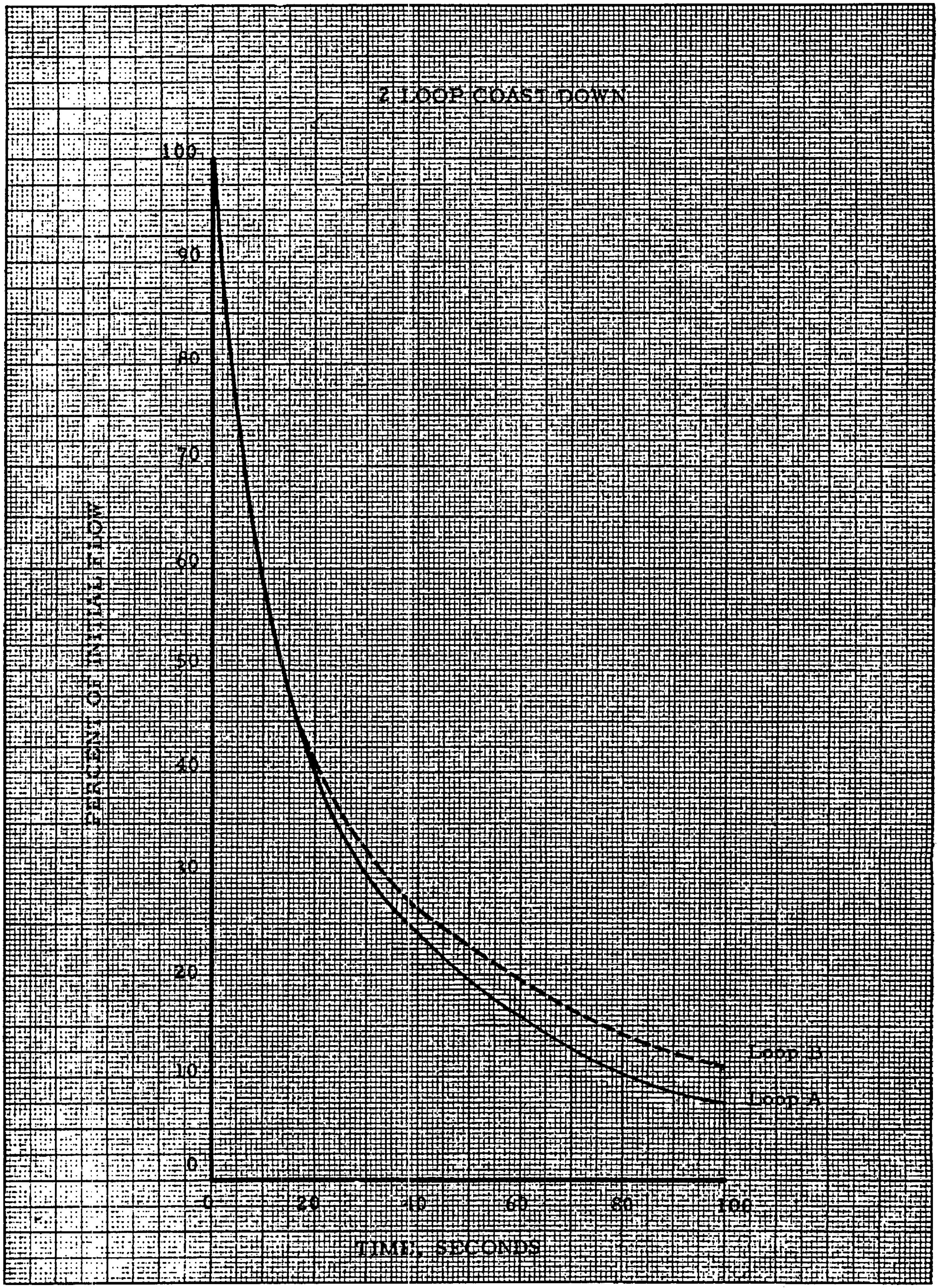
Performed by________________________ Date__________

Data Analyzed by________________________ Date__________

Westinghouse Observer________________________ Date__________

RG&E Observer________________________ Date__________

Figure V-4



10 X 10 TO THE CENTIMETER 46 1512
18 X 25 CM. MADE IN U.S.A.
KEUFFEL & ESSER CO.

Figure V-5

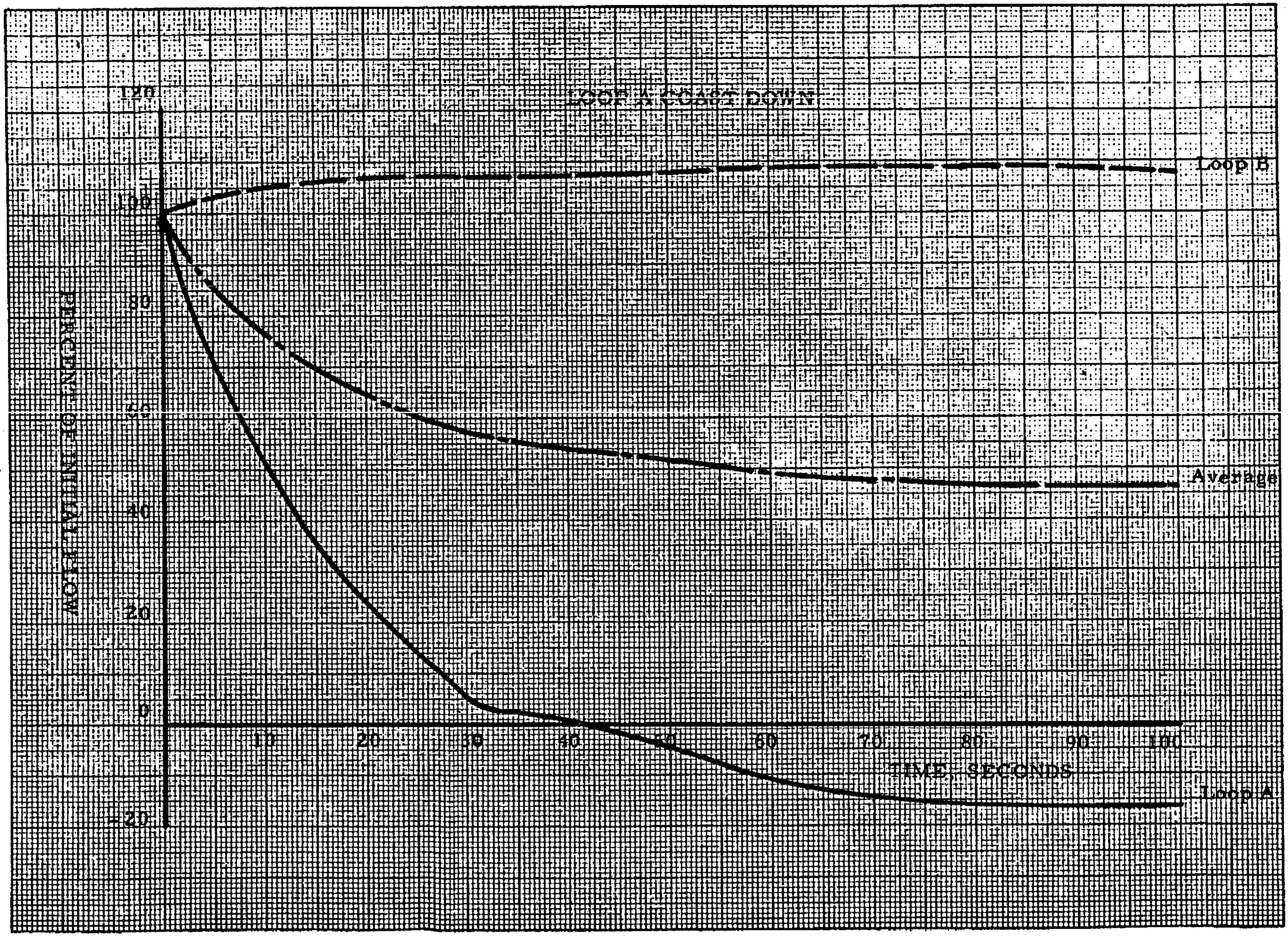

LOOP A COAST DOWN
PERCENT OF INITIAL FLOW
TIME, SECONDS
Loop B
Average
Loop A
120
100
80
60
40
20
0
-20
10
20
30
40
50
60
70
80
90
100

Figure V-6

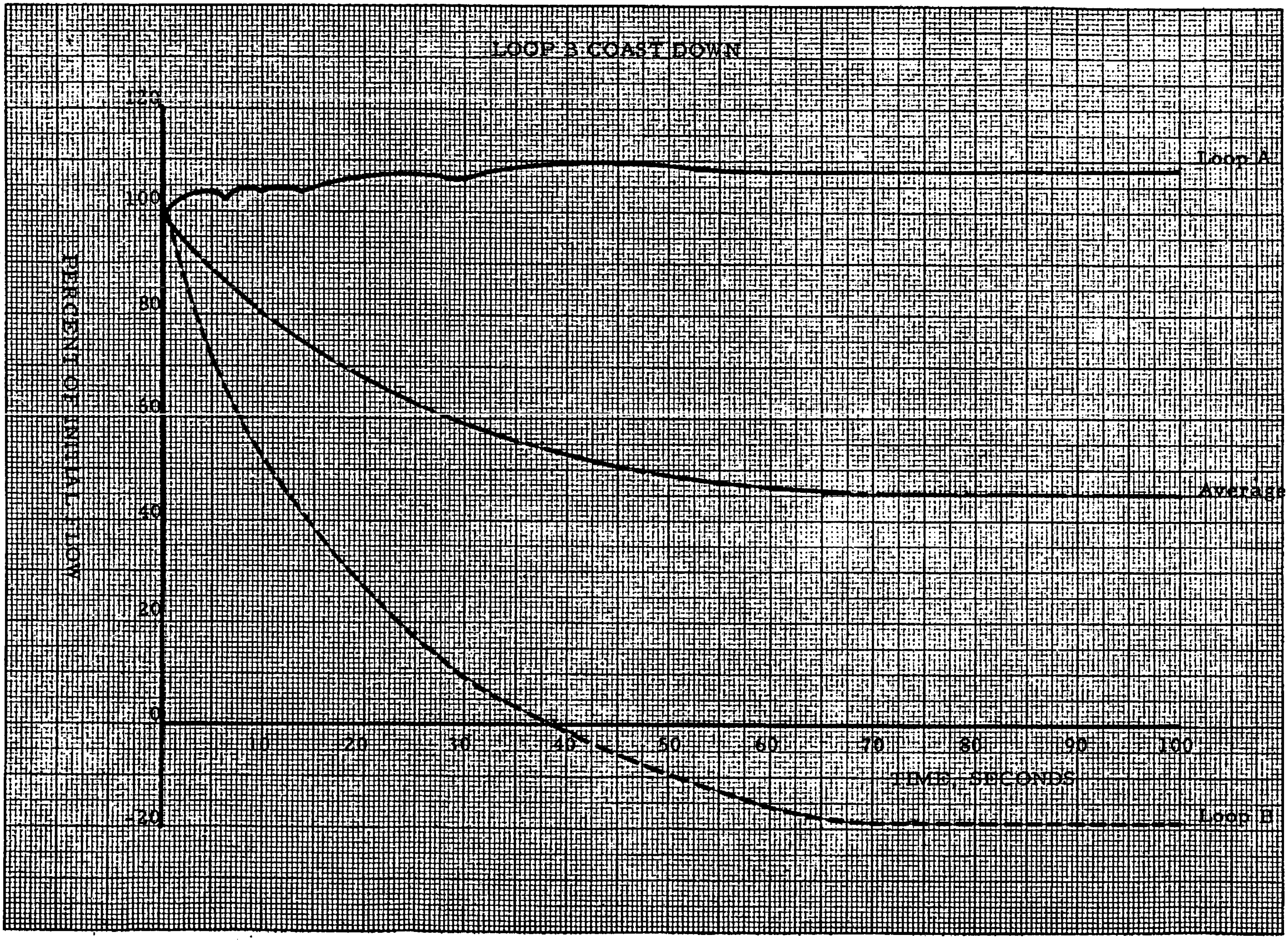

LOOP B COAST DOWN
PERCENT OF INITIAL FLOW
120
100
80
60
40
20
0
-20
10
20
30
40
50
60
70
80
90
100
TIME - SECONDS
Loop A
Average
Loop B

Figure V-7

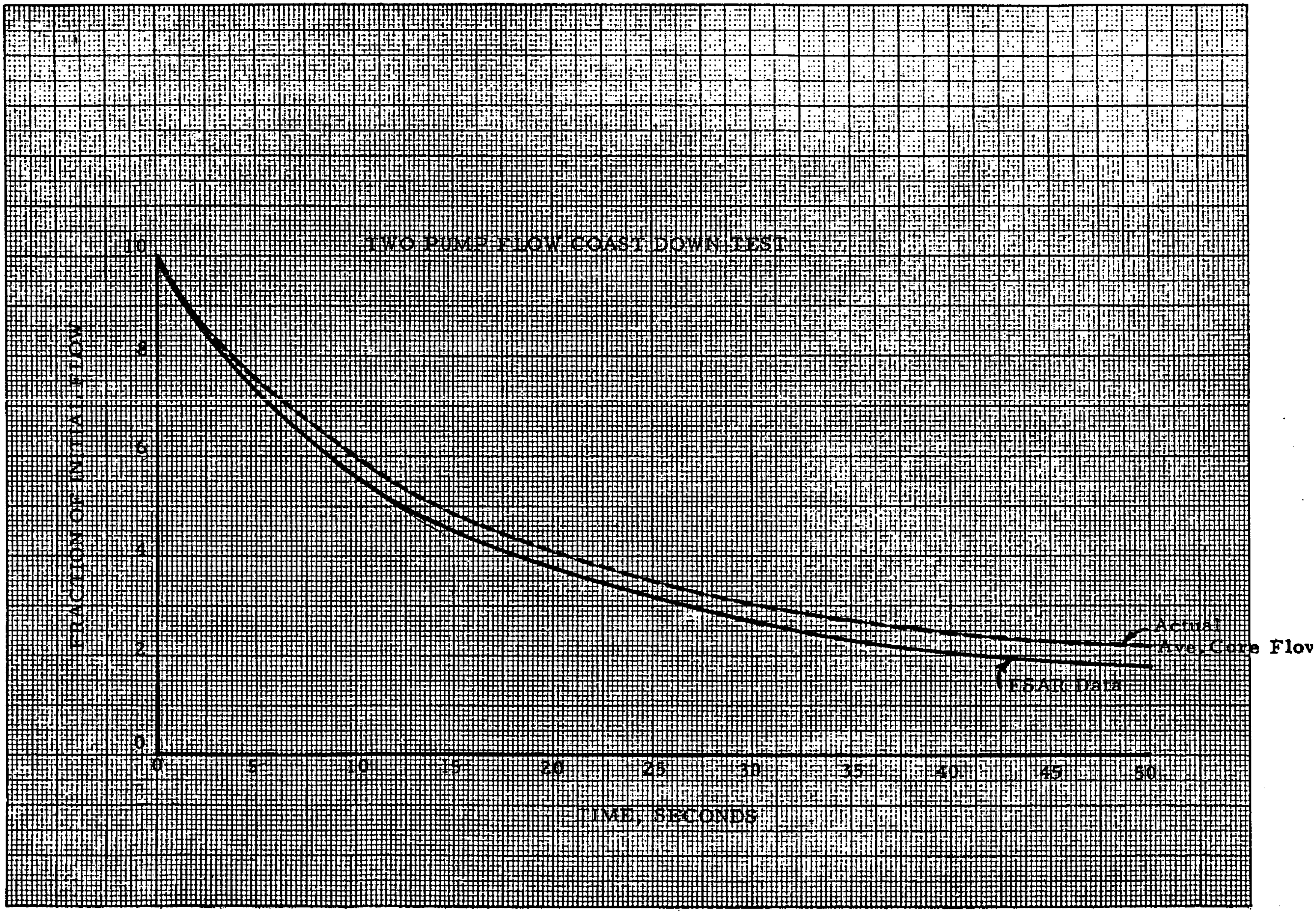

TWO PUMP FLOW COAST DOWN TEST
FRACTION OF INITIAL FLOW
10
8
6
4
2
0
0
5
10
15
20
25
30
35
40
45
50
TIME, SECONDS
Actual
Ave. Core Flov
FSAR Data

Figure V-8

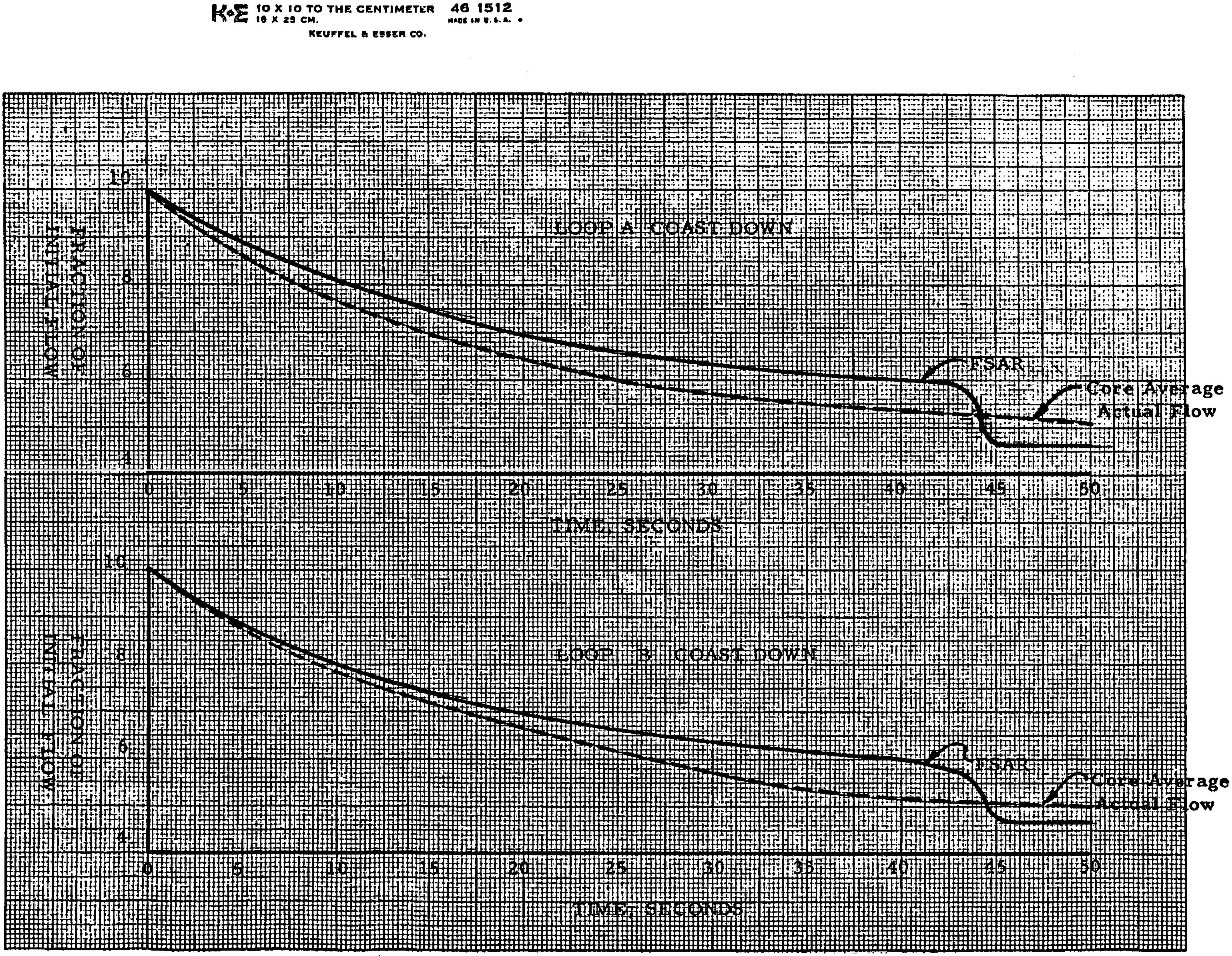

K&E 10 X 10 TO THE CENTIMETER 46 1512
18 X 25 CM. MADE IN U.S.A.
KEUFFEL & ESSER CO.
LOOP A COAST DOWN
FRACTION OF INITIAL FLOW
10
8
6
4
0
5
10
15
20
25
30
35
40
45
50
TIME, SECONDS
FSAR
Core Average
Actual Flow
LOOP B COAST DOWN
FRACTION OF INITIAL FLOW
10
8
6
4
0
5
10
15
20
25
30
35
40
45
50
TIME, SECONDS
FSAR
Core Average
Actual Flow

Figure V-9

RECORDED DATA

	After Equilibrium at approx. 2% Power	After Equilibrium at approx. 4% Power
Indicated Nuclear Power (Average of 4 Readings)	1.97%	4.175%
Coolant $T_{Average}$ (Average of 4 Readings)	550.3°F	561.5°F
Coolant Δ T (Average of 4 Readings)	25.5°F	40.0°F
Pressure	2250 Psi	2250 Psi
Flow - % of Nominal (Calculated from above data)	4.0%	5.25%

Figure V-10

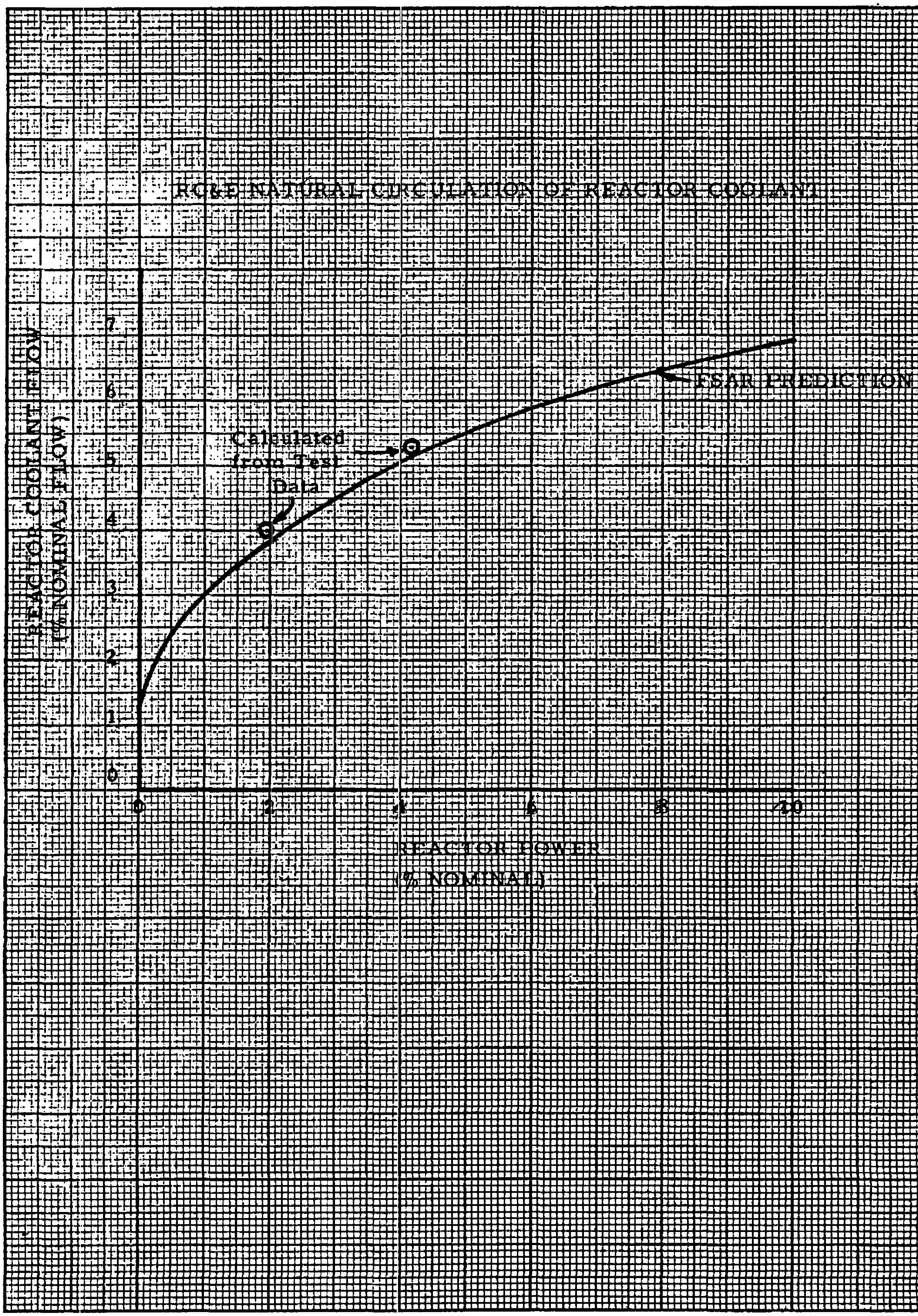

RC&E NATURAL CIRCULATION OF REACTOR COOLANT
REACTOR COOLANT FLOW
(% NOMINAL FLOW)
7
6
5
4
3
2
1
0
Calculated
from Test
Data
FSAR PREDICTION
0
2
4
6
8
10
REACTOR POWER
(% NOMINAL)

Figure V-11

VI. Miscellaneous Safety Related Tests.

A. Backfeed from the 115kv Grid. RG&E S.U. 4.30.3

The purpose of this test was to insure that power can be fed back from the 115kv grid through the main and auxiliary transformers to the station auxiliaries, in the event of an extended outage of of the station auxiliary transformer as specified in the FSAR. More specifically this test was to prove that the 115kv cable from Station 13A to the Ginna Plant, the 115kv to 19kv main generator transformer, the 19kv bus duct, and 19kv to 4.33 kv unit auxiliary transformer could be energized from the 115kv substation, without risk of damage to the transformer or the high voltage lighting arrestors.

The normal station and system safety holding rules were strictly adhered to during the test. To perform this test, it was necessary to disconnect the terminals of the main generator from the isolated phase buss duct by removing the flexible connectors in the lead box under the generator for the test duration. A visacorder for recording voltage transients was installed in the 19kv potential transformer secondaries.

The normal feed to the station auxiliaries during the existing plant conditions, (cold shutdown), is from circuit 767 through auxiliary transformer No. 12. This circuit was de-energized and the main transformer was energized from the 115kv system by

energizing Circuit 912. The results of the test follow:

Steady State Post Switch Voltage (no Auxiliary load)

A Ø - 68.5 Volts - 0.99 per unit

B Ø - 68.5 Volts - 0.99 per unit

C Ø - 68.5 Volts - 0.99 per unit

Peak Maximum Transient Voltage

A Ø - 1.22 per unit

A Ø - 1.06 per unit

C Ø - 1.06 per unit

Cycles to Near Steady State (clean Sine Wave)

1120 cycles

OCB Pole Closing Angle (Breaker 91202)

A Ø - 0.7°

B Ø - 0

C Ø - 2°

Note: This is not the only breaker that could be used for this test.

There was no evidence of any significant dynamic envelope occurring during this test.

The magnitude of the peak transient voltage less than expected. This could be due to a combination of two factors.

1. Location of the measuring point on the opposite side of a

3 phase wye-delta transformer from the impinging transient. However, even though higher per unit transients would probably have been measured on the 115kv side of the transformer, indications are, from our test results, that these were not excessive.

2. Extremely small OCB pole closing angles. This could change with the number of circuit breaker operations or the use of a different circuit breaker such as OCB No. 1G1372.

The harmonic disturbances on top of the 60 cycle fundamental lasted for a much longer time period than expected. However, they did not appear to be severe enough to cause any problems. Performed 9-21-69

B. <u>Blackout Test without Safety Injection.</u> RG&E S. U. 4.40.1
This test is basically concerned with the ability of the diesel generators to supply emergency power to the 480 volt busses in the event that normal outside power is lost. This includes the clearing of the busses of loading if outside power is lost so that the diesel breakers will not close to a fully loaded buss.

The loss of power was simulated by simultaneously tripping the 4160 volt supply breakers, 52/12A and 52/12B. Since the individual switch gear and 480 volt switch gear interlocks were

tested previously in the diesel test, no problems occurred.

Because they were not covered in other tests, the logic and opening and closing of the steam supply valves to the steam driven auxiliary feedwater pump were tested. Again satisfactorily.

C. Main Steam Isolation Valve Test. RG&E S. U. 4. 32. 3

It was the intent of this test to demonstrate that the Main Steam Isolation Valves function by simulating a HI-HI containment pressure alarm and that the valves close in the prescribed amount of time.

To prove that the valves would function by simulating a containment high pressure necessitated modifying the test procedure slightly to allow the test to be done in two steps because of plant status. The relays driven by the containment pressure transmitters were tripped manually to demonstrate steam line isolation. At a later date, the containment high pressure was simulated at the pressure transmitters to demonstrate that the relays mentioned above would trip. When this portion of the test was done, the valves were prevented from operating by removing the control air from the valve operator.

The timing of the valves was performed with satisfactory results since specified mazimum closing time is 5 seconds and the valves actually closed in 1 second. The maximum opening

time of the valves was observed to be 3 seconds.

The operation of the Main Steam Valve Isolation function was included in other tests and in the RG&E S.U. 9.8.1 all of the logic trains that actuate Main Steam Isolation were verified to perform as intended.

D. Fire Service Water Test. RG&E S.U. 4.20

This test was a functional test of the fire system intending to verify the design criteria of the booster, diesel driven, and motor driven fire pumps as well as insure that all fire detecting devices, alarms and control functions performed as intended. The test prodedure was deviated from to conform to the updated standards of NEPIA. All criteria were met with satisfactory results, which are conservatively stringent.

E. Electrical System Logic Test. RG&E S.U. 9.8.3

The purpose of this test procedure was to specify the operations necessary to operationally test the following systems:

1. Turbine and Generator Protection.
2. Emergency Power System Logic.
3. Rod Stop.
4. Turbine Load Reduction.

Where applicable these tests involved a checkout of the analog system followed by logic train "A" and "B" checks. Also, where possible, the tests were performed with and without blocking and

permissive circuits actuated. The actual tripping of circuit breakers, closing of valves, starting of diesel generators was not demonstrated in this test, but rather the activating devices, relays, controllers, etc., were monitored with the final action blocked. The performance of this test was carried out over a long period of time which included many retests as one might expect of a test of this type. Eventually, all components and functions of the systems being tested were tested satisfactorily.

F. <u>Reactor Protection System Operational Test.</u> RG&E S.U. 9.8.1 This test procedure is very similar to the preceeding test procedure, the electrical system logic test, testing to provide the operations necessary to operationally checkout the reactor trips of the reactor protection system. The checkout involved a test of the analog system tripping followed by logic train "A" and "B" testing. The logic system testing was done with and without overing manual or blocking circuits.

It was first demonstrated that the reactor trip breakers would open automatically and then for the remainder of the test, the trip breakers were prevented from opening and the devices that actually tripped the breakers were monitored for performance. Once again, this was a long and complex test that was eventually completed with all objectives met satisfactorily.

G. Reactor Coolant System Hydro Test. T - 1W-2.1

The function of this test was to verify the integrity and leak tightness of the reactor coolant system and the high pressure portions of the auxiliary systems at 3105 psig (1 1/4 times the design pressure). All the necessary precautions were taken before the start of the test, in that the system had been flushed with hi-grade water, the water volume of the RCS system was within the chemical technical specifications for cold conditions, pressure relieving devices were set to relieve at 3120-3170 psig, the participating systems were aligned, no visible leaks were apparent, all possible safety precautions had been taken and the temperature of the reactor coolant system was above that necessary to pressurize the system.

The Reactor Coolant System was then pressurized to 1000 psig. with the charging pump and HCV-123 (excess letdown pressure control valve). Upon reaching 1000 psig, the pressure was maintained constant while inspection parties investigated the systems involved for leaks. This procedure was followed for 1500 psig, 2000 psig, 2500 psig, and 3110 psig with only minor problems encountered. This test was successfully completed March 1, 1969 at 1800 hours.

H. Ventilation Systems Tests

Several tests were written and performed on the various vent-

ilation systems of the Ginna Plant. The primary purpose of these tests was to functionally check out the systems and to insure that design flow rates were achieved without overtaxing components and to ultimately balance the systems for flow. These tests were performed by Thomas & Young Associates with RG&E personnel in attendance. Upon completion of these tests, RG&E engineers spot checked the various systems using RG&E test equipment to verify the test data.

I. Pre-operational Containment Vessel Leak Rate Test

The object of the initial pre-operational integrated leakage rate test was to establish the degree of leak tightness of the reactor containment building, penetrations, and isolation valves at the design pressure of 60 psig and to establish a reference test for subsequent retests at 35 psig. The allowable leakage was defined by the design basis accident applied in the safety analysis in accordance with the site exposure guide lines set forth in 10CFR-100 for the Ginna Station.

The allowable integrated leakage rates are as follows:

Conditions	Allowable Integrated Leak Rate Percent Per Day (2)
Accident (60 psig @ 286F)	0.1000
Test (60 psig @ 93F)	0.0731
Test (35 psig @ 93F)	0.0597

During the test period of six and one-half days, the structural integrity test on the reactor containment structure was also conducted. A maximum internal pressure of 69 psig (1.15 times 60 psig design pressure) was used for the structural integrity test. The leakage rate data was gathered over a period of at least 24 consecutive hours after conditions were stabilized at each pressure. Following each 24 hour period, a controlled leakage rate was superimposed on the reactor containment building to verify and validate the test instrumentation.

1. The reactor containment structure leakage rate at 59.9 psig and 93.2 F was found to be 0.0219 $\pm$ 0.0168% per day.
2. The leakage rate at 35.1 psig and 93.8 F was -0.0059 $\pm$ 0.0180% per day. The negative value indicates that the leakage rate was less than the instrumentation sensitivity and ability to react in a relatively short (24 hours) period. With a longer test time, the reduction in error would have led to a better averaging and more definition of the finite rate. When a controlled leakage rate of 4.9 lb/hr was superimposed on the vessel at 35psig, the calculated rate of 5.05 lb/hr demonstrated the satisfactory performance of the instrumentation.
3. Primary boundary leaks were noted in six penetrations during the test. The resulting leakage was, of course, a part of the overall leakage rate.

4. Comparison of test instrumentation calibrations before and after the test were made and negligible differences were noted.

5. It is not necessary to superimpose a fixed leakage rate at <u>both</u> pressure levels; one is considered sufficient, preferably at the retest condition.

Figure VI-1 describes the actual containment vessel pressure versus time. Figure VI-2 describes the pressurization system.

J. <u>Structural Integrity Test GIA Report 1720</u>

The purpose of this report was to present the results and observations made on the reactor containment vessel during the Structural Integrity Test on April 11, 1969 to April 14, 1969 and during subsequent depressurization which was concluded on April 18, 1969. The conclusions of the Structural Integrity Test were obtained from the interpretations of test data and responses of the reactor containment vessel when subjected to a maximum internal pressure of 69 psig (115 per cent of design pressure-60 psig).

Most of the Structural Integrity Test instrumentation performed well and their recorded data are regarded as being valid. Some discrepancies in the data were noticed. The significant discrepancies were noted and discussed. The

number of discrepancies was small compared with the amount of data recorded.

The results of the Structural Integrity Test showed the stresses strains, and displacements were within the limits as defined in the Final Facility Description and Safety Analysis Report (FSAR) and the GAI predicted results. The whitewash areas revealed crack patterns and spacings in good agreement with GAI's prediction; no horizontal cracks in dome concrete except for construction joints. The base shear restraint was stiffer than anticipated. The strains and displacements of the cylinder wall, the discontinuity of dome and cylinder wall, and dome revealed the structural stiffness of the containment vessel is greater than anticipated.

The structural capacity of the Containment Vessel meets and exceeds its imposed criteria.

K. <u>Reactor Protection System Operation Time Response Test</u> - RG&E S.U. -9.7

The intent of this test was to determine the response time from the time the plant protection parameters reach their trip set-points until the tripping time of the reactor trip breakers. In the procedure, the reactor trip time from the de-energizing of the under voltage coil to the actual tripping of the breaker was recorded and thereafter in succeeding tests, the time from trip setpoint to operation of the under voltage coil. From this information total time from trip setpoint to breaker trip was determined for each of the trip parameters.

The trip response time limits as specified in section 14 of the FSAR were proved to be conservative by the results of this test.

NOTES:
1. S.I.T. - STRUCTURAL PROOF TEST.
   I.L.R.T. - INTEGRATED LEAK RATE TEST.
2. INCREASE PRESSURE AT APPROXIMATELY 5 PSI/HOUR.
   DECREASE PRESSURE AT MAXIMUM 10 PSI/HOUR.
3. 5 HOUR PERIOD AT 14 PSI FOR I.L.R.T. MAY VARY.
4. (*) MEASUREMENTS MADE BY SKELETON CREW.

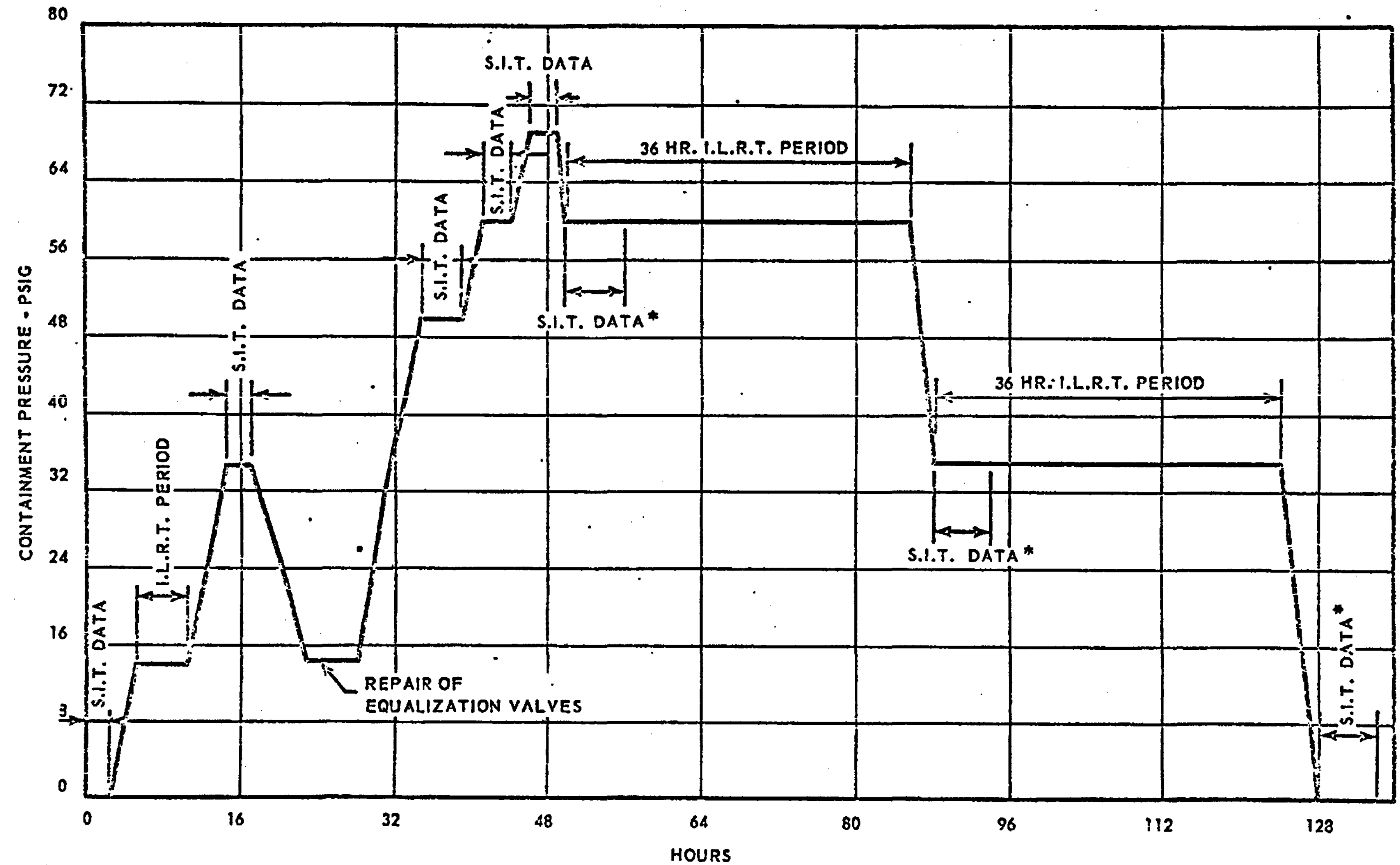


Figure VI-1

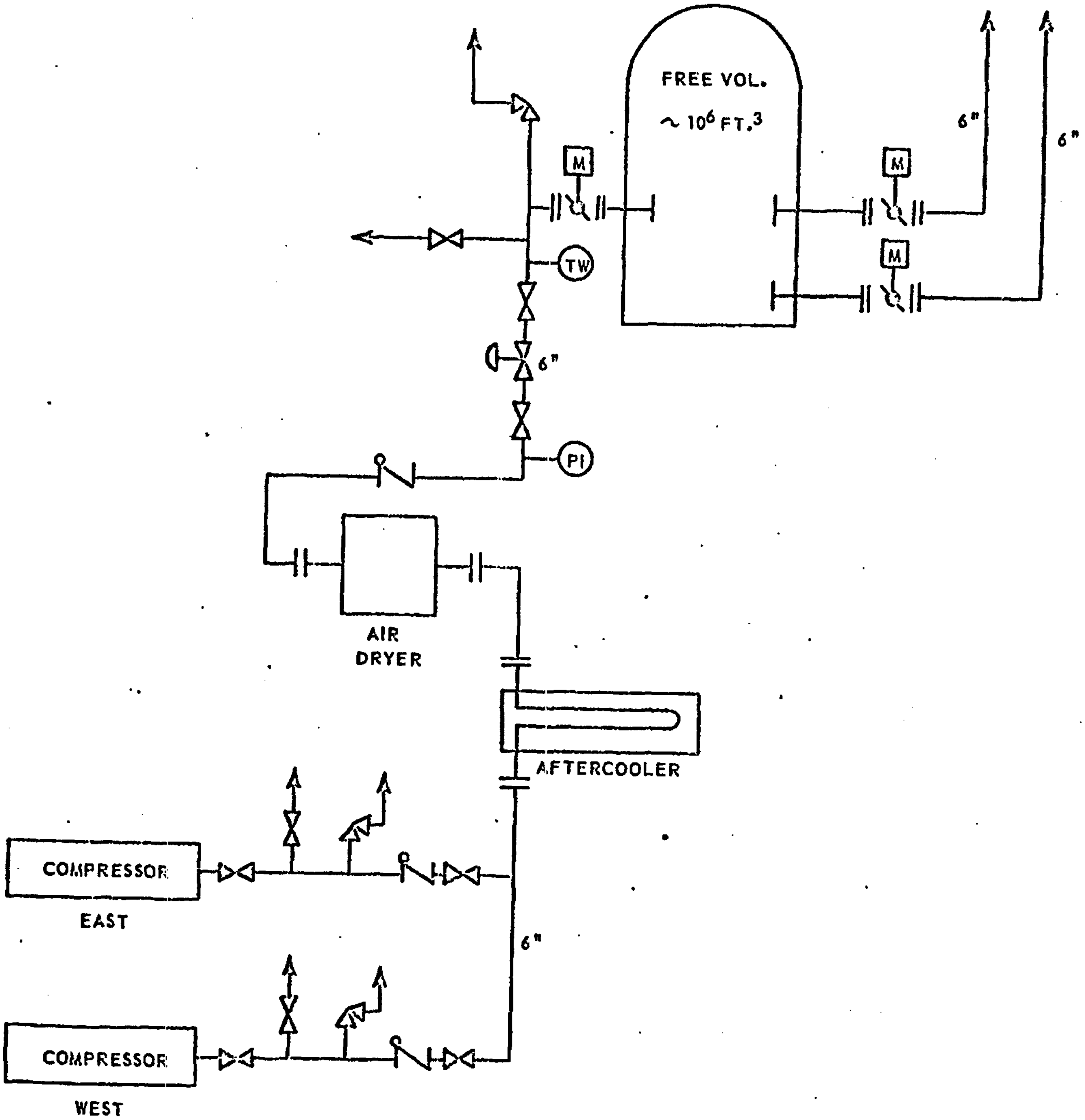

FREE VOL.
~ 10⁶ FT.³
6"
6"
M
M
M
TW
6"
PI
AIR
DRYER
AFTERCOOLER
COMPRESSOR
EAST
6"
COMPRESSOR
WEST

Figure VI-2

VII. Operational and Transient Tests - RG&E - S. U. 8.1.1

The tests of this catagory were designed to test the reactor control and protection systems response.

A. 10% Load Swing Test at 30% Power

The purpose of this test was to introduce a 10% load decrease and verify the nuclear plant transient response including automatic control systems performance and then introduce a 10% increase in load and verify the response and performance again.

The power level was 113 MWe when the test began and 70 MWe after the 10% reduction of load. The load increase was from 70 MWe to 113 MWe. In either case the control system brought the nuclear plant smoothly to the new power level, and there was no measureable amount of nuclear power overshoot. No alarms were observed on the 10% load decrease. Alarms were observed on both steam generators on the load increase.

In both cases rods moved at full speed for about 30 seconds and then for a short period at low speed. The rods remained stationary for some 8 minutes after which they moved 2 or 3 steps in the reverse direction at about 1 or 2 steps per minute. Steam generator control was smooth and no manual intervention was necessary. On the decrease in load the level in the steam generators decreased about 5% and on load

increase the level rose about 5%.

Tave swing was limited to about 2 degrees F. The pressurizer pressure swings were limited to about 20 psi.

B. Generator Trip Test - RG&E S.U. - 8.2.1

The objective of this test was to verify the ability of the automatic control system and the secondary plant to sustain interaction between systems and accomodate a net electrical load loss from below a 50% power level. The test results would be evaluated to determine possible changes in control setpoints in order to improve the transient response based on actual plant operation.

The initial power level of the plant was 110 MWe. The main transformer high side circuit breakers were opened to achieve loss of load. The final power level after the trip was 12 MWe, enough to sustain the plant auxiliary load. The control system responded smoothly and equilibrium conditions were reached in 15 minutes after loss of load. Controlling rod control bank D moved into the core from 194 steps out of the core just prior to loss of load to 65 steps out of the core at equilibrium conditions. This test was successful.

C. 10% Load Swing Test at 75% Power Level RG&E S.U. - 8.1.2

This test procedure verified the nuclear plant transient

response, including automatic control systems performance, when step load changes were introduced at the turbine generator. This test had been performed at a 30% power level previously. The plant load at initial conditions of this test was 348 MWe.

A step change to 291 MWe was introduced. After equilibrium conditions were reached a step change back up to 348 MWe was introduced.

No problem was incurred with either step change. The control system brought the plant to the new power level in approximately 3 minutes. There was no noticeable overshoot of any major variable. The rods stepped into the core at a rate of 72 steps per minute for 35 seconds on the load decrease and stepped out at a rate of 72 steps per minute for 40 seconds on the load increase.

Alarms on load decrease -

Steam Generator Level Setpoint Deviation. Loop A

Steam Generator Level Setpoint Deviation. Loop B

Pressurizer Low Pressure

Feedwater Heater and Drain Tank Level

Alarms on load increase -

Steam Generator Level Setpoint Deviation. Loop A

Steam Generator Level Setpoint Deviation. Loop B

Pressurizer Low Pressure

Feedwater and Drain Tank Level

Charging Pump Speed.

D. 50% Load Reduction from 75% Power Level - RG&E S.U. - 8.6.1

The purpose of this test was to verify the ability of the automatic control sytem and the ability of the secondary plant to sustain a fifty (50) percent load rejection from seventy-five (75) percent of full power, and the interaction between the systems, particular attention was paid to the operation of the steam dump system. Figures VII-I through VII-5 are some of the more interesting recordings of process variables. The 10% load swing test at 75% power preceded this test by a short time and the variations of the process variables for both tests can be seen in the aforementioned figures. The test was begun with a power level of 347 MWe and control rods of the controlling D bank at 215 steps out of core. Following the 50% load reduction, the plant leveled off at equilibrium conditions in 17 minutes and 138 MWe and a "D" bank position of 35 steps out of core.

The turbine power was run back smoothly during the reduction. Margin to delta T trips increased smoothly. Rods moved in at maximum speed for 1 minute and 12 seconds. Delta T setpoint 1 dropped to 48 degrees F while actual delta T dropped faster. Six steam dump valves opened and gradually modulated

down to two valves open and oscillating slowly but acceptably.

Six minutes after test initiation rods were at 69 steps out of core on "D" bank. Pressurizer level rose from 41% to a peak of 48%.

Alarms that functioned during load reduction -

Steam Generator Level Deviation A & B

Hotwell Level - High

Steam Generator Hi Feedwater Flow Loop A

NIS Power Range Upper Dectector - High Flux Deviation

Pressurizer Low Pressure

High Feedwater Flow Loop B

Steam Generator Lo Level Loop A Single Channel Alert

Feedwater Heater and Drain Tank Level

NIS Power Range Lower Detector High Flux Deviation

Average T average Minus T Reference Deviation

Steam Generator Hi Level Loop A Channel Alert

Steam Generator Hi Level Loop A

Feedwater Pump Seal Water Lo Differential Pressure

It can be seen on the "A" steam generator feedwater flow recording that there is instability of flow. This situation has since been corrected by changing the "A" steam generator feedwater valve controller response characteristics. The control system was allowing the "A" steam generator level

to reach 68% where the feedwater isolation scheme is activated accounting for the sharp decrease in flow. The sudden increase in flow after an isolation occurrence is caused by the automatic resetting of the feedwater valve control whereby the valve is allowed to go open again.

E. 100% Power Level Transient Tests

A 10% and 50% load swing test was performed at the 100% load level that were identical to the same load swing tests at 75% power level. The results of these tests were satisfactory and similar to those at the 75% level. On March 14, 1970 a plant trip test from 100% power level was successfully conducted. The purpose of the test was to verify the ability of the primary and secondary plant to sustain a trip from 100% power and bring the plant to a hot shutdown condition in an orderly ~~in an orderly~~ manner. The test was initiated by pushing the manual turbine trip button on the main control board. The following was verified:

1 - that the turbine and reactor trips did occur

2 - that the steam dump valves did open

3 - that pressurizer safety valves and steam generator safety valves did not open

4 - that the safety injection system did not operate

(BLANK)

5 - that all control rods were inserted in the core

100% trip alarm annunciations

2200 hrs - Manual Turbine Trip

Reactor Trip

No. 1 Gen. Voltage Regulator Field Forcing

Turbine Valves Single Channel Alert

Turbine Valves Auto Stop

Air to Extraction Dump Valves Tripped

Feedwater Heater and Drain Tank Level

Condenser Hotwell Level

Condensate Header Pressure

FWP Seal Water Lo Diff. Press.

FWP Lo Suction Pressure

FWP Light Load

FWP Seal Water Filter Line

Aux. FWP Light Load

Reactor Coolant Low Tave Loop A and B

Reactor Coolant Tave Deviation

Ave T Ave Deviation

Pressurizer Low Pressure

Pressurizer Safety Valve Hi Temp

NIS Power Range Upper Hi Flux Deviation

NIS Power Range Lower Hi Flux Deviation

NIS Power Range Rod Stop - Rod Drop

FIRST OUT ANNUNCIATOR

Turbine Auto Stop

Turbine Valves

Steam Generator Lo-Lo FW Level Loop A

Steam Generator Lo-Lo FW Level Loop B

Steam Dump Armed

Steam Generator Level Setpoint Deviation A &B

Rod Bottom - Rod Stop

Rod Control Urgent Failure Rod Stop

115 kv Panel

2210 Pressurizer Liquid Hi Temp

2215 Condensate Level

The plant functioned as expected with no major deviation from design intent.

F. Operational Dynamic Rod Drop Test RG&E S. U. - 8.5

The purpose of this test was to:

1. Demonstrate the operation of power range rod drop detection circuits and to provide a basis for the optimum adjustments of setpoints

2. Demonstrate the operation of the "turbine runback" controller and blocking of automatic rod withdrawal

3. Evaluate the plant transient response following a dropped rod and demonstrate the adequacy of the dropped rod recovery procedure

Plant power level was 40% at test initiation. The selected rod J-10 was dropped by removing the fuse from the rods stationary gripper coil circuit. The nuclear plant control system responded smoothly during this transient, but the "turbine runback" system did not reduce turbine load sufficiently to compensate for the reactivity decrease caused by the dropped rod. The turbine runback was completed manually.

The dropped rod detection was successful as can be seen in Figure VII-6. The four recordings of the figure are of each of the nuclear power channel signals. The two traces of each recording are the signals of the upper and lower ion chambers of a channel.

The dropped rod was detected by the rod position indicator on the main control board and the illumination of the rod bottom light. Verification of the dropped rod was made by the rod position digital voltmeter on the main control board and in-core thermocouple temperature computer printout. Verification could also have been made by running a flux map. On December 10, 1969, while at 30% power, rod J-7 was dropped to the bottom of the core and a flux map taken at that time confirmed the satisfactory detection of a dropped rod by flux mapping.

The following alarms were actuated during the transient:

1 - NIS Power Range Upper Detector High Flux

2 - Deviation of Auto Defeat

3 - NIS Power Range Channel Deviation

4 - NIS Power Range Rod Drop Rod Stop

5 - Rod Bottom Rod Stop

6 - Steam Generator Level Deviation Loop A

The dropped rod recovery procedure was proven adequate in this test.

This test was successfully rerun the following week after the initial attempt with a satisfactory turbine runback performance.

G. Delta T Zero Power Alignment and Delta T Channel Span Adjustment RG&E S. U. -9. 3. 1 and S. U. - 9. 3. 3.

The Delta T zero power alignment test provided instructions for the zero alignment for all four Delta T channels. The normal RTD inputs into the Dana Amplifier (first amplifier of the reactor control and protection system) were disconnected and precision decade boxes were connected to the input of the Dana Amplifier and a direct reading voltmeter connected to the output of same. A linearity check of the amplifier was made using the resistance values provided by the test procedure. With the plant at hot shutdown conditions the amplifier was

adjusted to produce an output corresponding to 0.0 deg. F.

The Delta T channel span adjustment test provided a curve of amplifier output versus plant load. Upon reaching approximately 75% power, a calorimetric was performed to determine actual level. The Dana Amplifiers of each of the protection channels were span adjusted for the actual power level to provide an output as dictated by the linear curve of amplifier output versus plant load.

H. Nuclear Instrumentation Calibration and RCS Flow Confirmation
RG&E S.U.-9.3

The purpose of this procedure was to specify the requirements for obtaining data for nuclear instrument calibration and RCS flow confirmation and to check the performance of the nuclear instruments by:

1. Obtaining a plot of anode voltage versus source range instrument output for use in setting source range anode voltage.
2. Obtaining nuclear instrument channel overlap data during increases and decreases in power
3. Plotting power range detector currents to verify linearity of detector outputs.

4. Determining operational settings of instrument compensating voltages and test current values.
5. Obtaining a plot of detector voltage versus output for intermediate and power range output for use in setting detector voltage.

A plot of source range detector (B10) anode voltage versus detector output in counts per second was obtained for each source range detector as follows:

1. Prior to core loading and prior to initial criticality, data was obtained for anode voltage plot using startup source.
2. One to two hours after shutdown from power operations of at least 500 MW days. (These plots were performed with neutron flux resulting from gamma-neutron reactions in the core and a significant gamma field incident on the detector).

With the source range channel adjusted per RG&E S. U. 4.8 of NIS Instruction Manual, anode voltage was varied in 25 volt steps over its adjustable range, no exceeding the maximum allowable operating voltage of 1000 VDC. Data was obtained of anode voltage versus CPS, and plotted for conditions specified in Section 1 and 2 above. The anode voltage setting was determined from the plot using the criteria that the voltage should be set at a point above the start of the plateau, corresponding to one third of the voltage plateau length. The anode voltage

was set and recorded on data sheet.

Immediately after anode voltage data was obtained for the conditions of 2 above and after setting the anode voltage, the discriminator voltage was varied in 0.2 volt steps over the operating range, data obtained to perform plot of discriminator voltage versus CPS. Discriminator voltage was adjusted to a point determined from plot.

The four power range nuclear instrument channels were calibrated based on a calorimetric measurement of the secondary system. The power delivered by each steam generator was determined by measurement of feedwater flow, feedwater temperature, and steam pressure. A second method of determining the power delivered by the reactor is by measuring the Delta T across each RCS loop and the reactor. The Delta T measurements were used to verify the feed flow method and were also used as a means of verifying loop flow. Measurements of feed flow were made by venturi meters installed in the feed flow lines to each steam generator. Differential pressure instruments installed across the venturi meters indicated differential pressure which was used to determine reactor power from a curve of Feedwater Temp. versus the Square

Root of Differential Flow Pressure. Percent reactor power is determined for each power level and a calorimetric calibration was performed, by summing the power being delivered by each steam generator as determined from the curve (less net thermal input due to pump operation, radiant heat loss and letdown) and dividing by the design full power output, computed as follows:

$$\text{Power } \% = \frac{(\text{P Loop "A"} + \text{P Loop "B"} - \text{P Heat Gains}) \times 100}{4437 \times 10^{6} \text{ Btu/hr}}$$

In performing a calorimetric calibration, plant power was increased to the approximate level as indicated by the feed flow differential pressure detector and as a backup the watt meter in the main generator output. In increasing power to the levels specified in the tabulation below the feedwater flow differential readings and watt meter readings as indicated below were not exceeded for specified power.

Final Appx. Power Level	F. W. Flow D/P Meter Reading	Watt Meter Reading
30%	(Obtained from Curve)	150 MWe
50%	(Obtained from Curve)	240 MWe
75%	(Obtain from Curve)	360 MWe
100%	(Obtain from Curve)	460 MWe

Once the nuclear instrument calibration data had been taken, the reactor power calculations were performed by feed flow, and by reactor and loop Delta T methods. Using the results of these calculations, the gain of the power range channel indicating closest to the calculated power by feedwater flow was adjusted. Following this gain adjustment, the gain of the other three channels was adjusted as necessary to match this channel. Prior to adjusting the gain of power range instruments, an examination of the flux maps and out-of-core flux (current) readings was made for the power at which the calorimetric data was taken, for any assymeterical flux pattern that could explain any difference in out-of-core indication.

Reactor power determined from Delta T measurements was used for informational purposes.

Reactor power was computed using loop and reactor Delta T measurements as follows:

Loop Delta T (Spare RTD's Th-Tc) Method

$$\%\ \text{Reactor Power} = \frac{\underline{\text{Full Design Flow}}\ \text{x}\ \underline{\text{Delta TA + Delta TB}}\text{)-Pnet heat}}{\begin{array}{l}\text{lbs/hr} \qquad\qquad\qquad 2 \qquad\qquad \underline{\text{gains X 100}} \\ \text{Full Design Power} \qquad \text{Btu/hr.}\end{array}}$$

$$= \frac{68.0 \times 10^6\text{/lbs/hr (Delta TA + Delta TB)-Pnet heat gains X 100}}{4437 \times 10^6\ \text{Btu/hr.}}$$

A plot of average power range detector current versus power to determine degree of linearity was made.

A plot of power range detector current versus detector voltage at near full power condition to determine operating voltage (twice voltage for 90% of saturated current condition) was made.

For each steady state power level for obtaining nuclear instrumentation calibration data, an in-core flux map was made.

An approximation of design reactor flow was computed using differential temperature measurement and reactor power as one means. Both loop and reactor differential temperatures were used in making these computations.

I. Excore Incore Calibration. RG&E S.U. 9.4

It was the function of the test to establish a relationship between incore and excore generated axial offset and delta flux.

The results of this test were later used to calibrate the upper and lower detector channels and to align the axial offset signals to the delta T setpoints.

With the part length control rods inducing an axial offset by virtue of their position in the core (10 steps from the bottom)

and with the plant electrical load maintained constant, a flux and thermocouple map was run under these conditions and the excore detector voltages were recorded periodically. This same procedure was followed with the part length rods located 85 and 160 steps out of core. Two more runs were made with bank D positioned on the bottom of the core as opposed to about 15 steps from the bottom as was the case in the first three runs.

This test was again run at 75% power to verify the channel settings and to further refine settings for extrapolation to 100% power.

This test did establish the fact that there was a fairly linear relationship between the incore and excore axial offset and a linear relationship between offset and power level.

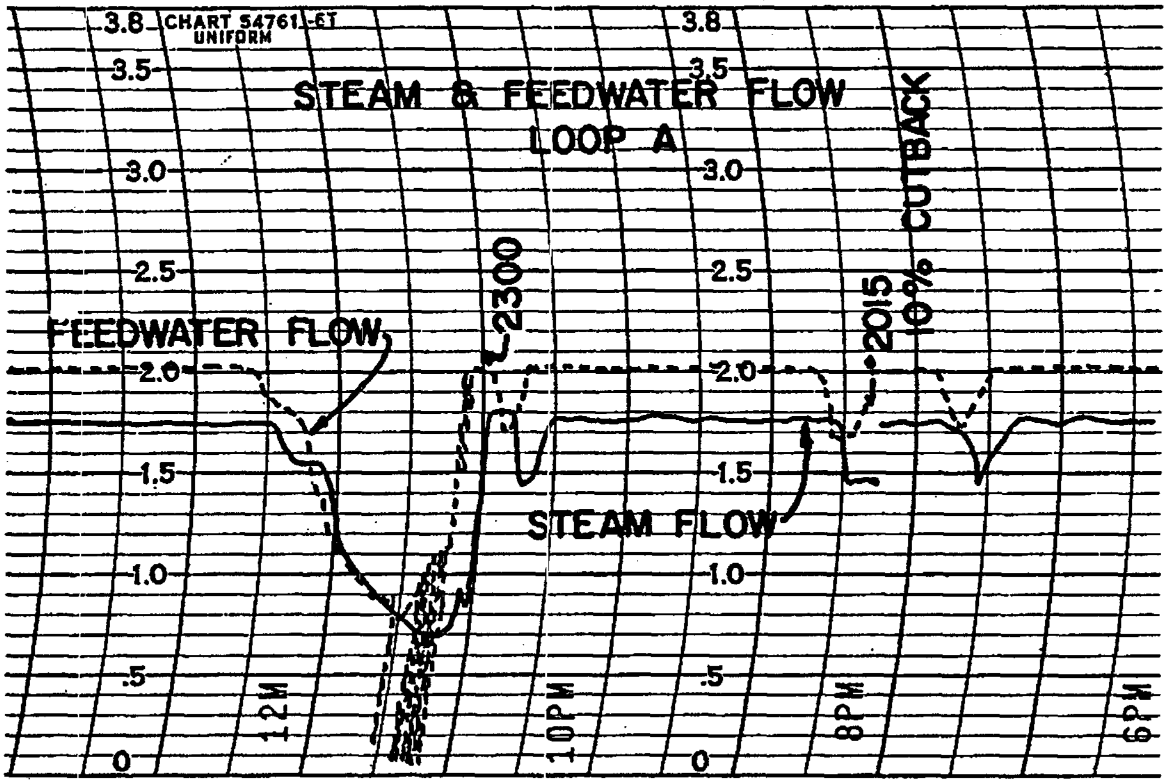


CHART 54761-6T UNIFORM
STEAM & FEEDWATER FLOW
LOOP A
FEEDWATER FLOW
STEAM FLOW
2300
2015
10% CUTBACK
3.8
3.5
3.0
2.5
2.0
1.5
1.0
.5
0
12M
10PM
8PM
6PM

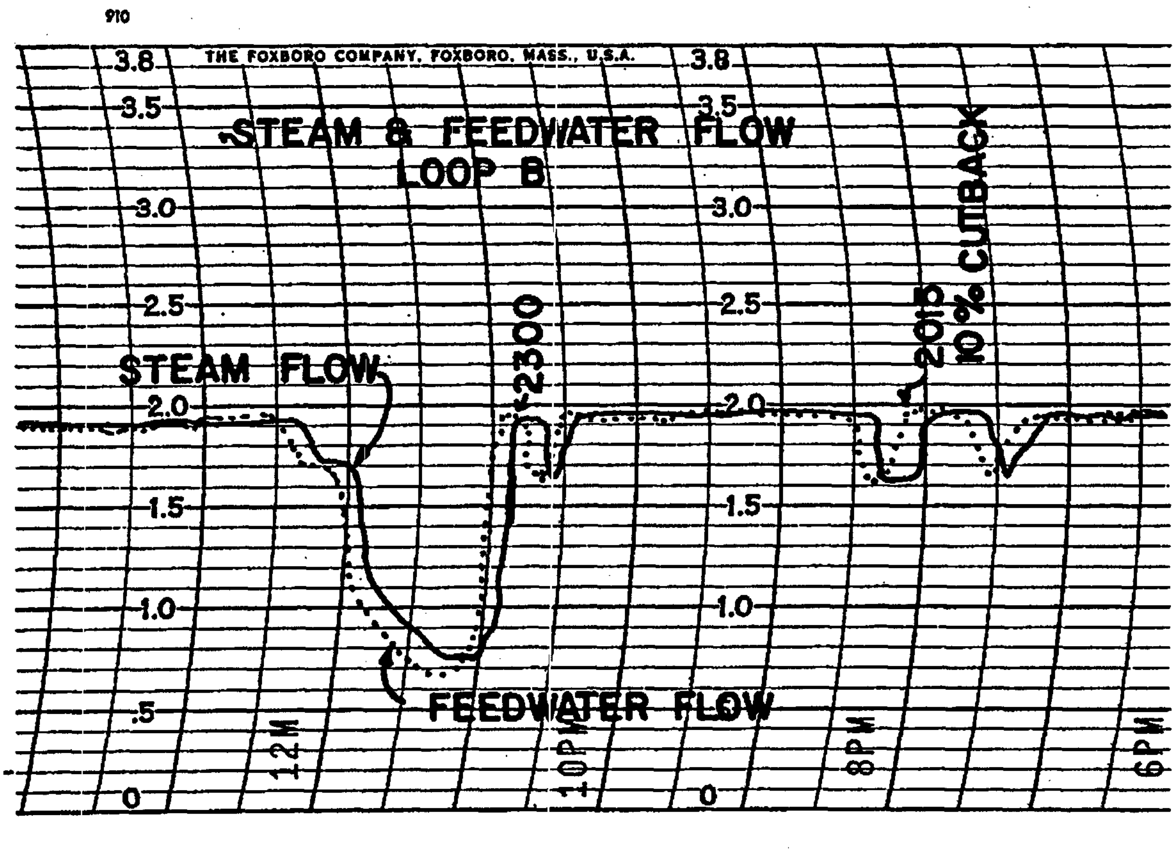

910
THE FOXBORO COMPANY, FOXBORO, MASS., U.S.A.
STEAM & FEEDWATER FLOW
LOOP B
STEAM FLOW
FEEDWATER FLOW
2300
2015
10% CUTBACK
3.8
3.5
3.0
2.5
2.0
1.5
1.0
.5
0
12M
10PM
8PM
6PM

Figure VII-1

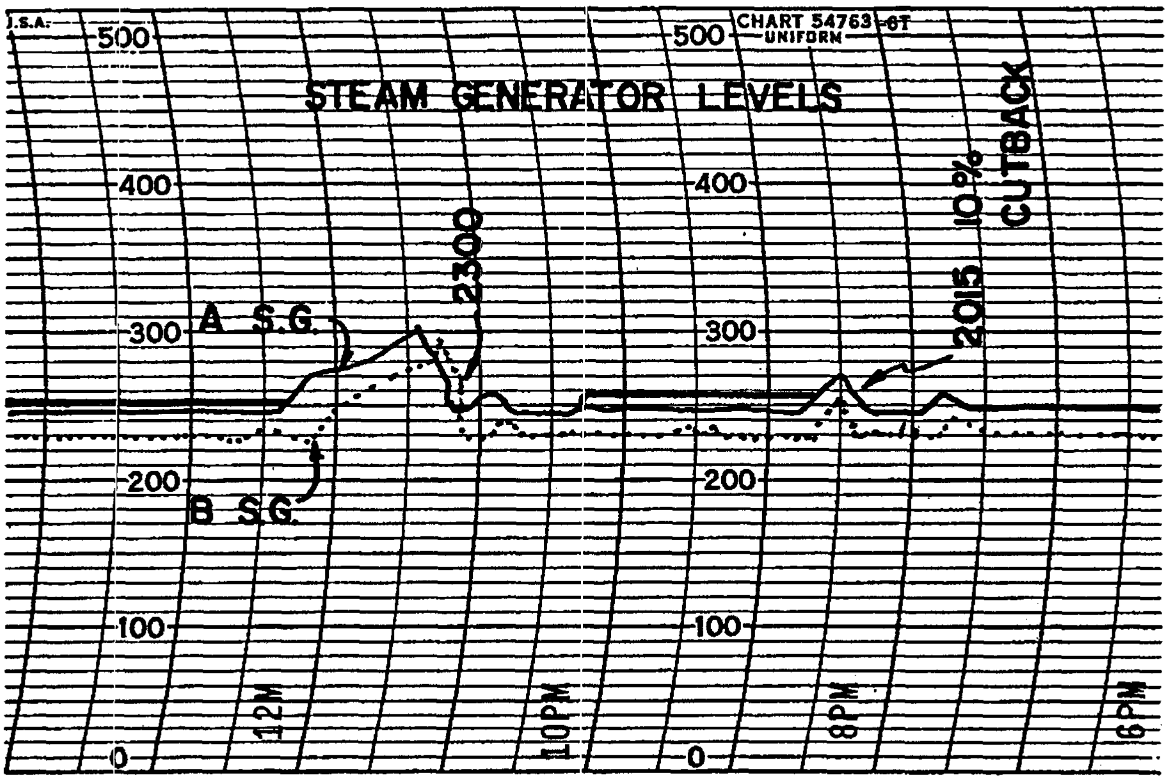


CHART 54763-6T
UNIFORM
STEAM GENERATOR LEVELS
500
400
300
200
100
0
A S.G.
B S.G.
2300
2015 10%
CUTBACK
12M
10PM
8PM
6PM

Figure VII-2

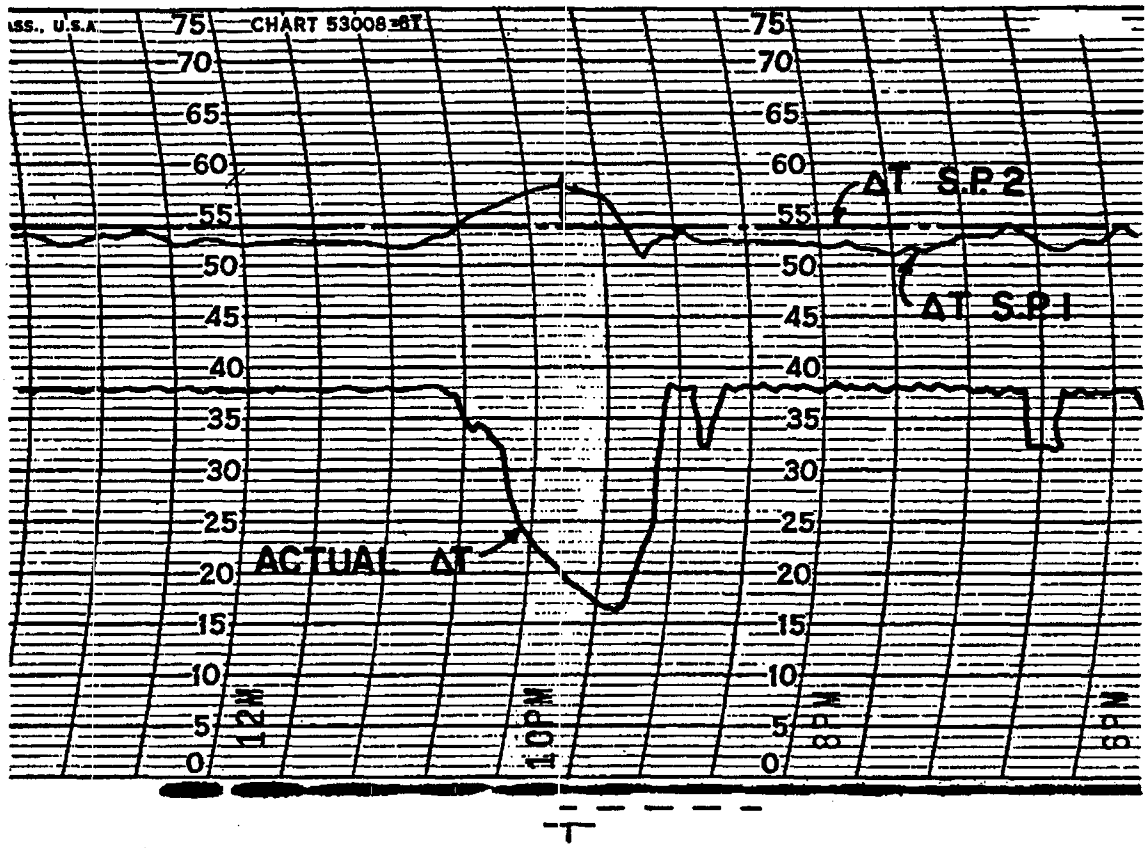


CHART 53008
ΔT S.P.2
ΔT S.P.1
ACTUAL ΔT
12 M
10 PM
8 PM
6 PM

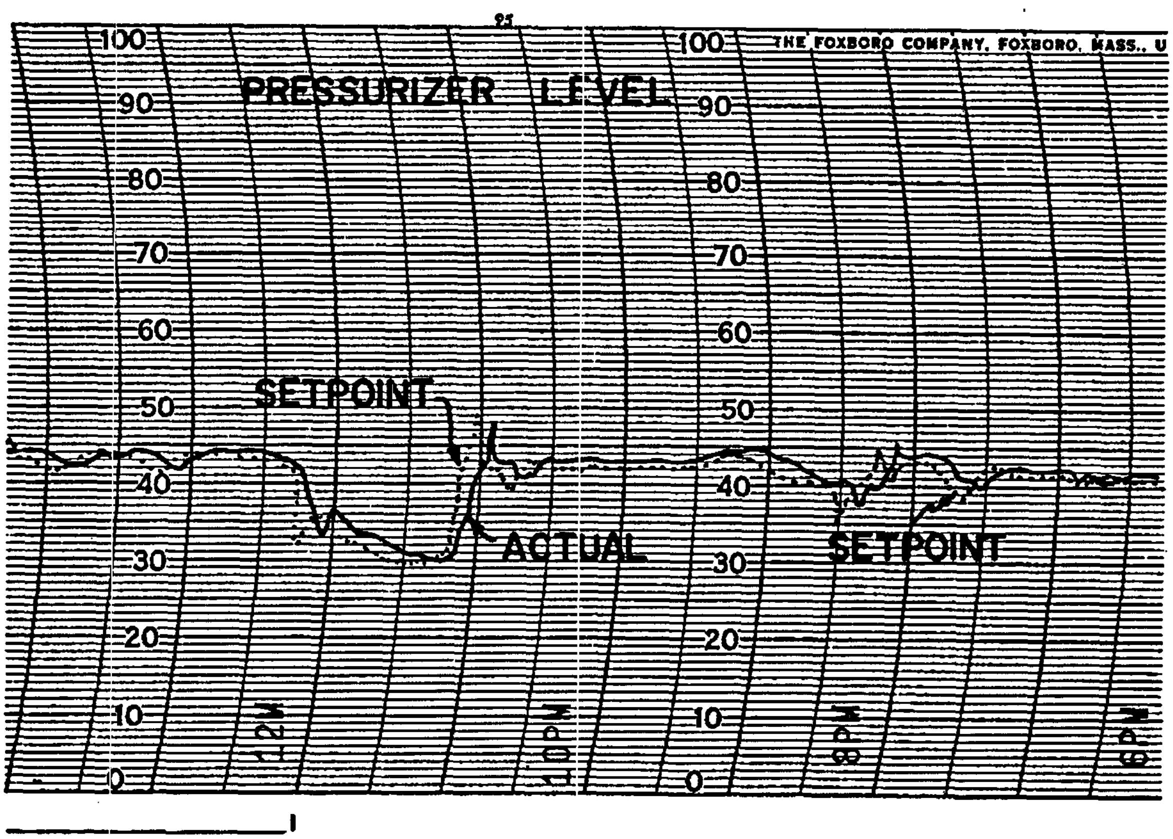
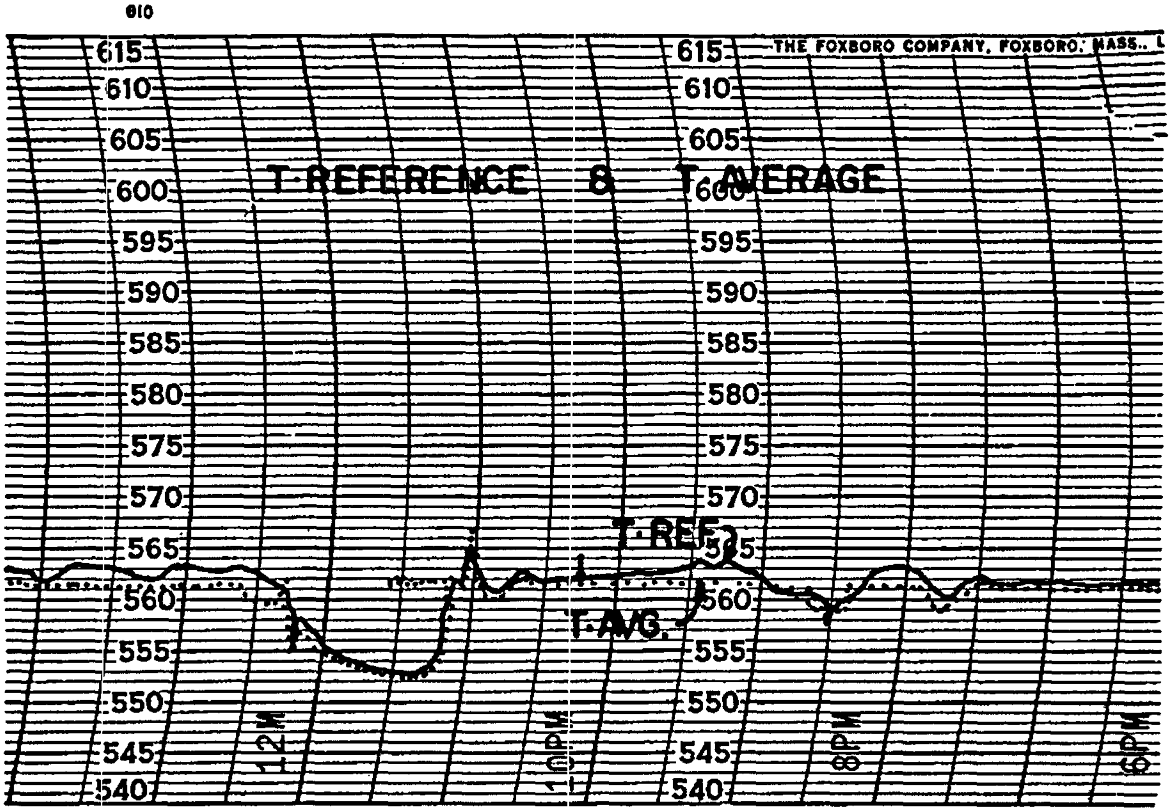

THE FOXBORO COMPANY, FOXBORO, MASS., U
PRESSURIZER LEVEL
SETPOINT
ACTUAL
SETPOINT
12 M
10 PM
8 PM
6 PM

Figure VII-3


010
THE FOXBORO COMPANY, FOXBORO, MASS.
T-REFERENCE & T-AVERAGE
T-REF.
T-AVG.
615
610
605
600
595
590
585
580
575
570
565
560
555
550
545
540
12 M
10 P M
8 P M
6 P M

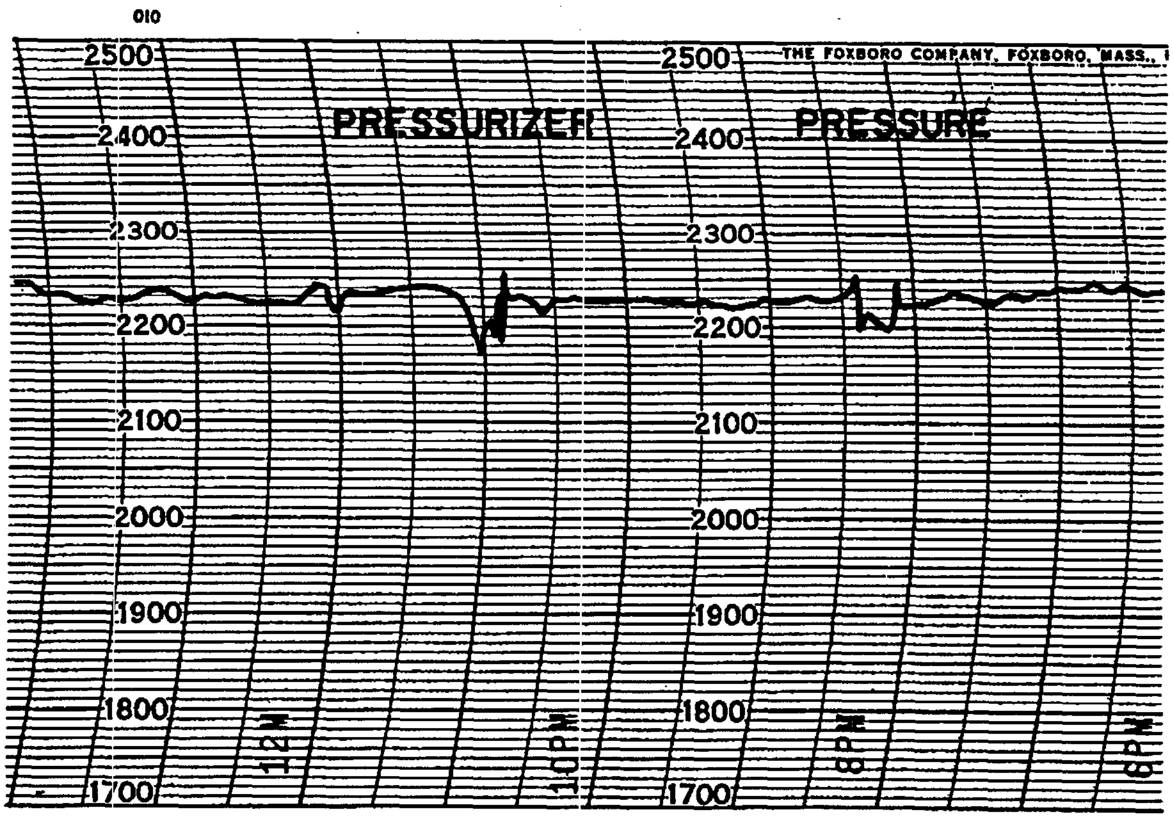

010
THE FOXBORO COMPANY, FOXBORO, MASS.
PRESSURIZER PRESSURE
2500
2400
2300
2200
2100
2000
1900
1800
1700
12 M
10 P M
8 P M
6 P M

Figure VII-4

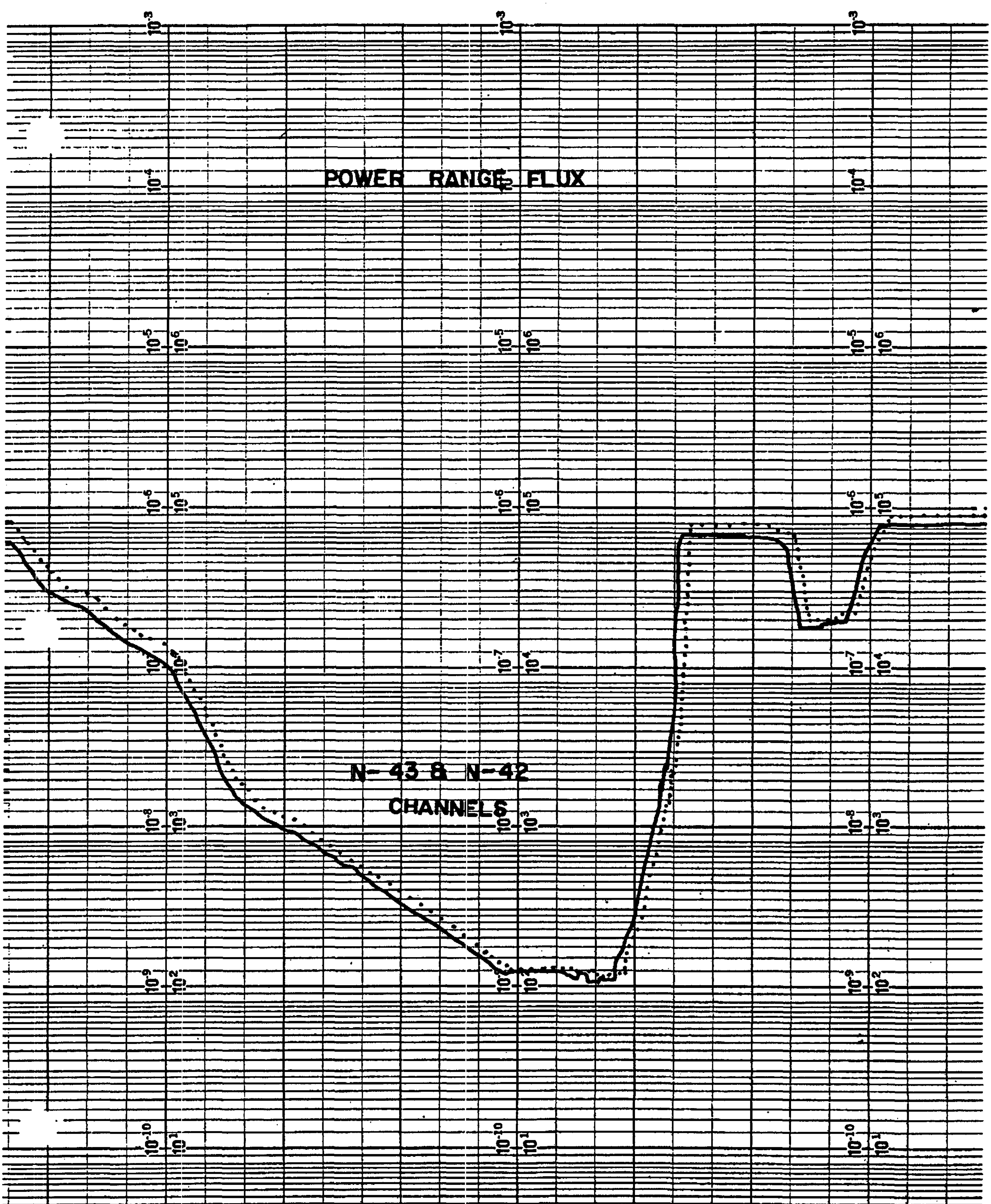
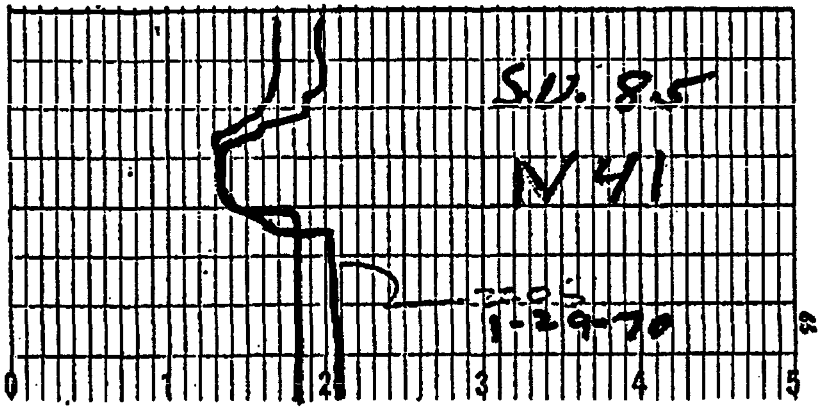
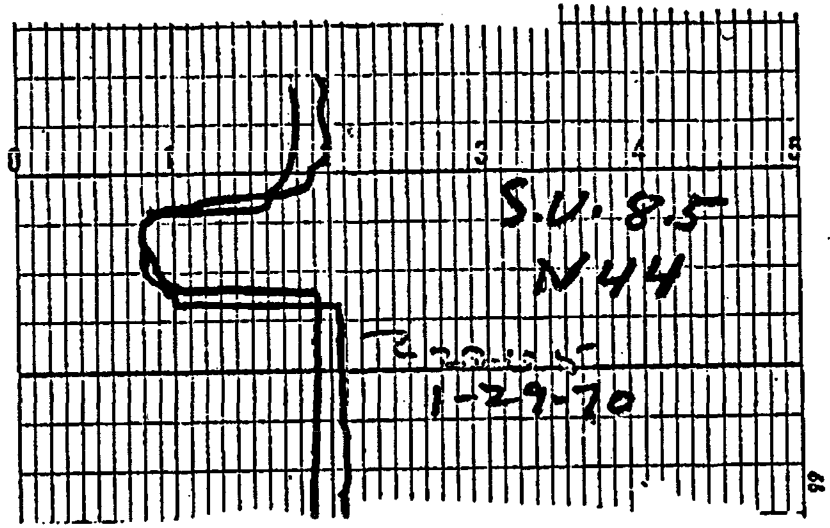
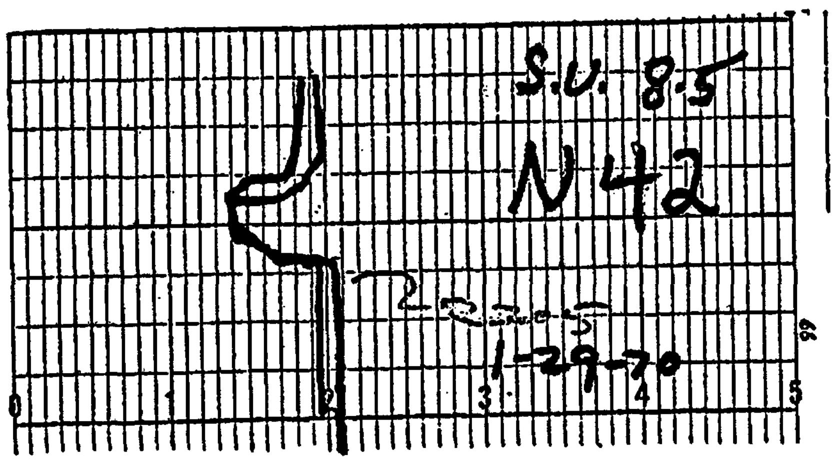

POWER RANGE FLUX
N-43 & N-42
CHANNELS
10^{-3}
10^{-4}
10^{-5} 10^{6}
10^{-6} 10^{5}
10^{-7} 10^{4}
10^{-8} 10^{3}
10^{-9} 10^{2}
10^{-10} 10^{1}

FIG. VII-5







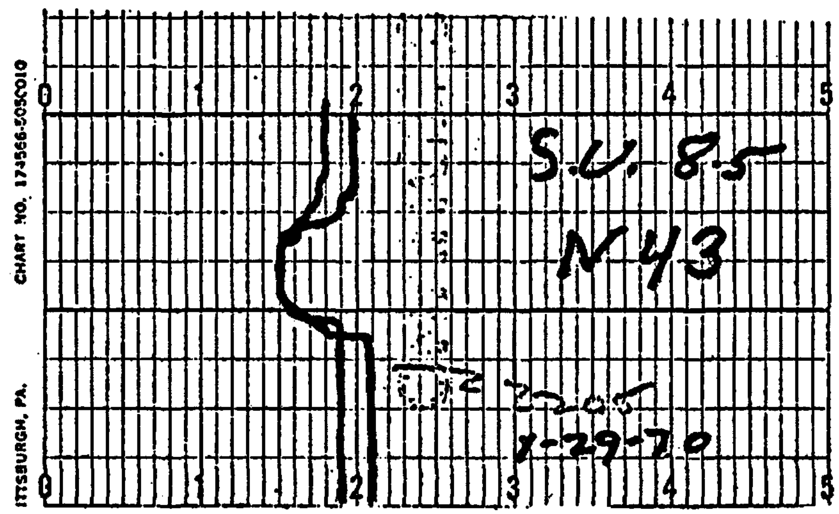


FIG VII-6

VIII. Startup Physics Testing

A. Introduction

An extensive physics testing program was conducted to see if the core reactivity characteristics and power peaking were close to design calculations and conservative with respect to assumptions used in the safety analysis. Measurements were made to determine:

1. Core reactivity parameters, including reactivity coefficients and control rod bank worths.
2. Power distributions, from zero to full power, with and without control rod bank insertion.
3. The effects of abnormal rod configurations, including individual rods fully withdrawn, fully inserted, and intermediate out-of-position configurations.
4. The adequacy of the excore instrumentation to monitor core performance for both normal and abnormal control rod configurations.

The conclusions drawn from the physics program results are:

1. The core performance is quite close to the design predictions.
2. The measured values for physics parameters required for safety analyses are less restrictive than the assumed values.

3. The core instrumentation system is successful in monitoring the core power distribution and sensing power asymmetry.

B. Power Distribution Measurements

The power distribution measurement results are documented separately in WCAP-7542-L, "Topical Report: Power Distribution Monitoring in the R. E. Ginna PWR." The responses of the excores, thermocouples, and incore movable detectors to both normal and abnormal power distributions are discussed.

C. Zero Power Critical Boron Concentrations

A summary of key reactivity measurements made during the initial physics tests is presented in Table VII. 1. These "zero power" measurements are in excellent agreement with predicted values with, perhaps, the exception of the "stuck rod configuration" which has all-rods-but-one inserted. The measured boron concentration is less than the predicted value, indicating the reactor has a greater total rod worth than predicted for the limiting stuck rod configuration.

D. Reactivity Coefficients and Shutdown Margin

In Table VIII. 2 the isothermal temperature coefficients are in good agreement with the predictions. It should be noted that

the positive coefficient does not exist with the normal rod configuration at zero power or at any other power level. This all-rods-out case was achieved only for the purpose of the test program and is specifically permitted by the Technical Specifications.

The measured Doppler coefficients shown in Table VIII. 2 are larger than predicted. The shutdown margin calculated from measured data is greater than the design value by roughly 0. 3% reactivity. The greater measured Doppler defect is overcome by the greater measured rod worth with one stuck rod for a small gain in shutdown margin.

E. Ejected and Dropped Rod Worths

The statically "ejected" and "dropped" rod worths are listed in Table VIII. 3. In the safety analyses, the ejected rod for the zero power case was assumed to be worth 1% reactivity. The measured value (0. 75% reactivity) shows this assumption is conservative. The measured ejected rod for the limiting full power configuration is 0. 30% reactivity, compared to 0. 365% assumed in the safety analysis. The measured power peaking factors (documented in WCAP-7542-L) for these two rod configurations are compared to the values assumed in the safety analyses at the bottom of Table VIII. 3.

The dropped rod reactivities presented in Table VIII. 3 are not directly related to any safety concern; no minimum or maximum limit is used in any safety or accident analysis in the FSAR.

F. Xenon Oscillation Test

An xenon oscillation test was performed to determine the dampening characteristics of the twelve foot core. The oscillation was induced by D bank insertion for four hours, then the D bank was withdrawn. The part length bank was held at the midplane throughout the test. The initial oscillation had the following characteristics:

Period	28 hours
Amplitude (t + 1/2 period)/Amplitude (t)	0.5

The oscillation was again induced, but axial symmetry was maintained using part length rod movement to counteract the xenon oscillation. The part length rods successfully held axial offset at 0%.

Table 8.1 Beginning of Cycle Zero Power Critical Boron Concentrations

Parameter	Measured	Predicted
Critical Boron (zero power, all rods out)	1608 ppm	1609 ppm
Critical Boron (zero power, Bank D in)	1526 ppm	1528 ppm
Critical Boron (zero power, Banks C and D in)	1365 ppm	1382 ppm
Critical Boron (zero power, Banks B, C and D in)	1253 ppm	1270 ppm
Critical Boron (zero power, PL at midplane)	1566 ppm	1566 ppm
Critical Boron (zero power, PL out, 28 rods in)	960 ± 25 ppm*	1015 ppm

* Inferred from subcritical state. Large uncertainty due to non-critical measurement.

Note: 10 ppm 100 pcm $\approx$ 0.1% reactivity

Table 8.2 Reactivity Coefficients and Shutdown Margin

	Measured	Predicted
Isothermal temperature coefficient		
(zero power, all rods out)	$+1.4 \times 10^{-5}/^{o}F$	$+1.2 \times 10^{-5}/^{o}F$
(zero power, D Bank inserted)	$-2.4 \times 10^{-5}/^{o}F$	$-1.9 \times 10^{-5}/^{o}F$
Doppler coefficient		
(10% power)	$-40 \times 10^{-5}/\%Q$	$-27 \times 10^{-5}/\%Q$
(30% power)	$-22 \times 10^{-5}/\%Q$	$-16 \times 10^{-5}/\%Q$
(85% power)	$-10 \times 10^{-5}/\%Q$	$-6.5 \times 10^{-5}/\%Q$
Doppler defect		
(50% power)	1.45%	1.00%
(100 % power)	2.03%	1.40%
Shutdown Margin		
Beginning of life	3.11 %	2.85 %
Estimated end of life	2.60%	2.27%

Table 8.3 <u>Ejected and Dropped Rod Worths</u>

Rod	of Bank	at	Worth, ppm	Bank Positions S	A	B	C	D	Power, %
Ejected Rods:									
K-7	D	230	75 (1)	230	175	5	5	5	0
K-7	D	230	30 (2)	230	230	230	230	20	30
G-11	D	230	29	230	230	230	230	20	30
K-7	D	230	8	230	230	230	230	153	30
J-10	C	230	20	230	230	230	107	22	30
K-7	D	230	38 (3)	230	230	230	107	22	30
G-7	C	230	18	230	230	230	107	22	30
Dropped Rods:									
G-7	C	0	45	230	230	230	230	20	30
K-9	S	0	33	230	230	230	230	20	30
G-7	C	0	23	230	230	230	230	180	30
I-7	B	0	22	230	230	230	230	167	30
J-10	C	0	20	230	230	230	230	169	30
F-12	A	0	20	230	230	230	230	149	30
K-7	D	0	10	230	230	230	230	141	30
K-9	S	0	18	230	230	230	230	153	30
I-7	B	0	40	230	230	230	230	22	30

Note: 10 ppm 100 pcm $\approx$ 0.1% reactivity

(1) FSAR Zero power assumed rod worth: 100 ppm F_q (measured) = 7.71 F_q (assumed) = 12.6

(2) FSAR full power assumed rod worth: 36 ppm F_q (measured) = 2.58 F_q (assumed) - 4.75

(3) C Bank insertion not permitted at full power. Position of C Bank corresponds to 40% power insertion limit

ROCHESTER GAS AND ELECTRIC CORPORATION

POWER ESCALATION TO 1520 MWt
March 1972

August 1972

Rochester Gas and Electric Corporation obtained a revised operating license for the R. E. Ginna Nuclear Power Station on March 1, 1972 which authorized an increase in the plant output from 1300 to 1520 MWt. A diverse and thorough testing program was used in the power escalation performed from March 8 to March 14, 1972. The objective of the program was to insure a well informed transition from 1300 to 1520 MWt. Core average burnup was 14,800 MWD/MTU.

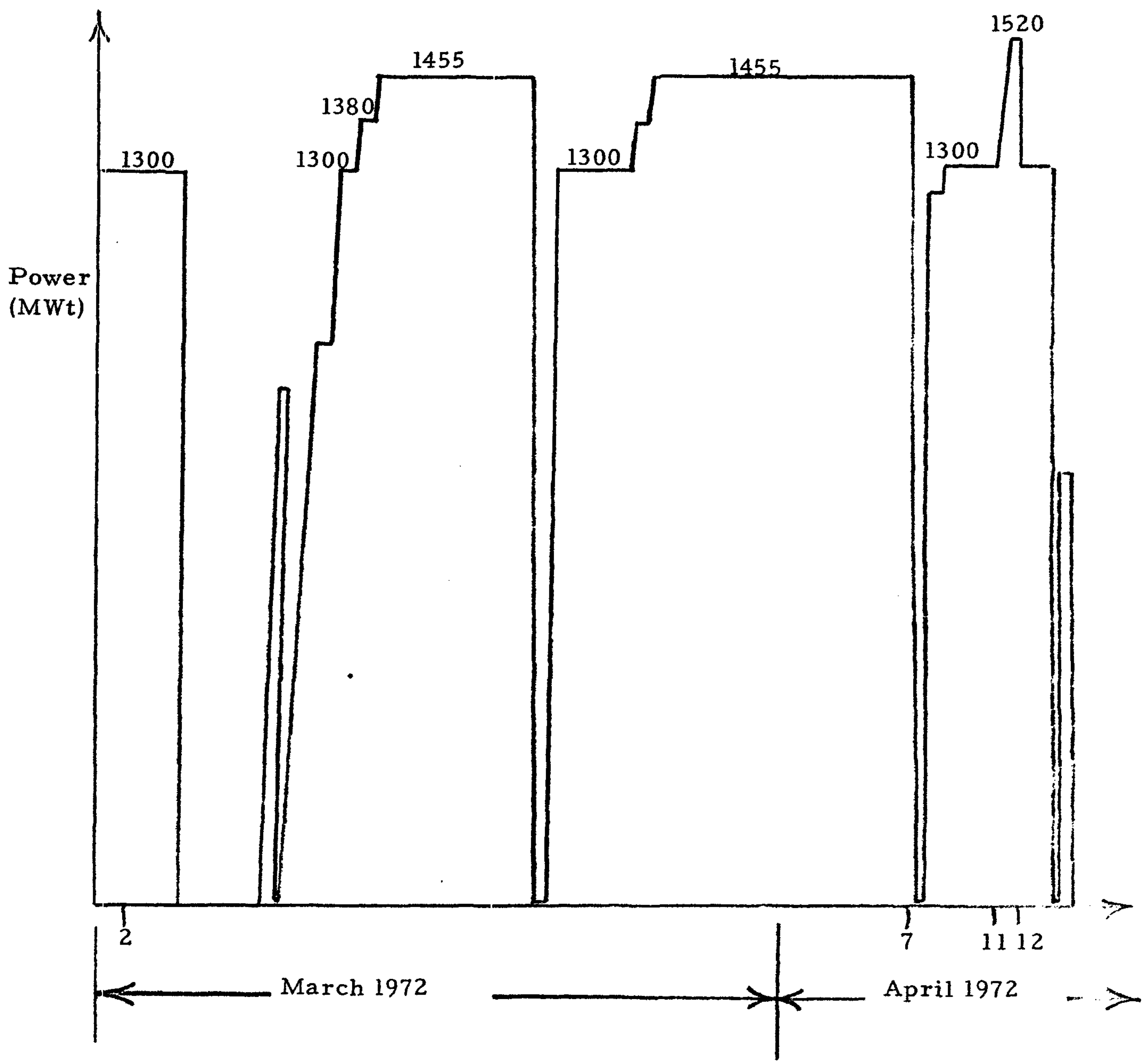
Figure 1 displays the reactor power level as a function of time for the period of interest. There were several distinct phases to the uprating program. Following a five day plant shutdown, a number of reactor physics parameters were measured at hot zero power. While these zero power tests were not a necessary portion of the testing program, the shutdown did afford an excellent opportunity for obtaining end-of-cycle physics data for use with nuclear design calculations.

At the completion of the zero power testing, the power escalation program was initiated. As can be seen in the figure, this escalation was comprised of several discrete steps, from 0 to 1300, from 1300 to 1380, from 1380 to 1455, and in mid-April to 1520 MWt. After each new power level was reached, a number of tests and measurements were performed. These included flux and delta-T measurements, containment vessel radiation surveys, and primary coolant activity level measurements. Data obtained at each power level were reduced and evaluated before the core power was

FIGURE 1

POWER HISTORY: MARCH 1 - APRIL 15, 1972

The dates shown on the abscissa correspond to coolant activity samples discussed in detail in this report.



increased. In addition, careful attention was paid to system components during all phases of the escalation program.

As power was increased to 1300 MWt, the power coefficient was measured and the power defect obtained. A review of test results at 1300 MWt, including a detailed check of the flux map results showed good agreement with the expected data. Data obtained at 1380 MWt also displayed this good agreement with predictions, thus justifying a further power increase to 1455 MWt. As well as the tests outlined above, additional flux maps were obtained at 1455 MWt to facilitate the generation of the axial offset f(ΔI) set points for operation at 1520 MWt.

Two phenomena caused further power escalation to be postponed. A higher than expected primary coolant activity was encountered and steam-line vibration was noted. The results of all other tests were favorable and indicated that power could be raised to 1520 MWt.

On April 12, 1972, shortly before the Cycle 1B refueling shutdown, core power was increased to 1520 MWt for approximately six hours. The escalation from 1300 MWt proceeded at 1% power per hour and followed four days operation at 1300 MWt for primary coolant activity cleanup. Plant improvements had been implemented to remedy the steam line vibration problem. The purpose of the operation at 1520 MWt was to test the secondary system at 1520 before the annual maintenance period and to test the fuel prior to conducting the fuel inspection. After completing all tests outlined above, the reactor was returned to 1300 MWt.

Testing performed during the power escalation program demonstrated that the plant can be operated at 1520 MWt. Core flux and delta-T maps showed that, as expected, there is very little change in assembly relative power levels as core power is raised from 1300 to 1520 MWt. Margins to the core safety limits remained large. For example, the measured peak F_Q^N, including a 5% measurement uncertainty, was 1.63. This may be compared with the Technical Specification limit of 2.72. One reason for the low measured value is, of course, that a full cycle of depletion had taken place; peaking factors are expected to be largest at the beginning of a cycle.

The containment radiation surveys did not reveal any unexpected increases in radiation levels during or following the escalation program. The primary coolant radioactivity levels did, however, increase more rapidly than expected particularly for the shorter-lived isotope such as Xe-135, Kr-87, and Kr-88. The effect of the power escalation on fuel rod integrity can best be analyzed by comparing primary coolant activity following equilibrium operation at 1300 MWt prior to early March with the activity at 1300 MWt in early April. These data indicate that some additional fuel rods probably failed between early March and early April. The data obtained at 1520 MWt cannot be evaluated in this fashion since several days operation at a given power level is required to reach equilibrium coolant activity conditions. The small increase in coolant activity noted

at 1520 MWt compared to the 1300 MWt levels does indicate the beneficial effect on coolant activity of increasing power level slowly.

Steam generator moisture carryover met the warranted values.

A comprehensive testing program was established and followed to insure an orderly power escalation. Care was taken to evaluate all available information before proceeding to new power levels greater than 1300 MWt. This care insured that a safe and well documented program was carried out which resulted in demonstrating that the core could be operated at 1520 MWt.

STEAM GENERATOR MOISTURE CARRYOVER

Steam generator moisture carryover tests were performed at each power level during the uprating test program and at 1520 MWt in April. The results of these tests are listed in the following table.

Power	Date	% Carryover
1300	3-11-1972	.02
1380	3-12-1972	.052
1455	3-13-1972	.21
1455	3-14-1972	.22
1520	4-12-1972	.519

The moisture carryover met the .25% requirement at the warranted power level of 1455 MWt.

ASSEMBLY DELTA-T MEASUREMENTS

In conjunction with each flux-map, a complete set of assembly temperature rise measurements was taken. Before proceeding to a new power level above 1300 MWt, the last set of thermocouple data was extrapolated to the new power based on the power increase and on the expected assembly relative powers. While the temperature measurements are not as accurate as the flux measurements, they do provide a quick check of the assembly power levels. In general, the measured assembly exit temperatures were within 1°F of the expected values. (The temperature rise through the core at 1520 MWt is approximately 58°F). In the few cases where the differences were larger than 1°F, the flux maps insured that the assembly power levels were as expected.

PLANT RADIATION SURVEYS

Radiation surveys were made throughout the plant with portable survey instruments during the power escalation program. Gamma and neutron radiation levels were measured at a number of points on the operating floor, the intermediate floor and the basement of the containment vessel. The measurements give a rough estimate of the radiation levels in the containment. Accuracy of the measurements is limited since surveys at different power levels were taken by different people, since a constant counting geometry could not be maintained at each survey station, and since the high radiation levels gave only a short time in which measurements could be made. In addition, non-equilibrium effects and the changes in waste treatment system flow rates could introduce errors into the measurement.

It is expected that the neutron radiation levels would be proportional to the power. The gamma radiation level should not, however, be proportional to power since it depends on waste treatment. A summary of the data is presented in Table 1. The values listed in the table for radiation increase refer to the average of the surveys taken at a particular power level and are related to the average obtained at 1300 MWt.

TABLE 1

Average Increase in Containment Radiation Levels During Uprating Program

Date	3/11/72	3/12/72	3/13/72	4/12/72
Reactor Power (MWt)	1300	1380	1455	1520
% Increase	0	6.1	11.9	17.
Neutron Radiation % Increase	0	6.2	2.4	23.
Gamma Radiation % Increase	0	4.0	6.5	18.

REACTOR PHYSICS MEASUREMENTS

Zero Power Measurements

Following the scheduled five day shutdown prior to the uprating program and while at a nominal hot zero power level, a number of reactor physics measurements were performed. The results are primarily of benefit in reactor design and development and were not an important facet of the uprating program. These tests included:

Critical boron concentration - all rods out
Isothermal temperature coefficient - all rods out
Bank D differential and integral worth

Critical boron concentration - Bank D inserted
Isothermal temperature coefficient - Bank D inserted
Bank C differential and integral worth (Bank D inserted)

Critical boron concentration - Banks C and D inserted
Isothermal temperature coefficient - Banks C and D inserted

Basic results of the measurements are reported in Table 2.

The worths of bank D and of bank C are less than those predicted and measured at the beginning of Cycle 1B. This might be expected since the relative power in the rodded assemblies decreased during the cycle. The plots of integral and differential worth for banks D and C are presented in Figures 2 and 3, respectively.

TABLE 2

SUMMARY OF MEASURED PARAMETERS AT HOT ZERO POWER PRIOR TO RGE UPRATING

Parameter	Measured Value
Control Bank Integral Worth (pcm)	
Bank D	839
Bank C	1176
Critical Boron Concentrations (ppm)	
All Rods Out	616
Bank D in	535
Banks C & D in	425
Boron Worth (pcm/ppm)	-10.7
Temperature Coefficients (pcm/°F)	
All Rods Out (548 ± 3°F, 616 ppm boron)	-13.9 ± .4
Bank D inserted (550 ± 3°F, 532 ppm)	-14.8 ± .2
Banks C & D inserted (547 ± 2°F, 422 ppm)	-18.1 ± .1

FIGURE 2
RG&E UPRATING
CONTROL BANK D DIFFERENTIAL & INTEGRAL WORTH
CYCLE 1B 7800 MWD/MTU
HOT ZERO POWER

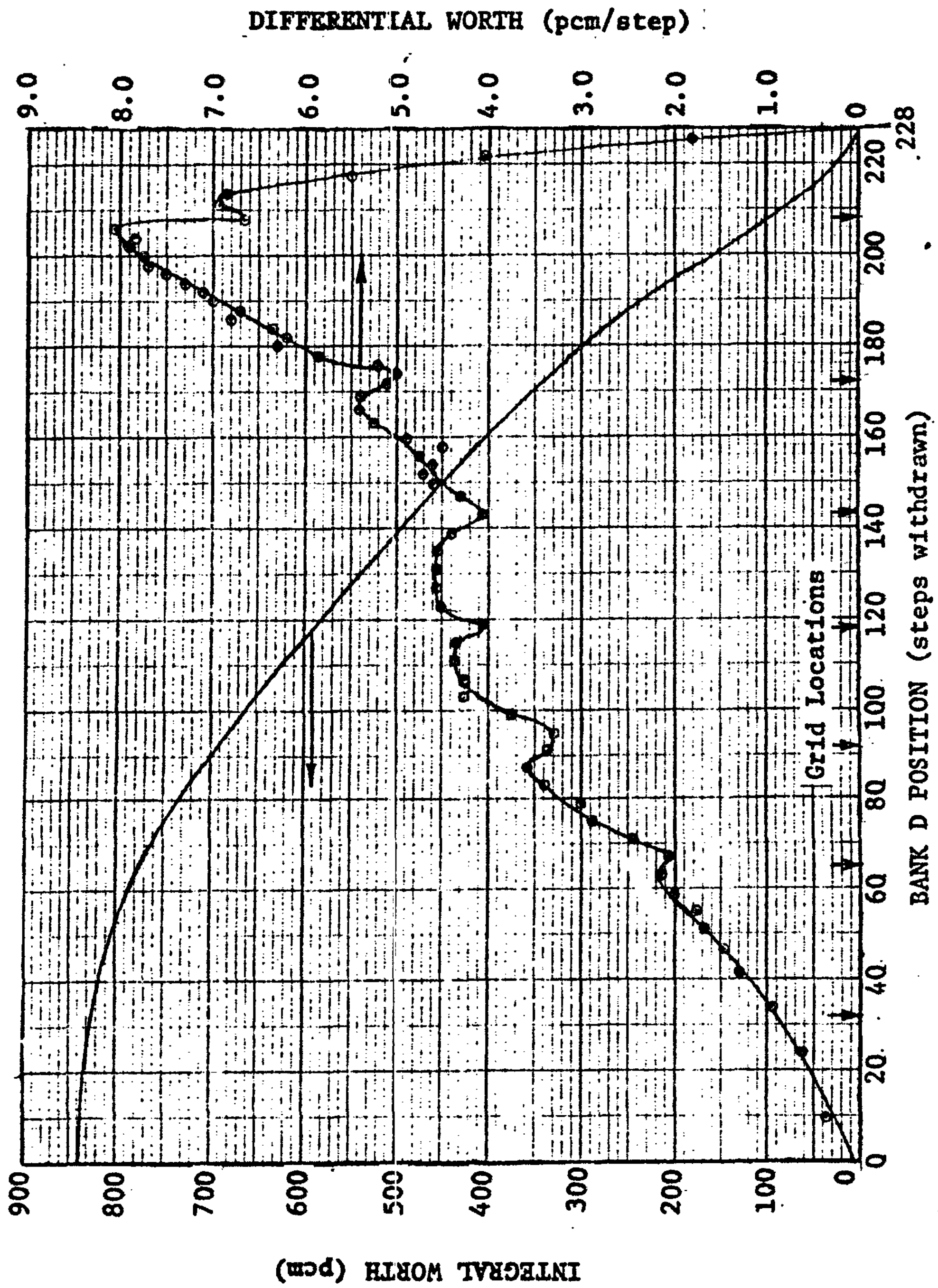


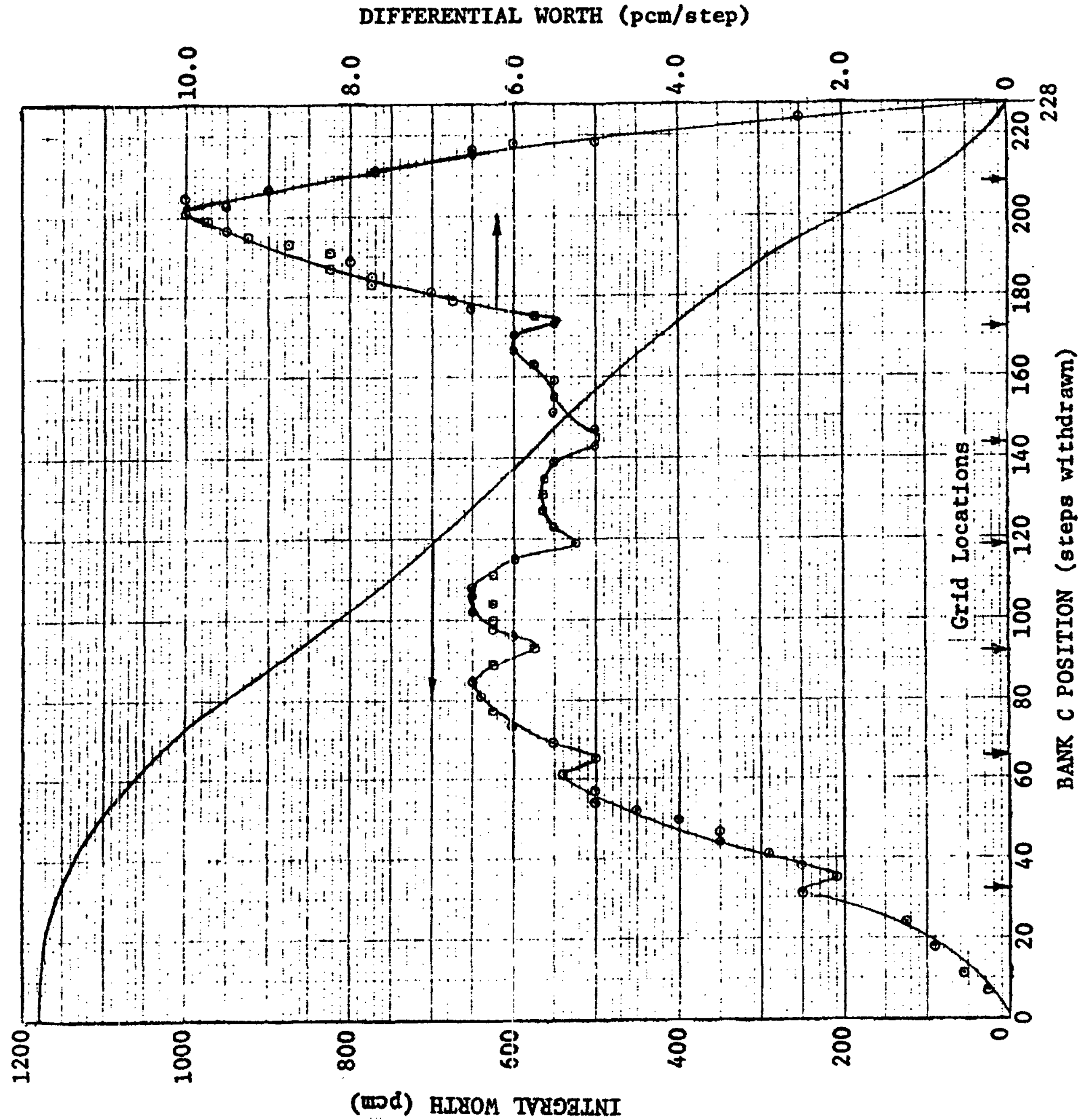
FIGURE 3

RG&E UPRATING

CONTROL BANK C DIFFERENTIAL & INTEGRAL WORTH

CYCLE 1B 7800 MWD/MTU

HOT ZERO POWER

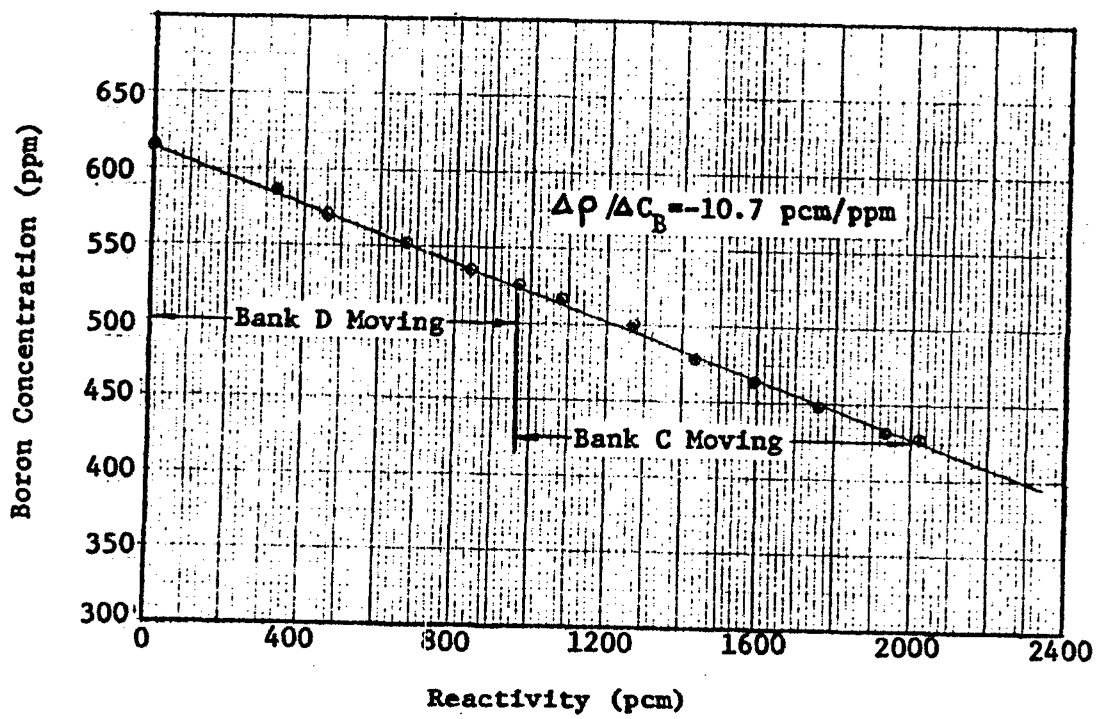


The isothermal temperature coefficient was obtained as a function of boron concentration by taking measurements of several different control rod insertion configurations. At a given rod configuration, the moderator temperature was varied about a nominal value to obtain the reactivity effect of such a change. The isothermal temperature coefficient was found to be a non-linear function of the boron concentration, as can be seen in Figure 4. Non-linear behavior was expected based on the curves presented in Section 3. 2. 1 of the FSAR. The non-linearity may have been due in part to the different control rod configurations employed. The changes seen in the nominal moderator temperature may have contributed to the non-linearity due to the effect on the neutron diffusion length as a result of changing moderator density. The data at 616 and at 532 ppm of boron are about 10% less negative than predicted for the end-of-life by the Cycle 1B design report while the value at 422 ppm agrees well with the prediction.

At-Power Measurements

Upon conclusion of the zero power measurements, reactor power was increased to 1300 MWt in several steps. During this increase, the power defect was measured. The integral power defect (doppler, moderator temperature, and flux redistribution) from zero to 1300 MWt was measured to be 1.33% $\Delta\rho$ at the critical boron concentration of 420 ppm. The reactivity defect due to doppler and flux redistribution was obtained by

FIGURE 4
RG&E UPRATING
BORON CONCENTRATION vs. REACTIVITY INSERTION
(Boron Dilution)
CYCLE 1B 7800 MWD/MTU
HOT ZERO POWER



removing the reactivity effect of increasing the moderator T_{avg} and was found to be 1.00% $\Delta\rho$ from zero to 1300 MWt. The values predicted at the end-of-life for the doppler defect and the power defect (not including flux redistribution) are approximately 1.18 and 1.70 $\Delta\rho$, respectively.

After correcting the data for variation in moderator temperature and xenon redistribution, the power coefficient as a function of power was obtained. These data are plotted in Figure 5. Data were not obtained between 1300 and 1520 MWt because it was decided not to subject the core to the rapid transient which would have been necessary. Power transients have been found to result in a temporary increase in primary coolant activity.

Upon reaching 1300 MWt, the main portion of the uprating tests began. The intent was to take core maps at 1300, 1380, 1455, and 1520 MWt. Each map was to be analyzed before proceeding to a higher power level. At 1300 MWt, a reference flux map (#93) was taken to serve as a basis for evaluation of the power distribution obtained at higher power levels. Excellent agreement was found between the measurements and the predicted power distributions.

A flux map was taken at 1380 MWt and three maps, for use in the f(Δ I) set point calibration, were taken at 1455 MWt. Selected system parameters for these maps are given in Table 3.

FIGURE 5

RG&E UPRATING
ISOTHERMAL TEMPERATURE COEFFICIENT
vs. BORON CONCENTRATION
CYCLE 1B 7800 MWD/MTU
HOT ZERO POWER

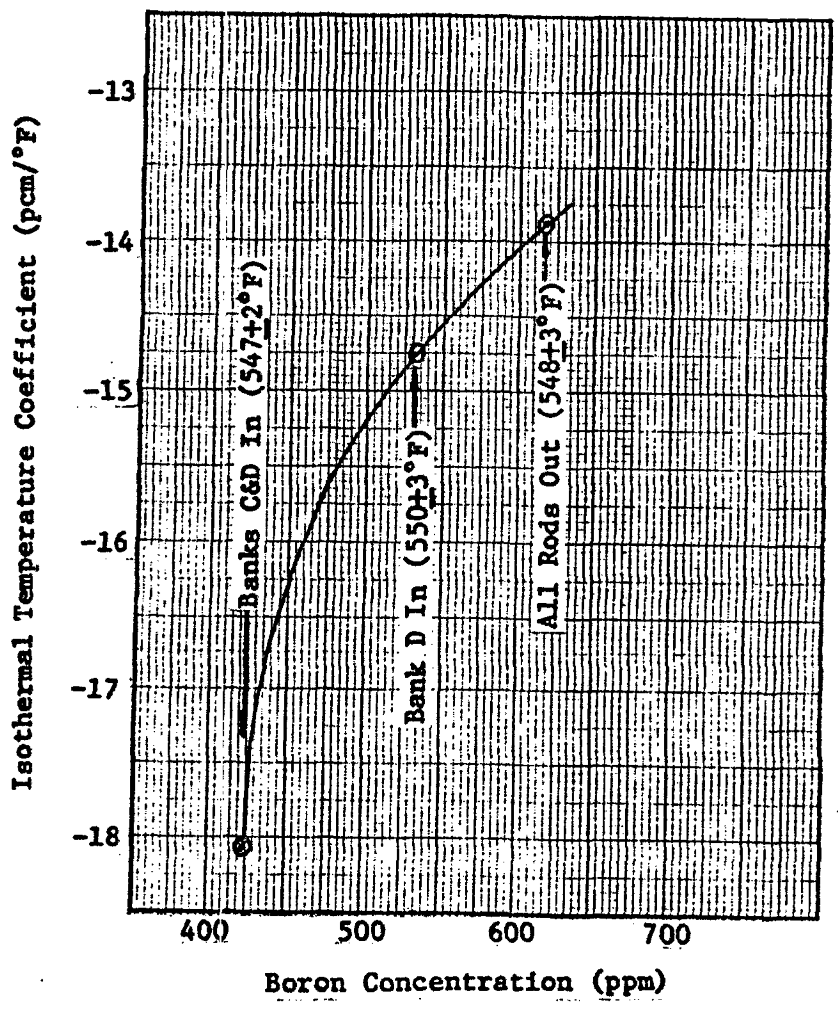


TABLE 3

Selected Data for Flux Maps

Map	Power	Measured Axial Offset	Rod Position D	Rod Position P/L
93	1300	+ 0.6%	213	83
94	1380	- 3.1%	210	75
95	1455	- 0.6%	211	67
96	1455	-11.1%	211	84
97	1455	+10.3%	212	33

In all cases, the agreement between measured and predicted power distributions was very good. Differences were typically less than 3%. The relative power distributions symmetry at 1300 MWt, 1380 MWt, and 1455 MWt are shown in Figure 6. For ease of presentation, the values listed in the figures represent the average for the four quadrants. These data demonstrated that the power distributions were well behaved and that there were no unexpected hot assemblies.

The assembly relative power distributions for the three flux maps taken at 1455 MWt are given in Figure 7. There are no major differences in the assembly power distributions of these three maps and the measurements agree well with the predictions from PDQ calculations.

The power range detector output was monitored as a function of core power. In Figure 8, the output of excore detector NE-41 (sum of the top and bottom detectors) is plotted as a function of core power and a linear correlation is seen. A similar linear correlation was seen for detectors NE-42, NE-43, and NE-44. The correlation between excore detector response and the axial offset as calculated from the flux map data is presented in Figure 9 for detector NE-41. The linearity of detector response with axial offset was also found in the other three excore detectors. This linearity demonstrates that the detectors continue to accurately monitor core axial offset and that the data obtained at 1455 MWt may be used to generate the f(ΔI) set points for operation at 1520 MWt.

Figure 6

ROCHESTER GAS AND ELECTRIC CORPORATION

Relative Power During Uprating:
1300, 1380, 1455 MWt

1.12 1.12 1.12	1.13 1.13 1.13	1.11 1.12 1.12	1.20 1.21 1.21	1.11 1.13 1.12 D	1.04 1.05 1.05	.82 .82 .82
1.14 1.15 1.15	1.17 1.18 1.17	1.11 1.10 1.11	1.10 1.10 1.11	1.08 1.09 1.09	1.17 1.18 1.18	.66 .66 .66
1.14 1.15 1.15	1.11 1.12 1.11	1.05 1.04 1.03 P/L	1.13 1.13 1.13	1.08 1.08 1.07	.90 .90 .90	
1.22 1.22 1.22	1.11 1.11 1.11	1.14 1.13 1.13	1.03 1.02 1.02	.93 .93 .93	.60 .60 .60	
1.13 1.13 1.12 D	1.09 1.08 1.08	1.10 1.08 1.08	.94 .93 .94	.66 .66 .67		
1.06 1.03 1.04	1.18 1.16 1.17	.92 .90 .90	.61 .61 .61			
.84 .82 .82	.67 .65 .66					

Core Power = 1300 MWt
1380 MWt
1455 MWt

Power	Map No.	Axial Offset	Rod D	Position P/L
1300	93	+0.6%	213	83
1380	94	-3.1%	210	75
1455	95	-0.6%	211	67

Figure 7

ROCHESTER GAS AND ELECTRIC CORPORATION

Relative Power During Uprating:
1455 MWt

1.12 1.12 1.10	1.13 1.13 1.11	1.12 1.12 1.11	1.20 1.21 1.20	1.11 1.13 1.11 D	1.04 1.05 1.05	.82 .82 .84
1.15 1.15 1.16	1.18 1.18 1.17	1.11 1.10 1.11	1.10 1.10 1.10	1.08 1.09 1.08	1.17 1.18 1.18	.66 .66 .67
1.15 1.15 1.15	1.12 1.12 1.11	1.05 1.04 1.06 P/L	1.13 1.13 1.14	1.08 1.08 1.09	.90 .90 .93	
1.22 1.22 1.22	1.11 1.11 1.11	1.13 1.13 1.12	1.02 1.02 1.03	.93 .93 .93	.60 .60 .60	
1.12 1.13 1.12 D	1.08 1.08 1.07	1.08 1.08 1.07	.93 .93 .94	.66 .66 .66		
1.04 1.03 1.03	1.17 1.16 1.16	.90 .90 .90	.61 .61 .61			
.82 .82 .79	.66 .65 .66					

Nominal Axial Offset = -10%
0%
+10%

Map No.	Rod Position D	Rod Position P/L	Axial Offset
95	211	67	- 0.6%
96	211	84	-11.1%
97	212	33	+10.3%

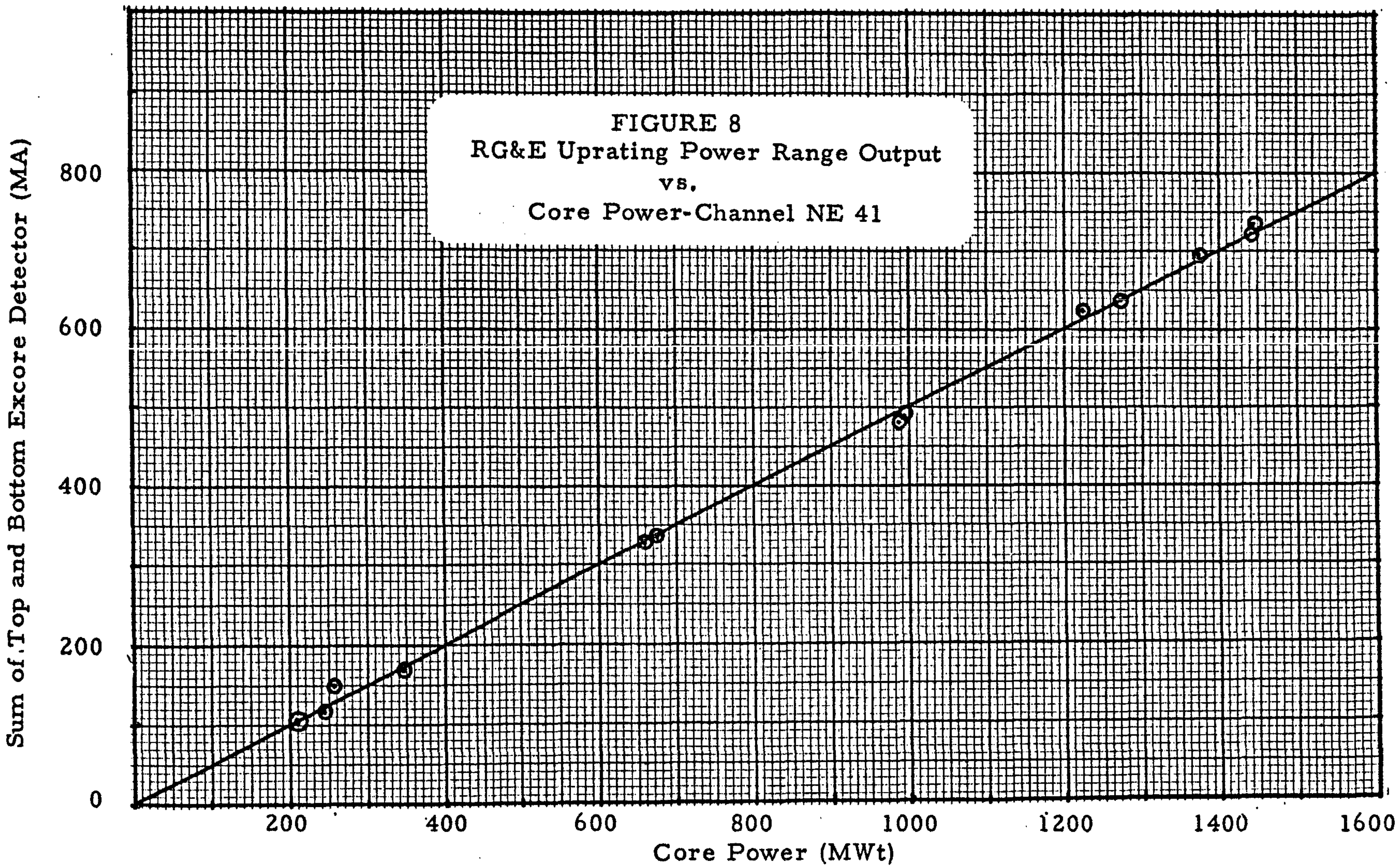


FIGURE 8
RG&E Uprating Power Range Output
vs.
Core Power-Channel NE 41
Sum of Top and Bottom Excore Detector (MA)
0
200
400
600
800
200
400
600
800
1000
1200
1400
1600
Core Power (MWt)

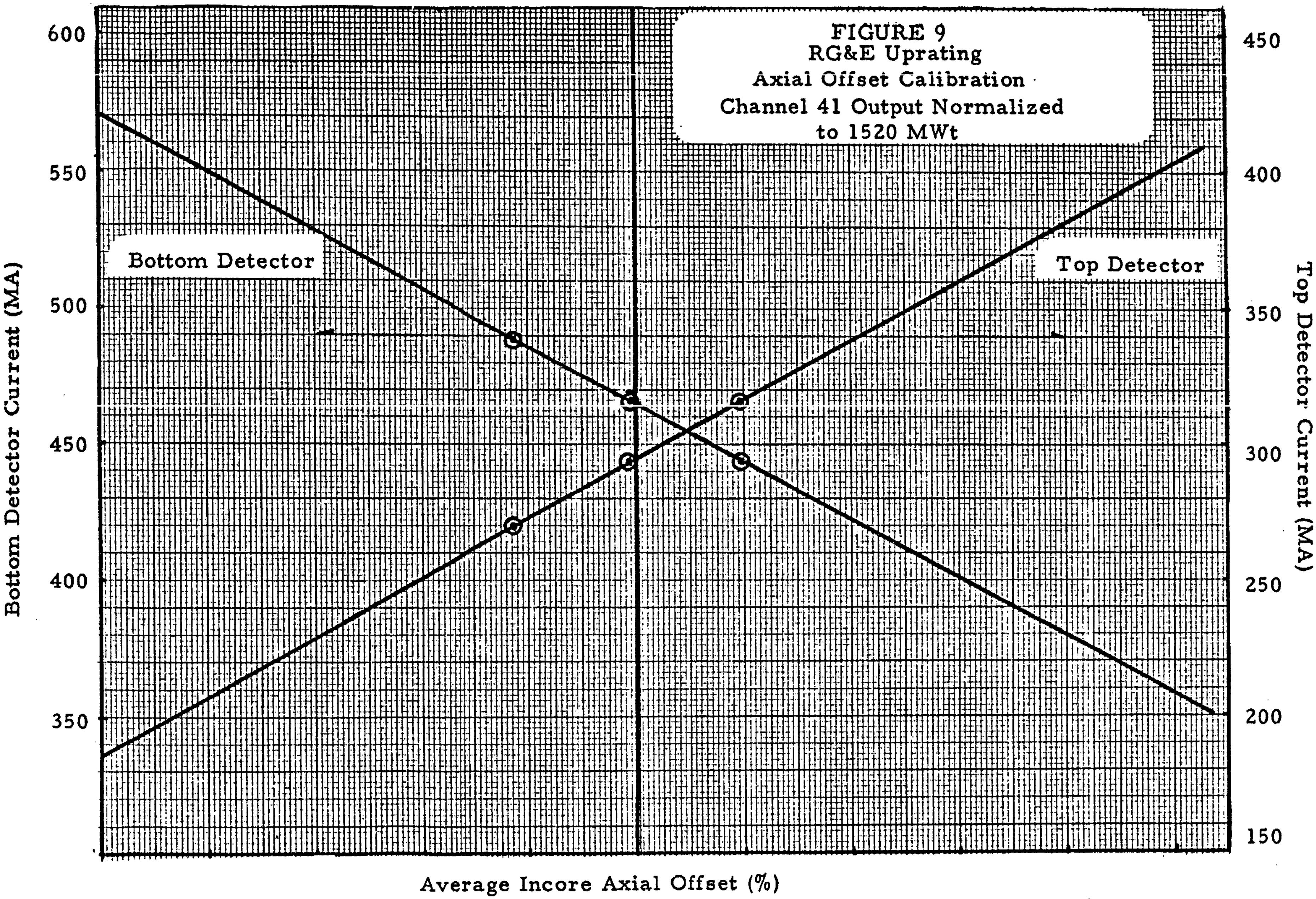


FIGURE 9
RG&E Uprating
Axial Offset Calibration
Channel 41 Output Normalized
to 1520 MWt

The power escalation program was halted at 1455 MWt due to high coolant activity and steam line vibration. On April 12, the reactor was taken to 1520 MWt for a period of six hours so that system component behavior might be determined before the mid-April refueling. A core flux map was taken during the operation at 1520 and the results of that map are presented in Figure 10. The assembly relative powers cannot be directly compared with the earlier maps in the uprating program since the part-length rods were withdrawn from the core prior to increasing power to 1520 MWt. The difference between measurement and prediction was, typically, less than 2%.

Figure 10

ROCHESTER GAS AND ELECTRIC CORPORATION

Relative Power at 1520 MWt
April 12, 1972

1.12	1.13	1.13	1.20	1.10 D	1.01	.80
1.15	1.20	1.15	1.12	1.06	1.13	.64
1.16	1.15	1.19 P/L	1.17	1.12	.90	
1.22	1.12	1.16	1.03	.92	.59	
1.10 D	1.06	1.07	.91	.64		
1.00	1.13	.88	.59	Measured		
.77	.63					

Map No.	D Bank	P/L	Axial Offset
99	210	Out	-8.8%

PRIMARY COOLANT ACTIVITY

Sampling

Primary coolant chemistry samples were drawn daily during the power escalation program and more frequently following power transients. Isotopic analyses were performed on the samples to determine the abundance of the various fission products in the coolant. The energy-weighted activity was calculated for comparison to the Technical Specification limit and individual isotopic activities were tracked to determine the effects of increased power and/or fuel cladding defects on activity.

Activity Before the Uprating

Table 4 shows the trend in isotopic activities for the first part of Cycle 1B, prior to the power escalation program. The data are from periods of steady-state operation at 1300 MWt for five or more days and represent equilibrium activity.

The I-131 activity, with an eight day half-life, is believed to be the most reliable indicator of fuel leakage. The long half-life should make the I-131 activity relatively insensitive to the size or axial location of the cladding defect. Also, the demineralizer system is effective in cleaning up excess iodine following a power transient, so that I-131 returns to equilibrium quite rapidly. In Cycle 1A, the I-131 activity was well behaved, returning to nearly the same activity each time equilibrium conditions were reached. The trend in Table 4 for I-131 activity is slightly upward, with perhaps a 10% increase in the first eight months of operation.

The Xe-133 activity was quite constant for the first five months, but then it grew to double its former activity from November, 1971 to March, 1972.

The short-lived Kr-88 and Cs-138 activities increased noticeably during the cycle, while other short-lived isotopes increased only slightly. The energy per disintegration for the short-lived Kr-88 and Cs-138 is large and the increase in activity for these two isotopes is equivalent to a 10% increment in total (energy-weighted) activity, expressed as a percent of the Technical Specification activity. Total activity increased from 40% to 60% of the Technical Specification limit, and the balance of the increase is due to the increase in Xe-133 activity.

The interpretation of the data in Table 4 has been that the increase in number of failed rods was very small for the period June, 1971 through February, 1972. The increase in short-lived activity indicates either that existing holes have become larger or there has been a continued buildup of small amounts of uranium on the surface of the rods from erosion of the fuel in the leaking rods. The increase in Xe-133 activity remains unexplained. However, Xe-133 activity is very sensitive to power history, the stripping effect of the volume control tank, and (to a lesser degree) primary system leakage. A similar increase in Xe-133 activity was observed over the last few months of Cycle 1A, and it also was unexplained.

Increase in Activity at 1455 MWt

The power history during the uprating program is shown in Figure 1, with the dates for chemistry samples discussed in detail in this report shown on the diagram..

TABLE 4

CYCLE 1B COOLANT ACTIVITY BEFORE UPRATING

Equilibrium Activity at 1300 MWt with 40 gpm Letdown

Isotope	Half-life	Avg. Energy (MEV)	June 71 6/24/72	Nov. 71 11/10/71	March 72 3/2/72	Ratio (3/72)/(6/71)
I-131	8.04 days	.58	.35	.33	.39	1.11
I-132	2.3 hrs.	2.85	.47	.46	.49	1.04
I-133	21 hrs.	.97	1.37	1.35	1.48	1.08
I-134	53 min.	2.52	1.30	1.36	1.49	1.15
I-135	6.7 hrs.	2.08	.50	.99	.53	1.06
Xe-133	5.27 days	.195	32.40	38.00	71.00	2.19
Kr-85m	4.4 hrs.	.43	1.19	1.10	1.22	1.03
Xe-135	9.2 hrs.	.54	7.10	7.50	7.28	1.03
Kr-87	72 min.	2.42	.85	.85	.86	1.01
Kr-88	2.8 hrs.	2.14	3.05	3.80	3.92	1.29
Cs-138	32.8 min.	3.43	1.53	1.85	2.82	1.84
Rb-88	17.8 min.	2.14	1.66	2.07	2.13	1.29
15 min. $\beta\gamma$			11.1	13.0	14.4	1.30
Total (% of Limit)*			46.6	53.0	65.4	1.40

All activities are μCi/gm of water.
*84/$\bar{E}$ limit in 1520 MWt Technical Specifications

Just before the five day shutdown in early March which preceded the power escalation program, the letdown flow rate was increased from 40 gpm to 70 gpm. The physics testing program called for a rapid increase in power from no load to 1300 MWt for the power coefficient and power defect measurements. Past experience had shown that I-131 activity increased sharply during power transients (by as much as a factor of 30) and the letdown was increased in anticipation of the increased I-131 activity. The difference in purification flow rate must be taken into account when comparing data taken at 70 gpm letdown to data taken at 40 gpm letdown. The increase in activity in escalating power from 1300 MWt to 1455 MWt was larger than expected and the letdown flow rate was maintained at 70 gpm until the refueling shutdown.

Table 5 compares equilibrium activities at 1455 MWt and 1300 MWt. It was anticipated that short-lived activity from either clad surface uranium or the larger cladding perforations would increase linearly with power since the short-lived (recoil) activity should be proportional to the rate of fissioning. Long-lived activity, for which diffusion of fission products through the pellets to the gap should be important, should increase more rapidly than the rate of fissioning because diffusion would be enhanced by the higher fuel temperature. It was believed that dependence on core power would be between P^2 and P^4, with the P^4 dependence applicable to the longest-lived isotopes. Thus the ratio of activities for a power increase from 1300 MWt to 1455 MWt should be 1.12 for the short-lived activity and between 1.25 and 1.55 for the longer-lived isotopes.

TABLE 5

Equilibrium Activity (1455 MWt vs. 1300 MWt)

Activity at 1455 MWt compared to activity at 1300 MWt before escalation.

Isotope	Half-life	1300 MWt[1] 3/2/72	1455 MWt 4/7/72	Ratio 1455/1300
I-131	8.04 days	.23	.39	1.70
I-132	2.3 hrs.	.43	.55	1.28
I-133	21 hrs.	.98	1.38	1.41
I-134	53 min.	1.41	1.42	1.00
I-135	6.7 hrs.	.41	.52	1.27
Xe-133	5.27 days	62.69	105.00	1.67
Kr-85m	4.4 hrs.	1.13	2.04	1.81
Xe-135	9.2 hrs.	6.54	15.10	2.31
Kr-87	72 min.	.82	1.28	1.56
Kr-88	2.8 hrs.	3.61	6.40	1.77
Cs-138	32.2 min.	2.82	1.55	.55
Rb-88	17.8 min.	1.96	3.78	.93
15 min $\beta\gamma$		13.0	22.00	1.69
Total[2] (% of Limit)		62.0	88.50	1.43
Iodine (% of Limit)		18.9	29.7	1.57

(1) Data corrected to higher letdown flow (70 gpm vs. 40 gpm).

(2) 84/$\bar{E}$ limit in 1520 MWt Technical Specifications.

As shown in Table 5, the ratios for the long-lived I-131 and Xe-133 were slightly greater than expected, but the ratios for shorter-lived isotopes (Xe-135, Kr-87, and Kr-88) were much larger than expected with ratios between 1.55 and 2.30. Total energy-weighted activity increased by the ratio 1.43 from 62% to 83% of the Technical Specification limit.

Largely because of the high coolant activity observed after the plant reached 1455 MWt, increased escalation to 1520 MWt was deferred until the activity at 1455 MWt stabilized and an evaluation of the activity increase was made.

Comparison of Activity at 1300 MWt Before and After Power Escalation

It appeared that the activity increase in going from 1300 MWt to 1455 MWt was too large to be caused by power effects alone and that some additional rods must have failed. After operating at 1455 MWt, the plant returned to 1300 MWt for several days following a brief maintenance outage. The activity from this period at 1300 MWt can be compared to the activity at 1300 MWt before the uprating program began to see whether additional fuel failed at 1455 MWt. Table 6 is a comparison of isotopic activities on April 11 (after 3 days at 1300 MWt) and March 2 (after prolonged operation at 1300 MWt, before the uprating). In the April 11 data, the excess activity for longer-lived isotopes had not been completely cleaned up, so only the shorter-lived isotopes can be used in the comparison. The data for the short-lived isotopes are not entirely consistent, but they do indicate an increase in activity of about 20%. The 20% activity increase corresponds to the failure of 15 to 20 more fuel rods.

TABLE 6

Coolant Activity Before and After Operation at 1455 MWt

"Before" data were taken at 1300 MWt and corrected for higher letdown flow rate (70 gpm vs. 40 gpm).

"After" data were taken at 1300 MWt three days after a shutdown transient preceded by 1455 MWt operation.

Isotope	Half-Life	1300 MWt 3/2/72	1300 MWt 4/11/72	Ratio (4/12)/(3/2)
I-131	8.04 days	.23	.47	2.0*
I-132	2.3 hrs.	.47	.47	1.1
I-133	21 hours	.98	1.16	1.2*
I-134	53 min.	1.41	.93	.7
I-135	6.7 hrs.	.41	.41	1.0
Xe-133	5.27 days	62.69	127.00	2.0*
Kr-85m	4.4 hrs.	1.13	1.62	1.4
Xe-135	9.2 hrs.	6.54	11.60	1.8(*)
Kr-87	72 min.	.82	.99	1.2
Kr-88	2.8 hrs.	3.61	4.78	1.3
15 min $\beta.\gamma$		13.0	20.9	1.6(*)

*Isotopes not yet a equilibrium.
(*) Almost at equilibrium.

Activity Following Power Transients

Activity spiking following power transients has been observed at Ginna in both Cycles 1A and 1B. Presumably, activity release from leaking fuel rods is enhanced by the changes in differential pressure across the cladding defect and changes in fuel temperature (and gap size) which accompany changes in power level. The activity spiking effect has not been quantified as a function of power or rate of change in power, but the effect appears to be reproducible This is, if a power transient is repeated several weeks later, the activity spike will be close to the same size as the activity spike for the first transient.

The increase in activity for long-lived isotopes has been large --- I-131 increases by a factor of 10 to 30 and Xe-133 increases by a factor of 2 to 4 for a full power trip followed by a return to power several hours later. The activity increase for shorter-lived isotopes has been much less, approximately 40% to 70%.

The excess I-131 activity following a power transient is effectively removed by the demineralizer system. For a 70 gpm letdown flow rate, the removal half life for I-131 is about 7 hours.

The excess Xe-133 can be removed quite rapidly by periodic "burping" of the volume control tank. The volume control tank is burped by raising the liquid level to displace the gases above the liquid, which are then routed to the gas decay tank. When the level is lowered, evolution of gas from the liquid is increased for a period until equilibrium stripping is again reached with the decay of the isotope in the gas space equal to the removal of the isotope from the liquid. Using a burping frequency of once per shift and a letdown flow

rate of 70 gpm, Xe-133 cleanup with an effective half-life of 10 to 14 hours has been realized. However, the cleanup rate by burping has not been consistently this good. Without burping, the effective cleanup half-life is about four days.

There were two large activity transients during the uprating program, both resulting from a rapid reduction of 1455 MWt to zero load and a return to 1300 MWt within 30 hours. Total activity increased from 78% to 113% of the Technical Specification activity limit for the March 21 outage and from 89% to 130% for the April 7 outage. The Technical Specifications provide that if the coolant activity limits are exceeded following a power transient, a determination must be made within 48 hours that activity is returning to a level below the limits, or corrective action (such as load reduction) must be initiated. This allows sufficient time to observe the cleanup rate to determine whether the activity increase was due to the power change alone or due to a combination of power change and additional fuel failures. In both cases, the activity returned below limits promptly, to 63% and 84% respectively within 48 hours.

Operation at 1520 MWt

On April 21, the reactor was taken from 1300 MWt to 1520 MWt at the rate of 1% per hour following four days operation at 1300 MWt for coolant activity cleanup. The reactor was operated at 1520 MWt for 6 hours, and then returned to 1300 MWt. The purpose of operating briefly at 1520 MWt before the refueling outage was to test the secondary system at the 1520 MWt rating before the annual maintenance period and to test the fuel at 1520 MWt before conducting the fuel inspection.

The coolant activity at 1300 MWt before starting to 1520 MWt was 82% and after reaching 1520 MWt the activity was 90% of the Technical Specification limit. Preparation had been made to burp the volume control tank at 1520 MWt but burping was not required. Apparently the 1% per hour ramp rate was low enough to prevent activity peaking of the longer-lived isotopes.

The six hour operating period at 1520 MWt was too short to determine from coolant activity data whether small numbers of additional fuel rods had failed in going to 1520 MWt.

ATTACHMENT 2
QUESTIONS AND ANSWERS RESULTING FROM A JANUARY 31, 2006 CONFERENCE CALL

NRC Question #4

Provide a description of how Ginna complies with Generic Letter 96-06 at EPU conditions with regard to thermally induced over-pressurization of isolated water filled piping sections in containment including containment penetrations.

Ginna Response

The Ginna specific GL 96-06 evaluation of thermally induced over-pressurization of isolated water filled lines in containment described in RG&E letter to the NRC dated January 30, 1997 and the corresponding NRC SER on GL 96-06 dated October 6, 2003 are unaffected by the EPU due to the following:

- No new potentially water solid piping sections in containment are created by the EPU
- The original Ginna evaluation of over-pressurization potential was conservatively based on a temperature rise to the Ginna design basis containment temperature of 286°F over a ten second period (thermal inertia of the penetration and contained water were conservatively ignored)
- The relief valves installed on containment penetrations as a result of GL 96-06 have a relief capacity of more than two times the required volumetric expansion rate for the most limiting penetration
- The margin in relief valve volumetric capacity and the use of the containment design temperature of 286°F ensure that the existing thermal relief valves are adequately sized to accommodate the change in containment transient temperature due to the EPU operating conditions.

ATTACHMENT 3
QUESTIONS AND ANSWERS RESULTING FROM A FEBRUARY 2, 2006 CONFERENCE CALL

NRC Question #1

Provide replacement pages for section 2.4.1 to address typographical errors in the original licensing report.

Ginna Response

The corrected pages to Licensing Report Section 2.4.1 are as follows:

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

2.4.1.1 Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The Ginna Nuclear Power Plant, LLC (Ginna) staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The Ginna staff's review was also conducted to ensure that failures of the systems do not affect safety functions.

The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10CFR50.55a (a)(1), 10CFR50.55a(h), and:

- GDC-1, insofar as it requires that structures, systems, and components (SCCs) important-to-safety are designed, fabricated, erected, and tested to quality standards commensurate with their importance to functions to be performed.
- GDC-4, insofar as it requires that SSCs be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.
- GDC-13, insofar as it requires that instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC-19, insofar as it requires that a control room is provided from which actions can be taken to operate the nuclear unit safely under normal conditions, and maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCAs).
- GDC-20, insofar as it requires protection systems be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of important-to-safety systems and components.
- GDC-21 insofar as it requires protection systems be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component

or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated.

- GDC-22 insofar as it requires protection systems be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis.
- GDC-23 insofar as it requires protection systems be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.
- GDC-24, insofar as it requires that the protection system is separated from the control systems to the extent that a system satisfying all reliability, redundancy, and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

Specific review criteria are contained in SRP sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Ginna Current Licensing Basis

As noted in Ginna Updated Final Safety Analysis Report (UFSAR), section 3.1, the general design criteria used during the licensing of the Ginna Station predate those provided today in 10CFR50, Appendix A. The adequacy of the Ginna design relative to the general design criteria is discussed in Ginna UFSAR, sections 3.1.1 and 3.1.2. In the late 1970s the Systematic Evaluation Program (SEP) was initiated by the NRC to review the designs of older operating nuclear power plants to reconfirm and document their safety. The results of the SEP review of the Ginna Station were published in NUREG-0821, Integrated Plant Safety Assessment Report (IPSAR), completed in August 1983. The IPSAR describes the methods used by the NRC to assess conformance of the Ginna design to the then current licensing criteria, and identifies cases where bringing the plant into, or closer to, conformance with the newer criteria would provide significant and beneficial additional safety margin. The current UFSAR incorporates the SEP review into the Current Licensing Basis. Specifically, as discussed in section 7.1.2 of the Ginna UFSAR, "Identification of Safety Criteria," the adequacy of Ginna Station instrumentation and control systems' design was reviewed in 1972 on the bases of the General Design Criteria contained in Appendix A to 10CFR50, and the criteria included in IEEE 279-1971, both of which were promulgated after the licensing of the Ginna Station.

Compliance of the design with 1972 General Design Criteria of Appendix A to 10CFR50 is discussed in section 3.1.2 of the Ginna UFSAR. Evaluation of the design with respect to guidance provided in Safety and Regulatory Guides effective in 1972 is discussed in section 1.8 of the UFSAR. The General Design Criteria discussed in section 3.1.2 as they apply to the Reactor Protection, Safety Features Actuation, and NSSS control systems include the following:

- GDC-1 is described in Ginna UFSAR section 3.1.2.1.1, General Design Criteria 1 – Quality Standards and Records. GDC-1 requires that safety-related SCCs are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

All systems and components of the facility were classified according to their importance. Those items vital to safe shutdown and isolation of the reactor or whose failure might cause or increase the severity of a loss-of-coolant accident or result in an uncontrolled release of excessive amounts of radioactivity were designated Class I. Those items important to reactor operation but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity were designated Class II. Those items not related to reactor operation or safety were designated Class III. Note that RG&E no longer uses this classification scheme. The classification of structures and equipment is discussed in Ginna UFSAR section 3.2.

ATTACHMENT 3
QUESTIONS AND ANSWERS RESULTING FROM A FEBRUARY 2, 2006 CONFERENCE CALL

Safety-related SSCs are essential to the protection of the health and safety of the public. Consequently, they were designed, fabricated, inspected and erected, and the materials selected to the applicable provisions of the then recognized codes, good nuclear practice, and to quality standards that reflected their importance. Discussions of applicable codes and standards, quality assurance programs, test provisions, etc., that were used are given in the section describing each system.

A complete set of as-built facility plant and system diagrams are maintained throughout the life of the plant. Records of modifications to the general arrangement and structural plans are also maintained throughout the life of the plant.

- GDC-2 is described in Ginna UFSAR section 3.1.2.1.2, General Design Criteria 2 – Design "Bases for Protection against Natural Phenomena." GDC-2 requires safety-related SSCs shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions.

All systems and components designated Seismic Category I are designed so that there is no loss of function in the event of the safe shutdown earthquake. Measures were also taken in the plant design to protect against high winds, sudden barometric pressure changes, seiches, and other natural phenomena.

On May 22, 1992, Generic Letter (GL) 87-02, Supplement 1, transmitted Supplemental Safety Evaluation Report No. 2 (SSER No. 2) on the Seismic Qualification Utility Group (SQUG) Generic Implementation Procedure, Revision 2, dated February 14, 1992 (GIP-2). Supplemental Safety Evaluation Report No. 2 approved the methodology in the Generic Implementation Procedure for use in verification of equipment seismic adequacy including equipment involved in future modifications and replacement equipment. In letters dated November 30, 1992, and June 8, 1993, the NRC accepted RG&E's response to Generic Letter 87-02, Supplement 1.

- GDC-4 is described in the Ginna UFSAR section 3.1.2.1.4, General Design Criterion 4 – "Environmental and Missile Design Bases." As described in this UFSAR section, Ginna Station received post-construction review as part of the SEP. The results of this review are documented in NUREG-0821, Integrated Plant Safety Assessment Systematic Evaluation Program, R. E. Ginna Nuclear Power Plant.

Environmental Design Of Mechanical And Electrical Equipment (UFSAR section 3.11)

Protection Against The Dynamic Effects Associated With The Postulated Rupture Of Piping (UFSAR section 3.6)

- Pipe Breaks Inside Containment (SEP Topic III-5.A)
- Pipe Breaks Outside Containment (SEP Topic III-5.B)

- GDC-13 is described in Ginna UFSAR section 3.1.2.2.4, General Design Criteria 13 – "Instrumentation and Control." GDC-13 requires that instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.

Instrumentation and controls essential to avoid undue risk to the health and safety of the public are provided to monitor and maintain containment pressure, neutron flux, primary coolant pressure, flow rate, temperature, and control rod positions within prescribed operating ranges.

The fission process is monitored and controlled for all conditions from the source range through the power range. The neutron monitoring system detects core conditions that could potentially threaten the overall integrity of the fuel barrier due to excess power generation and provides a corresponding signal to the Reactor Trip System (RTS). In addition to the ex-core neutron monitoring system, movable in-core instrumentation provides the capability of mapping the core.

The non-nuclear regulating, process, and containment instrumentation measures temperatures, pressure, flow, and levels in the reactor coolant system, steam systems, containment and other auxiliary systems. Process variables

required on a continuous basis for the startup, operation, and shutdown of the plant are indicated, recorded, and controlled from the control room. The quantity and types of process instrumentation provided ensures safe and orderly operation of all systems and processes over the full operating range of the plant.

- GDC-19 is described in Ginna UFSAR section 3.1.2.2.10, General Design Criteria 19 – "Control Room." GDC-19 requires that a control room is provided from which actions can be taken to operate the nuclear unit safely under normal conditions, and maintain it in a safe condition under accident conditions, including LOCAs.

The station is equipped with a control room which contains controls and instrumentation as necessary for operation of the reactor and turbine generator under normal and accident conditions. The control room is capable of continuous occupancy by the operating personnel under all operating and accident conditions, within specified dose limits.

Although the likelihood of conditions which could render the main control room inaccessible even for a short time is extremely small, provisions have been made so that plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the control room. During such a period of control room inaccessibility, the reactor will be tripped and the plant maintained in a safe shutdown condition.

- GDC-20 is described in Ginna UFSAR section 3.1.2.3.1, General Design Criteria 20 – "Protection Systems Functions." GDC-20 requires protection systems be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety

A plant protection system, as described in UFSAR section 7.2, is provided to automatically initiate appropriate action whenever specific plant conditions reach pre-established limits. These limits ensure that specified fuel design limits are not exceeded when anticipated operational occurrences happen. In addition, other protective instrumentation is provided to initiate actions which mitigate the consequences of an accident.

- GDC-21 is described in UFSAR section 3.1.2.3.2, General Design Criteria 21 – "Protection System Reliability and Testability." GDC-21 requires protection systems be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Sufficient redundancy and independence are designed into the RTS to ensure that no single failure results in loss of protection function. The system is designed such that it will accommodate any single component failure and still perform its protective function.

Reliability and independence is obtained by redundancy within each tripping function. In a two-out-of-three circuit, for example, the three channels are equipped with separate primary sensors. Each channel is continuously fed from its own independent electrical sources. Failure to deenergize a channel when required would be a mode of malfunction that would affect only that channel. The trip signal furnished by the two remaining channels would be unimpaired in this event.

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All reactor protection channels are supplied with sufficient redundancy to provide the capability for channel calibration and test at power. Bypass removal of one trip circuit is accomplished by placing that circuit in a half-tripped mode; (i.e., a two-out-of-three circuit becomes a one-out-of-two circuit). Testing does not trip the system unless a trip condition exists in a concurrent channel.

- GDC-22 is described in Ginna UFSAR section 3.1.2.3.3, General Design Criteria 22 – "Protection System Independence." GDC-22 requires protection systems be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

The Ginna Station protection system was designed so that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions do not result in the loss of the protective function. The design includes the techniques of functional diversity or diversity in components design and principles of operation to the extent practical in preventing the loss of the protection functions (e.g., use of turbine-driven and motor-driven auxiliary feedwater pumps).

- GDC-23 is described in Ginna UFSAR section 3.1.2.3.4, General Design Criteria 23 – "Protection System Failure Modes." GDC-23 requires protection systems be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

The RTS is designed to fail-safe upon loss of power. Each reactor trip circuit is designed so that trip occurs when the circuit is deenergized; an open circuit or loss of channel power, therefore, causes the system to go into its trip mode. In a two-out-of-three circuit, the three channels are equipped with separate primary sensors and each channel is energized from independent electrical buses. Failure to deenergize when required is a mode of malfunction that affects only one channel. The trip signal furnished by the two remaining channels is unimpaired in this event.

Reactor trip is implemented by interrupting power to the magnetic latch mechanisms on each drive, allowing the rod clusters to insert by gravity. The protection system is thus inherently safe in the event of a loss of power. Automatic starting of either emergency diesel generator is initiated by redundant undervoltage relays on the 480-V safeguards bus with which the diesel generator is associated, or by the safety injection signal. Engine cranking is accomplished by a stored energy system supplied solely for the associated diesel generator. The undervoltage relay scheme is designed so that loss of 480-V power does not prevent the relay scheme from functioning properly.

- GDC-24 is described in Ginna UFSAR section 3.1.2.3.5, General Design Criteria 24 – "Separation of Protection and Control Systems." GDC-24 requires protection systems be separated from the control systems to the extent that a system satisfying all reliability, redundancy, and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

Evaluation of the Ginna Station RTS isolation was performed as part of the SEP, Topic VII-1.A. The safety evaluation concluded that the RTS is adequately isolated from non safety systems and satisfies the criteria set forth in 10CFR50, Appendix A (GDC 24), and IEEE-279 (1971), section 4.7.2.

- GDC-25 is described in the Ginna UFSAR section 3.1.2.3.6, General Design Criterion 25 – "Protection System Requirements for Reactivity Control Malfunctions." GDC-25 requires protection systems be designed to assure that specified acceptable fuel design limits are not

exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

The RTS is designed to ensure that the specified fuel design limits are not exceeded for any single malfunction of the reactivity control systems. Reactor shutdown with rods is completely independent of the normal control functions. The trip breakers interrupt the power to the rod mechanisms to trip the reactor regardless of existing control signals.

- GDC-29 is described in the Ginna UFSAR section 3.1.2.3.10, General Design Criterion 29 – "Protection Against Anticipated Operational Occurrences." GDC-29 requires protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

The Ginna protection and reactivity control systems are designed to ensure extremely high reliability in regard to their required safety functions in any anticipated operational occurrences. Anticipated failure modes of system components are designed to be safe modes. Equipment used in these systems is designed, constructed, operated, and maintained with a high level of reliability. Loss of power to the protection system will result in a reactor trip.

Other Ginna UFSAR sections that address the design features and functions of the reactor protection and reactor control systems and instrumentation include:

- Ginna UFSAR section 7.1.2, "Identification of Safety Criteria," which describes the reactor protection and reactor control Instrumentation design basis and the requirements for operability and testability.
- Ginna UFSAR section 7.2, "Reactor Trip System (RTS)," describes the design criteria for the reactor protection system and provides a description of reactor protection system operation, reactor trips, permissives, and the interaction of the control and protection systems.
- Ginna UFSAR section 7.3, "Engineered Safety Features Systems (ESFAS)," which describes the design criteria for the ESFAS system and provides a description of the operation, actuation signals, testability, redundancy and independence, and key instrumentation.
- Ginna UFSAR section 7.4, "Systems Required For Safe Shutdown," which identifies the minimum systems required to take the plant from operating conditions to MODE 5.
- Ginna UFSAR section 7.5, "Safety Related Display Instrumentation," identifies the Ginna NSSS and BOP instrumentation subject to the requirements of Regulatory Guide 1.97, Post Accident Monitoring Instrumentation and documents the NRC evaluation and approval of the Rochester Gas and Electric's position relative to the guidance provided in Regulatory Guide 1.97, Revision 3 (reference 1).
- Ginna UFSAR section 7.6, "Other Instrumentation Systems Required For Safety," which describes the instrumentation required for overpressure protection during low power operation, auxiliary feedwater system automatic initiation and flow indication, subcooling meter, DC power system voltage indication and annunciation, and reactor vessel level indication system.
- Ginna UFSAR section 7.7, "Control Systems Not Required For Safety," which provides a description of the reactor control system (rod control, steam dump, pressurizer pressure and level, Steam Generator level control and overfill protection, and turbine bypass), plant response to design loading and unloading, and incore instrumentation. Also included in this section is a description of the nuclear instrumentation system from source range to 120% power, reactor coolant temperature indication, the process computer, and the safety parameter display assessment system (SPDS).

In addition to the evaluations described in the UFSAR, the Ginna Station's electrical and instrumentation and control (I&C) systems were evaluated for plant license renewal. The evaluation of the electrical and I&C components, and the subsequent review and conclusions are discussed in section 2.5 of NUREG-1786, License Renewal Safety Evaluation Report (SER) for the R.E. Ginna Nuclear Power Plant dated May 2004. BOP system

instrument and control systems are not specifically addressed in the SER however some BOP instrumentation, specifically turbine first stage pressure, is described in section 2.3.4.4, "Turbine Generator and Supporting Systems." The programs used to manage the aging effects associated with instrumentation is addressed in the SER, however, transmitters are identified as active and excluded from Aging Management Review.

2.4.1.2 Technical Evaluation

2.4.1.2.1 Introduction

With respect to EPU, the reactor protection system, engineered safety features actuation system (ESFAS), and the reactor control systems, are impacted by the increase in reactor thermal power from 1520 MWt to 1775 MWt and the transition from Westinghouse 14x14 OFA fuel to Westinghouse 14x14 422V+ fuel.

2.4.1.2.2 Input Parameters and Assumptions

The design parameters associated with the uprate and fuel transition are identified in LR section 1.1, "Nuclear Steam Supply System Parameters," Table 1-1. The initial best estimate nominal 1775 MWt full power operating parameters are identified in Table 2.4.1-1 below. The values listed in Table 2.4.1-1 are current best estimates and some values may change as turbine and core design are refined.

Table 2.4.1-1

Parameter	Value
Rated Reactor Core Power MWt	1775
NSSS Power (core Power + RCP Heat) MWt	1781
Main Steam Flow (total flow) lbm/hr	7.7×10^6
Main Steam Flow (per SG) lbm/hr	3.85×10^6
Main Feedwater Flow (plus blowdown total) lbm/hr	7.78×10^6
Main Feedwater Flow (per SG plus blowdown) lbm/hr	3.89×10^6
Main Steam Pressure psig	785
Rated Full Power ΔT °F	67°F
Rated Full Power Average T_{avg} °F	572°F - 574°F
No Load Average T_{avg} °F	547
Pressurizer Level program 0% - 100%	20% - 57%
Full Load Turbine First Stage Pressure psig (subject to final HP turbine design)	645
Feedwater Temperature °F	432

The impact of the physical differences between the Westinghouse 14x14 OFA fuel and the Westinghouse 422V+ fuel has been evaluated in LR section 2.8.1, "Fuel System Design," LR section 2.8.2, "Nuclear Design," and LR section 2.8.3, "Thermal and Hydraulic Design," and LR section 2.8.4.1, "Functional Design of the Control Rod System." As described in LR section 2.8.4.1, the difference in the 422V+ fuel top nozzle design will have an impact on the microprocessor rod position indication (MRPI) system. This change is also described below in LR section 2.4.1.2.3.3, "Control Systems."

2.4.1.2.3 Description of Analyses and Evaluations

The combined effects of the fuel transition and the increase in reactor thermal power have been evaluated for normal operation, operational transients, and accident conditions described in UFSAR sections 6.0, "Engineered Safety Features," 7.7.1.1.4," Reactor Control System Operation," and section 15, "Accidents." These analyses used the most conservative combination of Nuclear Steam Supply System (NSSS) design values from LR section 1.1, "Nuclear Steam Supply System Parameters," Table 1-1. In addition, these analyses included changes to specific emergency safety features actuation system (ESFAS) analytical limits described in LR section 2.4.1.2.3.2 below to provide additional instrumentation calibration margin. The results of the transient and accident analyses are described in the following LR section:

- LR section 2.4.2, "Plant Operability."
- LR section 2.6, "Containment Review Considerations"
- LR section 2.8.5, "Accident and Transient Analyses"

In addition to the ESFAS analytical limit changes requested by Ginna, the analyses identified additional instrumentation and trip setpoint changes that are required to ensure DNB, RCS pressure, and secondary system pressure remain within the allowable design margins and the response to the design basis operational transients remain acceptable. These changes are described in LR section 2.4.1.2.3.1, "Reactor Protection Systems," LR section 2.4.1.2.3.2, "Safety Features Actuation," and LR section 2.4.1.2.3.3, "Control Systems" below.

The above analyses determined that with the exception of the following instruments, the NSSS instrumentation ranges, scalings, and setpoints used in the reactor protection, engineered safety features actuation system (ESFAS), and reactor control instrumentation remained adequate for EPU. The specific changes to these instruments are described in LR section 2.4.1.2.3.1, "Reactor Protection Systems," LR section 2.4.1.2.3.2, "Safety Features Actuation," and LR section 2.4.1.2.3.3, "Control Systems below:

- Power Range and Intermediate Range nuclear instruments
- RCS Temperature instrumentation
- Anticipated Transient Without Scram Mitigation System Actuation Circuitry (AMSAC)
- Main Steam Flow instrumentation

Using best estimate data obtained from EPU heat balances (see Table 2.4.1-1, above), balance of plant (BOP) instrumentation was evaluated to determine required changes using the following methodology:

- System analysis were performed to determine how the EPU process conditions changed compared to the current system operating conditions for the BOP systems.
- For those systems (sub-systems) process conditions changed for EPU, the system instrumentation was evaluated to determine if the instrumentation ranges, scalings, and setpoints remained adequate for EPU conditions.
- For those instruments where the current instrument ranges, scalings, or setpoints are not adequate to support EPU conditions, recommend new ranges, scalings, setpoints, or instrument replacement as required.

Systems covered by this evaluation include the following fluid systems:

- Main Steam
- Extraction Steam
- Condensate and Feedwater
- Station Service Cooling Water

- Component Cooling Water
- Auxiliary Feedwater
- Steam Generator Blowdown
- Feedwater Heater and Moisture Separator Reheater Drains
- Spent Fuel Pool Cooling
- Circulating Water
- Main Turbine Control

With the exception of the following instrumentation, the BOP instrumentation ranges and setpoints were determined to be adequate for EPU. Changes to the following instrumentation is described in LR section 2.4.1.2.3.2, "Safety Features Actuation," and LR section 2.4.1.2.3.3, "Control Systems," below:

- Turbine First Stage Pressure instrumentation
- Main Steam Flow instrumentation
- Main feedwater flow instrumentation
- Main feedwater pump low suction pressure instrumentation
- Setpoint to LP feedwater heater bypass valve
- Heater drain pump flow instrumentation
- Heater drain tank inlet drain temperature instrumentation
- Standby Auxiliary Feedwater flow instrumentation
- Condensate booster pump discharge pressure instrumentation

UFSAR Table 7.5-1, "Comparison of Ginna Station Post Accident Instrumentation To Regulatory Guide 1.97, Revision 3, Criteria," identifies the Ginna NSSS and BOP instrumentation subject to the requirements of Regulatory Guide 1.97, "Post Accident Monitoring Instrumentation." Table 7.5-1 was reviewed for the impact of the identified changes to the NSSS and BOP instrumentation resulting from EPU. Although the setpoints of some of the instruments will be changing, the current calibration range of the instruments except those listed below remain adequate for EPU. The evaluation determined that the only instruments listed in Table 7.5-1 which require changes resulting from EPU are:

- Main Feedwater flow instrumentation
- Main Steam flow instruments
- Standby Auxiliary Feedwater flow instrumentation

Following the implementation of the changes to these instruments described in LR section 2.4.1.2.3.2, "Safety Features Actuation," and LR section 2.4.1.2.3.3, "Control Systems," these instrumentation will continue to satisfy their Regulatory Guide 1.97 requirements.

Technical Specification Limiting Safety System Setting (LSSS) values and trip setpoint values are derived from analytical values used in the above described analyses corrected to account for the specific instrument or control system uncertainty. Ginna calculates instrument uncertainty and setpoints using the methodology in ISA-67-04 as described in Technical Specification Amendment 85 of Improved Technical Specifications and approved by the NRC in the SER dated September 22, 2004 (reference 2).

2.4.1.2.3.1 Reactor Protection

The design bases and description of the Ginna RPS is described in UFSAR section 7.2.1, "Reactor Trip System (RTS)," and includes a listing of the reactor trips, purpose of each trip, and any associated protection and control permissives. The RPS automatically trips the reactor to protect against reactor coolant system damage caused by high system pressure and to protect the reactor core against fuel rod cladding damage caused by a departure from nucleate boiling. The basic reactor tripping philosophy is to define a region of power and coolant temperature and pressure conditions allowed by the primary trip functions (overpower ΔT trip, overtemperature ΔT trip, and nuclear overpower trip). The allowable operating region within these trip settings is provided to prevent any combination of power, temperature, and pressure that would result in a departure from nucleate boiling with all reactor coolant pumps in operation.

Additional trip functions such as a high pressurizer pressure trip, low pressurizer pressure trip, high pressurizer water level trip, loss-of-flow trip, steam-generator low-low water level trip, turbine trip, safety injection trip, nuclear source and intermediate range trips, and manual trip are provided to back up the primary trip functions for specific accident conditions and mechanical failures.

The following is a list of the RPS instrumentation and setpoint changes necessary to ensure the RPS will continue to satisfy it's design functions at EPU conditions.

Nuclear Instrumentation

EPU redefines the 100% power neutron flux levels and will impact the flux level to percent power relationship for the Intermediate Range and Power Range nuclear instruments. Since the source range nuclear instrumentation is deenergized well below the power range, during reactor startup, there are no changes required to the Source Range instrumentation settings. The EPU accident and transient analyses determined that for some accidents the analytical limit for the Power Range high power trip would need to be reduced from the current 118% to 115% which will reduce the Technical Specification LSSS accordingly (112.27% to 109.27%). Although the Power Range high power trip LSSS is decreasing to 109.27%, the current field trip setpoint of 108% has adequate margin to accommodate the new LSSS limit and will not change. The change in the Power Range high power trip LSSS must be approved as part of the Technical Specification change being submitted in the EPU license amendment request.

The accident and transient analyses also determined the analytical limit for the Power Range low power reactor trip at ≤35% of rated thermal power remained adequate for EPU, therefore, the current Power Range low power reactor trip setpoint (24%) remains adequate for EPU. In addition, the Intermediate Range rod stop and reactor trip setpoints (20% and 25% respectively) will remain adequate for EPU.

The Power Range and Intermediate Range instruments are typically recalibrated as a part of the normal core reload process to account for the changes in core design. For EPU, this calibration must also account for the change in percent power level and the 100% power flux level. Once this initial calibration is complete, the Intermediate Range rod stop and trip as well as the Power Range low power reactor trip will function as required. Frequent secondary calorimetrics are used to calibrate the Power Range instruments to calorimetric power during power ascension which maintains the appropriate Power Range flux to percent power relationship. Once calibrated as described above, the power range reactor trips, rod stops and inputs to permissives P-1, P-7, P-8, P-9, and P-10 will function at the appropriate relative power setpoint.

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RCS Temperature Instrumentation

LR section 2.8.5 made recommendations for the T_h, T_c, T_{avg} and ΔT instrument ranges and setpoints to ensure the instrumentation would provide the required indication, core DNB protection, and plant response during accidents and transients over the entire range of operation at EPU conditions. The T_h, T_c, T_{avg}, and ΔT instruments including indications will be recalibrated for a range as follows:

- T_c – 510°F - 590°F
- T_h – 540°F - 650°F
- T_{avg} - 540°F – 620°F
- ΔT – 0°F - ≥80°F (Ginna plans to initially scale the instruments 0°F - 85°F)

In addition, the transient analyses recommended a 4.5 second filter be added in the T_h input to the T_{avg} and ΔT protection channels upstream of the modules which calculate T_{avg} and ΔT. The filters are required to improve the margin to trip for the overtemperature ΔT (OTΔT) and overpower ΔT (OPΔT) trips and also add stability to the rod control system. T_{avg} and ΔT associated alarm setpoints will be recalibrated as necessary to essentially maintain the same margin to alarm at the EPU conditions as existed prior to EPU.

Overtemperature ΔT (OTΔT) Trip

Typically the values for the OTΔT trip setpoints constants are listed in the cycle specific Core Operating Limits Report (COLR) for each fuel cycle. For the initial EPU startup, the OTΔT trip setpoint will be recalibrated with OTΔT constants changed as follows:

Parameter	Current	EPU
Analytical Limit	1.32073	1.30
Constant K1	1.20	1.19
Constant K2	0.0009/psi	.00093/psi
Constant K3	0.0209/°F	0.0185/°F

- Outside EPU Ginna has submitted a request to change from Constant Axial Offset Control (CAOC) to implement Relaxed Axial Offset Control (RAOC) to be implemented during EPU startup. This change was requested by Ginna in reference 3. The current f(ΔI) control function of the OTΔT trip setpoint only responds to a positive axial offset, therefore, an additional module will be added to the system to account for a negative axial offset. The new module will be similar in design to modules originally provided with these circuits. The f(ΔI) function will be calibrated for EPU in accordance with the values listed in the cycle specific COLR.

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Overpower ΔT (OPΔT) Trip

As with OTΔT trip setpoint, the values for the OPΔT trip setpoints constants are typically listed in the cycle specific COLR for each fuel cycle. The accident and transient analyses determined the rate sensitive temperature portion of the setpoint and the f(ΔI) function are not necessary for the OPΔT trip circuit to provide the required protection for maintaining the fuel design limits. For the initial EPU startup, the f(ΔI) function is being disabled and the OPΔT trip setpoint constants changed as follows:

Parameter	Current	EPU
Analytical Limit	1.14877	1.15
Constant K4	1.077	1.077
Constant K5	0.0011/°F	0.0014/°F
Constant K6	0.0262/°F	0
τ_3 time constant	10 seconds	0 seconds

Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) Rod Stops

The setpoint for the P-1 Permissive from two-out-of-four high overtemperature ΔT or overpower ΔT at 1.71°F below trip setpoints is being redefined from a specific temperature value to a value 3% below the full power ΔT. Although stated as an absolute value, the current 1.71°F corresponds to a value 3% below the pre uprate full power ΔT, therefore there is no actual technical change but clarifies the basis for establishing the actual runback setpoint value. At EPU, the 3% below full power ΔT setpoint will correspond to a rod stop and turbine runback occurring at 64.9°F (2.01°F below the trip setpoint)

Anticipated-Transient-Without-Scram Mitigation System Actuation Circuitry (AMSAC)

The Ginna Anticipated-Transient-Without-Scram Mitigation System Actuation Circuitry (AMSAC) as required by 10CFR50.62 is described in UFSAR section 7.2.6, "Anticipated-Transient-Without-Scram Mitigation System Actuation Circuitry." The changes to this circuitry are associated with the arming permissive C-20 which arms and disarms the circuit at a turbine first stage pressure equivalent to 40% nuclear power, and recalibrating the turbine first stage pressure, steam flow, and feedwater flow inputs as well as the 1st stage pressure (Rx power) vs variable time delay circuit for the EPU full load values. The C-20 permissive will be recalibrated to arm/disarm at the appropriate turbine first stage pressure consistent with the new 0% - 100% power nominal turbine first stage pressure range of 0 – 645 psig.

P-7 Permissive Changes

The P-7 permissive is used to bypass the low pressurizer pressure reactor trips during low power or startup operation. It is also used to bypass reactor coolant low flow, undervoltage, and under frequency trips. It is derived from a bistable circuit indicating less than 8.5%power as measured by both first stage turbine pressure (two-out-of-two) and power range (two-out-of-four) less than approximately 8.0%. The power range input is supplied by the P-10 permissive. Calibration of the Power Range input is discussed above in Nuclear Instrumentation. The input from turbine first stage pressure input will be recalibrated to actuate at the value consistent with the new 0% - 100% power nominal turbine first stage pressure range of 0 – 645 psig.

P-8 Permissive Change

The P-8 permissive is used to block a single loop loss of coolant flow reactor trip when 3/4 power range nuclear instruments are less than the permissive setpoint, currently 49% power. The single loop loss of coolant flow trip is unblocked when 2/4 power range nuclear instruments indicate greater than the P-8 setpoint. The analyses performed for EPU determined that an analytical limit of ≤35% power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits. Therefore, the P-8 Technical Specification setpoint limit will be reduced from the current ≤49% power to <29% (analytical limit – instrument uncertainty). This change

must be approved as part of the Technical Specification change being submitted in the EPU license amendment request. The field setpoint for P-8 will be changed from the current 49% nuclear power to 25% nuclear power.

2.4.1.2.3.2 Safety Feature Actuation System

The engineered safety features actuation systems (ESFAS) are used to provide protection against the release of radioactive materials in the event of a loss-of-coolant accident or a secondary line break accident. The engineered safety features systems function to maintain the reactor in a shutdown condition. They also provide sufficient core cooling to limit the extent of fuel and fuel cladding damage and to ensure the integrity of the containment structure. These functions rely on the ESFAS and associated instrumentation and controls. The following identifies the changes to the ESFAS instrumentation, analytical limits, and settings being implemented as part of EPU.

Main Steam Flow Instrumentation

As identified in LR section 2.4.1.2.3 above, the current main steam line flow transmitters require changes to support EPU. The transmitters are currently calibrated with a range of $0 - 3.8x10^6$ which is less than the predicted EPU nominal steam flow of $3.85x10^6$ lbm/hr. The main steam flow transmitters will be recalibrated for a range of $0 - 4.6x10^6$ lbm/hr. This range ensures that the steam flow indication will continue to meet the required Regulatory Guide 1.97 range of 110% of design flow stated in UFSAR Table 7.5-1 plus provide additional scaling to ensure the high-high steam flow signal will occur within indicator range.

Changes to ESFAS Analytical Limits

As indicated previously, in order to increase the calibration margin on ESFAS parameter related setpoints, Ginna requested specific changes to the ESFAS analytical values used in the accident and transient analyses. Since acceptable results were achieved using these values, these values will become the basis for establishing the Technical Specification LSSS values (analytical limit – instrument uncertainty) and field setpoints. In addition, the accident analyses determined that the analytical limit for the high high steam line flow input to the steam line isolation be ≤155% of the nominal EPU full power steam flow (≤5.96E6 lbm/hr). The changes to the ESFAS analytical limits and the effect on the LSSS and field setpoints are shown in the following table. These changes must be approved as part of the Technical Specification change being submitted in the EPU license amendment request.

Parameter	Analytical Limit		Technical Specification LSSS		Field Setpoint	
	Current	EPU	Current	EPU	Current	EPU
Steam Line Isolation High High Steam Flow lbm/hr	≤3.7E6 @755 psig	≤5.96E6 @755 psig	≤3.6E6 @755 psig	≤4.53E6 @785 psig	3.6E6 @755 psig	4.44E6 @785 psig
Steam Line Isolation High Steam Flow lbm/hr @1005 psig	≤0.66E6	≤1.5E6	≤0.42E6	≤1.3E6	0.4E6	0.48E6
Steam Line Isolation Low Tavg °F	≥543	≥530°F	≥544.98	≥544	545	545
Containment Spray Containment Pressure High High Narrow Range - psig	≤32.5	≤33.5	≤31.11	≤32.11	28	28
Containment Spray Containment Pressure High High Wide Range - psig	≤32.5	≤33.5	≤28.6	≤29.6	28	28
Safety Injection Pressurizer Pressure Low - psig	≥1715	≥1700	≥1744.8	≥1729.8	≥1750	≥1750

Feedwater Line Isolation

A new feedwater line isolation valve is being installed in each main feedwater line to minimize the impact to containment integrity during a steamline break inside containment. These new valves will reduce the volume of water potentially available to reach the faulted steam generator for a steamline break in containment. The new

valves will replace crediting the closure the main feedwater pump discharge valve in the accident analyses. Approval of this change is independent of the license amendment required for EPU. License approval for crediting the new isolation valves was requested on April 29, 2005 (reference 4).

Reactor Vessel Level Indication

The reactor vessel level indication is described in UFSAR section 7.3.2.3.1, Reactor Vessel Level Indication System. As described in LR section 2.8.1, "Fuel System Design," the differences in core differential pressure during the transition to the 422V+ fuel is expected to be very small with the RCPs running and should fall within the uncertainty of the reactor vessel level instrumentation and therefore, there is no impact expected to the reactor vessel level indication.

2.4.1.2.3.3 Control Systems

The various reactor control systems are described in UFSAR section 7.7.1, "Control Systems Not Required For Safety." The reactor control systems are designed to limit nuclear plant transients for prescribed design load perturbations, under automatic control, within prescribed limits to preclude the possibility of a reactor trip in the course of these transients. During steady-state operation, the primary function of the reactor control is to maintain a programmed average reactor coolant temperature that rises in proportion to load. The control systems also limit nuclear plant system transients to prescribed limits about this programmed temperature for specified load perturbations. Complete supervision of both the nuclear and turbine generator plants is accomplished from the central control room. This supervision includes the capability to test periodically the operability of the RPS.

The current design basis operational transients described in UFSAR, section 7.7.1 are:

- Step-load change of ±10% or ramp load change of 5% per minute within the load range of 12.8% to 100% of rated power
- Step load decrease of 245 MWe with steam dump
- Turbine trip below 245 MWe with steam dump

Since 245 MWe will no longer represent 50% load at uprate condition, as part of EPU analyses, the reference to a specific MWe is being omitted from the definition of the design basis step-load decrease and the definition revised as a rapid ramp load decrease equivalent to 50% of the EPU rated thermal power (RTP) at a maximum turbine unloading rate of 200% per minute. For the turbine trip load reject, the reactor is assumed to be below the P-9 permissive which defeats the reactor trip due to turbine trip when indicated nuclear power is less than 50%. This change in the design basis load rejection from a step change to a rapid ramp load change at a maximum rate of 200% per minute redefines the load rejection in a more realistic manner and is consistent with uprating projects previously performed on other Westinghouse plants. Following implementation of EPU, the design basis operational transients will be defined as:

- Step-load change of ±10% or ramp load change of 5% per minute within the load range of 12.8% to 100%
- A rapid ramp load decrease equivalent to 50% rated thermal power at a maximum turbine unloading rate of 200% per minute with steam dump
- Turbine trip below 50% reactor power (P-9) with steam dump

The analyses evaluating the response to design basis operational transients at EPU conditions are described in LR section 2.4.2, "Plant Operability." The acceptable response to the design basis operation transients and accidents and transients associated control system failures are based on the changes described for the rod control system and steam dump system being implemented.

Turbine First Stage Pressure Instrumentation

When the turbine generator is on line, turbine first stage pressure increases essentially linear from 0% - 100% turbine load and provides a close correlation of secondary power to reactor power. This allows turbine first stage pressure to be used as a reliable input demand signal or permissive to the various reactor control systems between 0% and 100% reactor power. The pre-EPU 0% - 100% turbine load turbine first stage correlates to 0 – 495 psig. For

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EPU, a new HP turbine rotor is being installed which currently is expected to generate a 0% - 100% power nominal first stage turbine pressure of 0 – 645 psig. Actual full power turbine first stage pressure may change slightly as the HP turbine design is refined and instrument calibrations will be revised accordingly.

The existing turbine first stage pressure transmitters and associated indications will be recalibrated and scaled to a range of 0 – 1000 psig. The inputs to each of the following systems will be recalibrated to respond at the appropriate value for the new 0 – 100% power nominal turbine first stage pressure of 0 - 645 psig.

- AMSAC – arm/disarm circuit permissive C-20 at first stage pressure equivalent to 40% reactor power
- P-2 Permissive – blocks Automatic Rod Withdrawal block at less than 12.8% turbine load
- P-4 Permissive - arms the steam dump system on a sudden drop in turbine load
- P-7 Permissive- in conjunction with P-10, bypasses low pressurizer pressure and low RCS flow, undervoltage, and under frequency trips
- Rod Control power mismatch and non linear gain controls
- Advanced Digital Feedwater Control System (ADFCS)
- T_{ref} input to the Reactor Coolant T_{avg} Control program
- EHC Turbine Control

Rod Control System Changes

The rod control system responds to changes in RCS temperature and secondary load as sensed by the RCS measured T_{avg} instrumentation and turbine first stage pressure instrumentation. The rod control system is designed to maintain average RCS temperature within ±1.5°F of the 0% - 100% T_{avg} program reference value (T_{ref}) derived from 0-100% power turbine first stage pressure (0 – 645 psig). In addition, the rod control system responds to deviations between the reactor power and turbine load as sensed by the mismatch between power range instruments and turbine first stage pressure instrumentation. Both the T_{avg} program and the power mismatch program controls rod speed and direction during normal and transient operation.

The EPU 0 – 100% power T_{avg} temperature program (T_{ref}) is changing from the current 547°F to 561°F to 547°F to approximately 572°F - 574°F based on a 0 – 645 psig turbine first stage pressure. Once the T_{ref} program is calibrated with the turbine first stage pressure range and temperature control band, the rods are expected to respond as designed to average T_{avg} temperature deviations from T_{ref}.

The power mismatch circuits will be calibrated with the new 0 – 100% turbine first stage pressure values which will ensure the power mismatch circuits will continue to provide maximum rod speed with a deviation between nuclear power and turbine power of 10%.

In addition the accident and transient analyses identified changes required to the non linear gain portion of the rod speed control circuits to reduce the speed of the rods to ensure the fuel design limits are not exceeded during response to a single rod drop or rod withdrawal event in addition to providing the stability during the design load change operational transients. The non linear gain inputs are being changed as follows. The range in which only the Low Gain is active is being changed from ±2% to ±1%:

Turbine Load	Low Gain	High Gain
70% -100%	from 1.5°F/% to 0.30°F/%	from 5°F/% to 1.5°F/%
20% - 70%	from 2.25°F/% to 0.45°F/%	from 7.5°F/% to 2.25°F/%
0% - 20%	from 3.0°F/% to 0.6°F/%	from 10°F/% to 3°F/%

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Control Rod Position Indication

The Ginna control rod position indication systems are described in UFSAR section 7.7.1.2.6, "Rod Position Indication System." LR section 2.8.4.1, "Functional Design of the Control Rod Drive System," identified that the difference in the top nozzle length of the Westinghouse 14x14 422V+ fuel will affect the microprocessor rod position indication (MPRI) system. Operation of the MRPI system is described in the Ginna UFSAR section 7.7.1.2.6 and Technical Specification Bases 3.1. The transition point at which the MRPI system indication changes from 0 steps to 12 steps withdrawn occurs when the RCCAs in the bank have been withdrawn 6 steps. The 3 inch height increase in the rod bottom position corresponds to approximately 5 steps, resulting in the transition point occurring at approximately 1 step withdrawn. This could potentially result in the rods not providing a rod bottom indication when inserted. In addition, RCCAs will reach the fully-withdrawn position in 422V+ fuel at 225 steps instead of the current 230 steps. Also, the potential would exist to receive unnecessary rod deviation alarms.

Changes to the rod position indication systems, including possible modifications to the MRPI and/or plant process computer software, or the MRPI hardware itself are currently being assessed to ensure that correct rod position indications are available to the operator.

Pressurizer Level Program

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with measured average T_{avg}. The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off and Letdown isolation occurs while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions.

Analyses described in LR section 2.4.3, "Pressurizer Component Sizing," and LR section 2.8.5, "Accident and Transient Analyses," determined the nominal pressurizer level program for EPU must be changed from the current 35% - 50% program to a new nominal program of 20% at no load conditions to 54.5% - 57% for a full power average T_{avg} of 572°F to 574°F.

Steam Dump Control and Turbine Bypass Systems

The steam dump control and turbine bypass system is comprised of the main steam atmospheric relief valves (ARVs) and the condenser steam dumps. The ARVs can be used to remove sensible heat stored in the RCS at shutdown and cooldown when the condenser steam dumps are not available. The condenser steam dump system removes sensible heat stored in the RCS for a large rapid load decrease or a reactor trip. With condenser steam dump not available, a large rapid turbine load reduction would result in a large steam pressure increase and could potentially challenge the Main Steam Safety Valves (MSSVs). Steam is dumped in order to remove the stored heat in the primary system at a rate fast enough to prevent lifting of the MSSV for a large rapid load decrease, or a reactor trip. The evaluation of the steam bypass system is described in LR section 2.5.5.3, "Turbine Bypass", and LR section 2.4.2, "Plant Operability".

If the condenser is available, the condenser steam dumps (groups A – D) are armed based on a rapid decrease in turbine first stage pressure (equivalent to >10% load decrease) and the dump valves either modulate open or are tripped open based on the magnitude of error (ΔT) between the measured average T_{avg} and the reference temperature(T_{ref}) programmed off turbine first stage pressure.

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As described in LR section 2.4.2, "Plant Operability," the current steam dump valve capacity is sufficient to accommodate a rapid load decrease equivalent to 50% reactor thermal power (RTP) at a rate of 200% per minute or a turbine trip at less than 50% reactor thermal power (RTP) at EPU conditions provided the following changes are implemented in the steam dump control system:

Parameter	Current		EPU	
Turbine Operating Dead band	5°F		4°F	
Proportional Gain in Percent Valve Lift per °F	6.7%/°F		9.1%/°F (Turbine Tripped) 14.3%/°F (Turbine Operating)	
Turbine Operating - ΔT (°F) Required to Modulate Valves Open	Group A Group B Group C Group D	5 – 8.75 8.75 – 12.5 12.5 – 16.2 16.2 – 19.9	Group A Group B Group C Group D	4 – 5.75 5.75 – 7.5 7.5 – 9.25 9.25 – 11.0
Turbine Operating - ΔT(°F) Required to Snap Open Valves	Group A and B Group C and D	12 20	Group A and B Group C and D	7.5 11.0
Turbine Tripped - ΔT (°F) Required to Modulate Valves Open	Group A Group B Group C Group D	0 – 3.75 3.75 – 7.5 7.5 – 11.2 11.2 – 14.9	Group A Group B Group C Group D	0 – 2.75 2.75 – 5.5 5.5 – 8.25 8.25 – 11.0
Turbine Tripped - ΔT(°F) Required to Snap Open Valves	Group A and B Group C and D	8 16	Group A and B Group C and D	5.5 11.0

Condensate and Feedwater System Instrumentation

The changes in the condensate and feedwater system for EPU are driven by the increased flow and associated pressure drops through the system at uprate conditions. As identified above and in LR section 2.5.5.4, "Condensate and Feedwater," the following changes are necessary to condensate and feedwater system instrumentation and setpoints.

- The main feedwater flow transmitters will be replaced and the loop will be re-calibrated from the current 0 – $3.8x10^6$ lbm/hr to 0 – $4.6x10^6$ lbm/hr. The new instrument range will continue to satisfy the Regulatory Guide 1.97 monitored variable of 110% of design flow stated for the main feedwater flow in UFSAR Table 7.5-1.
- Heater drain pump flow measurement loop will be recalibrated and rescaled from the current 0 - $2.684x10^6$ lbm/hr to 0 – $3.0x10^6$ lbm/hr.
- Main feedwater pump suction flow transmitters and control room indicators will be re-calibrated and rescaled from the current 0 – $3.5x10^6$ lbm/hr to 0 – $4.6x10^6$ lbm/hr.
- The condensate pump discharge pressure alarm and standby pump auto start setpoint are being changed to provide sufficient operating margin.
- The condensate booster pump standby pump auto start setpoint is being increased to ensure adequate discharge pressure margin is maintained at EPU.
- The main feedwater pump suction pressure setpoint that provides the pump start permissive and auto open signal to the LP heater bypass valve is being changed to provide the required margin for feedwater pump net positive suction pressure (NPSH) at uprate feedwater flows consistent with the design of the replacement main feedwater pump impellers. In addition, a delay is being added to the LP heater bypass valve open circuit to minimize the potential for spurious actuation and resultant

condensate and feedwater system instability associated with events such as a loss of a condensate pump, condensate booster pump or heater drain pump.

- The main feedwater pump NPSH calculator setpoint which provides an alarm and also opens the LP heater bypass valve on low NPSH is being reset to provide the required margin for feedwater pump NPSH at uprate feedwater flows consistent with the design of the replacement main feedwater pump impellers. As with the main feedwater pump low suction pressure signal, the signal to the LP heater bypass valve will be delayed to minimize the potential for spurious actuation and resultant condensate and feedwater system instability associated with events such as a loss of a condensate pump, condensate booster pump or heater drain pump.

Auxiliary Feedwater System Instrumentation

- The standby auxiliary feedwater pump flow transmitters will be replaced and the flow loop recalibrated for a full scale measurement range of 0 - 300 gpm to accommodate the increased flow required at EPU as described in LR section 2.5.4.5, Auxiliary Feedwater System. The new instrument range for will continue to satisfy the Regulatory Guide 1.97 monitored variable of 110% of design flow stated for the standby auxiliary feedwater flow in UFSAR Table 7.5-1.

Steam Generator Level Control

The steam generator level control system is described in UFSAR section 7.7.1.5, "Steam Generator Level Control." The steam generator water level is controlled by a digital microprocessor controlled steam generator feedwater control system termed the advanced digital feedwater control system (ADFCS). The ADFCS provides automatic control of the programmed level in the steam generators without the need for operator intervention over the range of power operation. This range of operation extends from the point at which the transition is made from feeding via the preferred auxiliary feedwater system to feeding via the main feedwater system on the main feedwater bypass valve (approximately 2-3% power) up to full power. One control system operates on both the Main Feedwater Regulating Valve (MFRV) and main feedwater bypass valves without the need for manual action to switch operating modes or switch between valves. The following is a list of the signals input to the ADFCS. With respect to EPU, of the following inputs to the system, the steam generator levels and valve positions are not impacted, however, for the remaining inputs, the ADFCS program software will need to be updated as necessary with the expected EPU full power values.

- Narrow-range steam generator water level
- Wide-range steam generator water level
- Steam flow
- Feedwater flow
- Feedwater temperature
- Steam generator pressure
- Turbine first stage pressure
- Feedwater header pressure
- Main Feedwater Regulating Valve position

Turbine Generator Control

As part of EPU, a new HP turbine rotor is being installed. As indicated previously, this will result in a new predicted 0 – 100% turbine first stage pressure range of 0 – 645 psig. In addition, with the new turbine, the control valve program will be changed from partial arc emission control (load change controlled by sequential valve opening) to full arc emission control (load change controlled by all valves moving together). The turbine controls will require calibration with the new turbine first stage pressure range to provide the appropriate valve position feedback and appropriate valve demand and position indication. New control valve curves will be required for the change to full arc emission control.

The overspeed protection system for the main turbine includes a mechanical overspeed trip mechanism. This device is an eccentric weight mounted on the turbine shaft rotor extension shaft. It is designed to trip the main turbine unit to ensure the turbine speed remains less than the 120% of design speed (2160 rpm). There is also an Overspeed Protection Controller incorporated into the Electro Hydraulic Control (EHC) system. This includes a load drop anticipator and an auxiliary governor function. The load drop anticipator logic will rapidly close all control and intercept valves on a complete loss of load, and rapidly close the intercept valves on a partial loss of load. If the auxiliary governor senses an overspeed condition at 103%, the system will close the reheat intercept valves and modulate close the control valves until the overspeed condition clears.

Presently the turbine mechanical overspeed trip allowable setpoint is less than 110% of rated speed (1980 rpm). An evaluation of the increased mass flow and other EPU hydraulic conditions indicate the allowable overspeed setpoint needs is to be reduced to less than 109.3% rated speed (1969 rpm). Results from overspeed tests performed between 1997 through 2005 indicate the current average overspeed setting to be 108.81% ±0.2%. Since the current setting is less than the new allowable setpoint, the current mechanical overspeed setting is acceptable for EPU.

The load drop anticipator circuit will need to be recalibrated with the EPU 0% - 100% full load megawatts and the reheat crossover pressure to the LP turbines. The 0% - 100% reheat pressure will be recalibrated from the current 0 – 125 psig to 0 – 200 psig.

Plant Computer

The plant process computer system (PPCS) is described in UFSAR section 7.7.6, "Plant Process Computer System and Safety Parameter Display Assessment System." Although EPU will impact the range of many process parameters monitored by the PPCS, the functions performed by the plant computer will not change as a result of EPU. The PPCS inputs associated with the instrumentation changes mentioned above will be rescaled consistent with the range of the PPCS input changes using the station plant change process.

Computer changes associated with the core reload for EPU will be performed in accordance with the cycle specific core reload process.

In-core Instrumentation

The in-core thermal thermocouples (T/Cs) and in-core movable detectors are described in UFSAR section 7.7.4, "In-Core Instrumentation." With respect to EPU, the in-core T/Cs will be exposed to higher core exit temperatures, however, these temperatures are well within the design values for these instruments and will not impact the ability of the in-core thermocouples to perform their design function. With respect to the in-core movable detectors the full power EPU flux levels will be higher; however, it is still within the design capability of the detectors. Therefore, the in-core thermocouples and movable detectors will continue to provide indication as designed.

2.4.1.2.3.4 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

Safety related instrumentation or instrumentation that performs a function necessary to accomplish one of the five regulated events are scoped within license renewal, however instruments typically are scoped as active components and are excluded from aging management review. Cables, connectors, pipes and tubes that service the in-scope instruments are passive and require aging management review. The changes to instrumentation for power uprate are predominately rescaling and recalibration of existing instrumentation and introduce no new components or configuration of the instruments. The rescaling and recalibration of these instruments do not impact the design function of the instruments and do not effect the conclusions stated in the licensing renewal evaluations.

For the limited number of cases discussed above, instruments or active instrument components must be changed to ensure the operability of the instruments for EPU conditions. These instrument changes are being performed in accordance with the plant modification process which evaluates the impact of the change with regard to license renewal and aging management.

2.4.1.3 Results

The changes to the instrumentation and controls for EPU are the result of accident and transient analyses and system evaluations to verify the systems and controls will continue to provide the required indication, protection actions, and plant response as originally designed. The changes ensure the DNB values remain within acceptable limits and

the RCS pressure boundary and the main steam pressure boundary are maintained within the design values. There are no new protection or control systems required to support EPU. The identified instrumentation recalibration and instrument rescaling will ensure the instrumentation continues to allow monitoring plant process parameters during normal, transient and accident conditions and provide protective functions as required.

2.4.1.4 References

1. Letter from A. R. Johnson (NRC) to R. C. Mecredy (RG&E), Subject: Emergency Response Capability - Conformance to Regulatory Guide 1.97, Revision 3, dated February 24, 1993.
2. Letter from Robert L. Clark (NRC) to Mary G. Korsnick (Ginna), Subject: R. E. Ginna Nuclear Power Plant - Amendment Re: Revision to Core Safety Limits and Safety System Instrumentation Setpoints (TAC No. MB4789), dated September 22, 2004.
3. Letter from Mary G. Korsnick (Ginna) to Donna M. Skay (NRC), Subject: License Amendment Request Regarding Adoption of Relaxed Axial Offset Control (RAOC), dated April 29, 2005.
4. Letter from Mary G. Korsnick (Ginna) to Donna M. Skay (NRC), Subject: License Amendment Request Regarding Main Feedwater Isolation Valves, dated April 29, 2005.

2.4.1.5 Conclusions

The Ginna staff has reviewed the instrumentation and control systems relevant to the effects of the proposed EPU on the functional design of the reactor protection, safety features actuation, and control systems. The Ginna staff concludes that the evaluation has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis, including the revised load rejection design basis to a rapid ramp load reduction equivalent to 50% rated thermal power at a maximum unloading rate of 200% per minute. The Ginna staff further concludes that the systems will continue to meet the Ginna current licensing basis with respect to the requirements of 10CFR50.55a(a)(1) and 10CFR50.55(a)(h) and GDC-1, GDC-2, GDC-4, GDC-13, GDC-19, GDC-20, GDC-21, GDC-22, GDC-23, GDC-24, GDC-25, and GDC-29. Therefore, the Ginna staff finds the proposed EPU acceptable with respect to instrumentation and controls.

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NRC Question #2

Clarify the acceptance criteria provided on Licensing Report page 2.2.2.3-3.

Ginna Response

The corrected acceptance criteria for Licensing Report page 2.2.2.3-3 are provided below.

Acceptance Criteria

Revised maximum stress intensity ranges and cumulative fatigue usage factors were calculated and compared to the following acceptance criteria:

- The maximum range of primary-plus-secondary stress intensity resulting from mechanical and thermal loads shall not exceed 3Sm at operating temperature. In lieu of satisfying 3Sm, the design of the components below the vessel flange shall be considered acceptable if the criteria specified for a plastic analysis per paragraph N-417.6(a)(2) of the ASME B&PV Code, Section III, Division 1, 1965 Edition can be met, and the design of the components of the replacement closure head and main closure region shall be considered acceptable if the criteria specified for a simplified elastic-plastic analysis per Section NB-3228.5 of the ASME B&PV Code, Section III, Division 1, 1995 Edition through 1996 Addenda can be met.

- The maximum cumulative usage factor resulting from the peak stress intensities due to the normal and upset condition design transient mechanical and thermal loads cannot exceed 1.0 in accordance with the procedure outlined in Paragraph N-415.2 of the ASME B&PV Code, Section III, Division 1, 1965 Edition (Reference 18) for the vessel components below the vessel flange and, in Paragraph NB-3222.4 of the ASME B&PV Code, Section III, Division 1, 1995 Edition through 1996 Addenda (Reference 19) for the components of the replacement closure head and main closure region.

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QUESTIONS AND ANSWERS RESULTING FROM A FOLLOW UP ON THE FEBRUARY 2, 2006 CONFERENCE CALL

NRC Question #1

With respect to human factors Section 2.10 of the Licensing Report, this response is provided as supplementary information to the RAIs in NRC letter dated October 25, 2005 (initial response provided in Constellation letter dated December 6, 2005):

Ginna Response

<u>**OPERATOR TRAINING/OPERATOR ACTIONS/ PROCEDURES**</u>

<u>Changes in Emergency and Abnormal Operating Procedures</u>

1. In part (a) of item 1 of Section 2.11.1.1 of the licensing report, a Westinghouse Owners Group initiative is referenced as being part of the effort to streamline the E-0 automatic action verification steps in order to meet assumed operator action timelines for specific accident scenarios. What is this initiative and how does streamlining the E-0 automatic action verification steps affect the assumed operator action timelines for this proposed EPU request? Are there any differences in the "streamlined" E-0 automatic action verification steps as referred to in the Westinghouse Owners Group initiative and this proposed EPU request? If different, what are their differences and their effects?

   Response

   A Westinghouse Owners Group (WOG) Emergency Response Guideline (ERG) Direct Work (DW) request, DW-96-038, was submitted to resolve an issue related to high pressure plant response time for terminating Safety Injection (SI) flow on spurious SI. As a result of changes in Control Room protocol and communications in recent years, the time required to complete E-0 and transition to the appropriate recovery guideline has increased impacting the operators' ability to implement the required actions in a timely manner. The resolution of this DW addressed issues identified in WCAP-14996, ERG Operator Response Time Assessment Program Final Report. Since timeliness issues could affect other events such as S/G tube Rupture, the DW resolution was expanded to include Low Pressure plants. The DW provides guidance supporting relocation of several E-0 automatic action verification steps to an attachment which can be performed as time permits allowing a more expeditious progression through the procedure and transition to the appropriate optimal recovery guideline. This will enhance the Operators ability to accomplish time critical actions within the required timeframes.

   The WOG guidance for resolution of the DW request allowed the flexibility to relocate any or all of E-0 steps 5-18 (verification of auto actions) to an attachment to be performed independently by a licensed operator while the remainder of the E-0 action steps is directed by the SRO procedure reader. The Ginna approach will be to relocate many, but not all, of the WOG identified steps to an attachment. Therefore, the Ginna change will be consistent with the WOG recommendation.

2. In part (b), what will be the new time to initiate the functional restoration procedure for the standby auxiliary feedwater system and how will this impact the operator's other actions during the high energy line break scenario?

   Response

   The time to S/G dry-out for a feed line break without initiation of feed to the affected S/G will be reduced from the current 50 minutes to 35 minutes at uprate conditions. From License Report section 2.5.4.5, Table 1, Standby Auxiliary Feed (SAFW) flow of at least 235 gpm must be established within 14.5 minutes. Loss of heat sink is a red path critical safety function and should be addressed after completion of the immediate action steps of E-0, Reactor Trip or Safety

Injection. Currently in the heat sink procedure, FR-H.1, the operators are directed to attempt to restore main feed water flow prior to initiating SAFW flow, since, commercially, condensate grade water is preferable to service water for feed to the S/Gs. Actions required for initiating main feed flow are time consuming and installation of the new feed isolation valves will result in increasing the time required to establish feed flow. The proposed change will direct initiation of SAFW to the S/Gs as the first option after normal AFW has been attempted. The SAFW system was installed for the specific purpose of mitigation of a high energy line break which renders normal AFW inoperable.

3. In part (c), what are the "certain" events and the "appropriate" procedures affected by the increase in the Standby Auxiliary Feed flow requirements? Do the flow requirements for normal AFW also increase? If so, which events and procedures are affected for normal AFW?

Response

The high energy line break (HELB) in the intermediate building which results in unavailability of the normal AFW pumps and delayed initiation of S/G feed using a Standby AFW pump will require the increased flow. Procedure FR-H.1, Response to Loss of Secondary Heat Sink, will be modified to incorporate this requirement. Additionally, as a result of the increased core decay heat, Appendix R events resulting in the unavailability of the RHR system for cooldown from Mode 4 to Mode 5 using water solid S/G cooldown will require increased SAFW flows to ensure RCS cooldown can be accomplished within 72 hours. Procedures ER-FIRE.1, -.2 and -.3, for fires in the Control Room, cable tunnel and Auxiliary Building basement/mezzanine will be modified to address this requirement. The flow requirements for the normal AFW pumps are not increased. The only procedural change required for normal AFW is in FR-H.1 for delayed restoration of S/G feed. The normal AFW step in FR-H.1 will require start of two MDAFW pumps or the TDAFW pump to meet the delayed feed requirements. If this cannot be accomplished, then SAFW is initiated.

4. In part (d), if the main feedwater isolation valves are inoperable, how much time will the operator have to isolate the main feedwater manually? Confirm the amount of time required to complete the MFW isolation step decreases.

Response

The new main feed isolation valves are designed to fail safe on loss of air or DC power and the Technical Specification revision to incorporate the new valves does not allow extended operation with inoperable valves. If one or both of the valves were to stick open when required to close during an accident scenario, the main feed regulating and bypass valves will still receive that feed isolation signal and the main feed pumps will trip and their discharge valves will close. There will be no additional manual operator actions required to accomplish feed isolation.

During the process of simulator EOP validation and operator training, critical operator action times will be verified as required by current commitments. The intent is to ensure that these action times can be met for uprate conditions and not necessarily to determine if the response times are different than previous response times. The intent of the initial response in part (d) was that since the requirement for the manual operator action (to close the main feed regulating and bypass valves from the Control Board) in the main feedwater isolation step was eliminated, the time required for the operator to accomplish the step would decrease. In the event that a MFIV becomes inoperable while the plant is at power, the requested Technical Specification change would require closure or isolation of the affected MFIV within 72 hours and subsequently verified closed or isolated once per 7 days until restored to operable.

ATTACHMENT 4
QUESTIONS AND ANSWERS RESULTING FROM A FOLLOW UP ON THE FEBRUARY 2, 2006 CONFERENCE CALL

5. In part (g), what will be the contingency action to cool down the pressurizer when the residual heat removal is not available? Will this be an operator manual action?

   Response

   A fire which renders both trains of the RHR system inoperable will require use of water solid S/G cooldown to transition from mode 4 to mode 5. If the fire also results in shorting both pressurizer PORV block valves such that they fail closed without torque switch protection it may result in inability to open the valves manually. In this case the pressurizer PORVs will not be available to cool down the pressurizer and, for uprate, pressurizer cooldown from ambient losses may not be adequate to ensure attaining cold shutdown within the 72 hour timeframe. Engineering is currently re-evaluating the weak link assessment of the PORV block valves. If the conclusion is that the PORVs may not be available, the contingency action will be to utilize pressurizer auxiliary spray to accomplish cooldown within the required time.

6. In parts (b, d, and e), enhancements are being made to existing systems to reduce operator action times in the accident scenarios provided in those sections. What will be the operator response times as a result of these enhancements and how have these reduced operator action times been demonstrated to be both feasible and reliable (reproducible by more than one operator/crew)? Specifically, in (e), how much will the time available for restoration of charging flow be reduced? Also, are there any compensatory measures taken as a result of the reduced time available?

   Response

   The Appendix R mitigation procedures are currently being evaluated and revised to enhance procedural direction and to incorporate the physical plant modifications. A comparison of the proposed procedure revisions to the existing timelines for accomplishing the Appendix R strategies indicates that critical operator action times will continue to be met, however, when the procedure changes are finalized, formal walkdowns will be performed to validate acceptable response times, using multiple crews. This validation will be completed and any issues resolved prior to operation at uprated plant power levels.

   The available time to restore charging will be reduced from 36 minutes to 24 minutes. The compensatory actions taken to reduce the time necessary include a review and re-prioritization of operator actions coupled with installation of two plant modifications. The plant modifications include relocation of the 'A' charging pump control power transfer switch and installation of a backup air supply providing charging pump speed control. These modifications are being implemented only for the purpose of reducing the time necessary for operators to restore charging and achieve the required flow.

7. In part (h), how will the minor modifications for Appendix R local operating stations benefit operator response times overall? Will the modifications reduce the time available to the operators to take the required responses or reduce the time necessary for the operators to affect the required responses? Also, are the modifications listed in this section the only changes being considered for the local operating stations?

   Response

   As discussed above, the time available for restoration of charging in Appendix R events will decrease after EPU. However, each of the three modifications identified will reduce the time necessary for the individual operators to complete actions crucial for event mitigation. The backup air supply to the charging pump speed control will allow increase in charging pump speed as soon as the pump is started. Currently, speed control is procedurally dependant on start and

alignment of the diesel air compressor, a task that could require 10-15 minutes to accomplish (the task is performed locally by an operator after several other procedure supporting tasks). The immediate ability to increase charging pump flow after pump start without requiring manual operator action to restore air also results in a beneficial impact on fire risk. The relocation of the 'A' charging pump DC control power transfer switch eliminates the need for the operator to travel two floors down to the auxiliary building basement (to place charging pump in local control) and two floors up to bus 14 (to transfer DC control power) and then two floors back to the basement to start the charging pump. This activity would probably be performed while wearing a Scott air pack. This modification should result in a 2-3 minute reduction in the time necessary to restore charging.

The modification to provide local control of the TDAFW pump discharge valve, MOV-3996, coupled with recommended procedure changes, will significantly enhance the ability to restore and control feed flow to the S/Gs. The valve controls will also be located on the panel with the Appendix R dedicated S/G level and TDAFW flow indications resulting in more efficient control of heat sink.

There is one additional modification that was not discussed. Currently, only the 'A' S/G has dedicated Appendix R level indication at the local panel. In order to meet the requirement for capability to cooldown on both S/Gs for certain Appendix R scenarios, a fire hardened 'B' S/G level channel will be added to the local Appendix R panel. The sole purpose of the modifications to control of the TDAFW discharge valve and 'B' S/G level indication is to reduce the time necessary for the operators to affect the required responses. These timelines will be verified using operating shifts prior to increasing plant power to the uprated power level.

Changes to Operator Actions Sensitive to Power Uprate

8. The Licensee states in this section, "operator actions listed include the following:" Is the listing all inclusive or are there other actions?

   The list provided in the response was intended to provide some of the more significant examples and was not intended to be an all inclusive list. The operator training plan for the uprate will provide a comprehensive review of plant changes. Practical exercises on the plant simulator will be designed to provide the operators with a solid understanding of plant response and system interactions for the uprate plant.

9. In part (a) of item 2, what will be the reduced time for the concurrent initiation of hot and cold-leg recirculation and how does this affect the operator actions for a large break loss-of-coolant accident (LOCA)? Is the reduced allowed time still sufficient for the operators to accomplish the appropriate actions?

   Response

   The time allowed for initiation of concurrent cold leg and upper plenum injection for all LOCA break sizes for mitigation of boron precipitation is being reviewed as part of our response to the October 28, 1005 RAIs. For large break LOCAs, RCS depressurization results very quickly. Providing concurrent hot and cold leg injection within a few hours is readily achievable.

   For LB LOCA, the allowed time for simultaneous injection is reduced to 5.5 hours after switchover. This is not a concern as there are few required operator actions after switchover and before initiating simultaneous injection in a LB scenario. For SB LOCA, the allowed time for simultaneous injection is 6.5 hours after the break occurs. The EOP actions for initiating RCS cooldown and depressurization for smaller breaks are located early in ES-1.2, Post LOCA Cooldown and Depressurization. Timed simulator scenarios for operator response to RCS LOCA

indicate that transition to ES-1.2 will occur at about 28-30 minutes (without the E-0 enhancements discussed previously). Cooldown and depressurization will be initiated within 1 hour. With an RCS cooldown rate of 80-100°F/hr (EOPs direct a maximum cooldown rate approaching but not greater than 100°F/hr) Westinghouse analysis has demonstrated that temperature and pressure can be reduced to the point of RHR injection within 6 hours. When RHR injection occurs, simultaneous injection will also occur since RHR will be injected into the upper plenum while SI pumps will be injecting into the cold leg. This analysis demonstrates that sufficient time exists to establish simultaneous injection for SB LOCA scenarios. This time line will be validated using operating crews on the simulator. Operator training emphasizes that cooldown rate should be established as close to 100°F/hr as possible. The EOPs are being reviewed and revised as necessary to ensure that RCS injection (hot/cold) is swapped when required by the revised boron precipitation guidance.

10. Will the second spool piece installation require additional time? If so, what will be the effect of the additional time?

Installation of the spoolpieces is required in preparation for S/G water solid cooldown with RHR unavailable. S/G solid water cooldown is assumed to commence at about 50 hours after event initiation. This provides adequate time for additional maintenance personnel to arrive at the plant and install both spoolpieces. Spoolpiece installation can be done in parallel, therefore, the time necessary to install should not be affected and spoolpiece installation should be accomplished well before solid water cooldown is assumed to begin.

11. In part (e), what is the change regarding the initiation of the standby auxiliary feedwater to reflect the reduced time of steam generator dry out due to EPU? Please describe what operator actions will be affected as a result of the change and how they will be affected. What is the time to S/G dryout under the current accident scenario?

Response

As discussed in the answer to question 2 above, FR-H.1 will be revised to direct initiation of SAFW immediately after determination that normal AFW is not available. Loss of heat sink is a red path critical safety function and should be addressed after completion of the immediate action steps of E-0, Reactor Trip or Safety Injection. Currently in the heat sink procedure, FR-H.1, the operators are directed to attempt to restore main feed water flow prior to initiating SAFW flow, since, commercially, condensate grade water is preferable to service water for feed to the S/Gs. Actions required for initiating main feed flow are time consuming and installation of the new feed isolation valves will result in increasing the time required to establish feed flow. The proposed change will direct initiation of SAFW to the S/Gs as the first option after normal AFW has been attempted. The SAFW system was installed for the specific purpose of mitigation of a high energy line break which renders normal AFW inoperable.

The time to reach S/G dryout with no feedwater addition during an Appendix R scenario decreases from the current 50 minutes to 35 minutes for EPU. The existing Appendix R operator timelines show that feed is restored to the S/G within 20 minutes. Additionally, the Appendix R fire procedures are being revised to increase the efficiency of implementation by eliminating several local valve manipulations required to establish feed. These changes will ensure that restoration of S/G feed can be accomplished well before S/G dryout.

ATTACHMENT 4
QUESTIONS AND ANSWERS RESULTING FROM A FOLLOW UP ON THE FEBRUARY 2, 2006 CONFERENCE CALL

Changes to Control Room Controls, Displays and Alarms

12. In part (e) of item 3, what type of digital technology will be used to acquire the data? How will this new technology affect the operators in the control room?

    Response

    The reference to new digital data was meant to encompass additional input to the plant process computer related to some of the uprate modifications. An example would be pressure indication and alarms for the air system on the new main feed isolation valves. New inputs to the computer will be informational only.

Changes to the Operator Training Program and the Control Room Simulator

13. Although it is stated that there are training cycles planned to address the EPU modifications, is there a timeline established for the operator training as well as the control room simulator modifications in accordance of implementing the EPU in 2006? If not, when will one be developed?

    Response

    A high level training and simulator modification schedule has been developed and a detailed, resource loaded schedule has been generated. Operator overview training for the Uprate is currently in progress, including general discussions of major plant changes, a session on Relaxed Axial Offset Control (RAOC) and familiarization with the new mono-block turbine and control valve modifications. The 2006 training plan includes review of NSSS and BOP I&C systems, license amendment requests and secondary systems review through June, 2006. The 2 training cycles preceding the refueling outage (July - September) will be primarily dedicated to the Uprate changes (both simulator and classroom). During the refueling outage, there will be just in time training for plant startup and the Uprate testing plan.

14. How has the simulator been verified and validated to make certain that changes to systems operations resulting from the EPU have been accurately modeled by the plant simulator?

    Response

    The uprate plant modifications to the simulator are being done using the normal configuration control process. The simulator uprate will be completed prior to the scheduled operator uprate training cycles. Testing will be based on predicted performance data developed in alternative analyses. Uprate acceptance tests will be run on the simulator and the test results will be reviewed for acceptability. For the ten transients required by ANI/ANS-3.5, RETRAN predictions will be used as the benchmark for simulator performance. Once actual data from plant startup and testing is available, the simulator performance will reviewed and adjusted as needed to agree with actual plant performance.

15. The Licensee states that "Many of the procedural changes especially to the Emergency/Abnormal Procedures and other off-normal procedures will be reviewed and validated by Operations personnel." By implementing the EPU, should this require all current procedures to be reviewed and validated?

Response

The procedures requiring change for uprate have been identified. The majority of the procedures will require only minor revision (setpoints, notes, cautions and minor guidance enhancements). Approximately 15-20 operations procedures (~10%) require changes that may significantly alter task sequence or method of task performance. These changes will require simulator validation. Many of the plant changes will not directly affect the response of the simulator (such as the Appendix R procedure local control station guidance changes). Changes such as these will be validated by simulated walk through in the field. All procedure changes will be reviewed by Subject Matter Experts (SMEs) from operations in accordance with the normal procedure change process. The Operations Department and the Emergency Procedures Committee will determine which procedures require simulator or plant walk through validation.

General Questions

16. Will all of the changes to the emergency procedures, operator actions, control room displays and alarms, Safety Parameter Display System, operator training and simulator be in place prior to the implementation of the EPU? If not, what changes will not be in place and what is the time frame for putting the remaining changes into effect? What effect will delaying any changes to after implementing the EPU have on assuring that operator performance actions sensitive to the power uprate will be successfully performed when required?

Response

All changes to the Emergency Procedures, operator actions, control room displays and alarms, Safety Parameter Display System, operator training and simulator will be in place prior to operation at the uprate power level.

ATTACHMENT 5
QUESTIONS AND ANSWERS RESULTING FROM A FEBRUARY 6, 2006 CONFERENCE CALL

NRC Question 1
Provide clarification as to why the operator dose during transit to isolate the B train Spent Fuel Pool Heat Exchanger is estimated at 0.6 rem, whereas the operator dose during transit to Safeguards Bus 14 and 16 are estimated to be negligible.

Ginna Response
As indicated in Table 2.10.1-1 of the EPU Licensing Report, access to isolate the B train spent fuel pool heat exchanger (SPF HX) is postulated at T=10 mins after the LOCA, whereas access to Safeguards Bus 14 and 16 are postulated at T=1 day after the LOCA.

As shown in the access route sketches included in the response to NRC Question 5, the B train spent fuel pool heat exchanger (SPF HX) isolation valves are located on the operating floor of the Auxiliary Building. Engineering analyses supporting the EPU licensing report indicate that the only radiation source at T=10 mins post-LOCA is the airborne radioactive material inside containment, that the T=10 min operator dose during transit via this access path is 0.6 rem, and that approximately 60% of this dose is received during passage inside the auxiliary building. The analyses also show that due to radioactive decay, the operator dose during transit due to containment shine at T=1 day and T=10 days, for this same access path, would be less than 0.6 rem by a factor of 200 and 2E5, respectively.

As shown in the access route sketches included in the response to NRC Question 5, Bus 14 is also located on the operating floor of the Auxiliary Building, close to the valves used to isolate the B SPF HX. Access to Bus 14 (Area I) is postulated at T=1 day. As documented in the original 1979 Design Review Report, which was approved by NRC via the Safety Evaluation Report dated May 23, 1984, the radiation level in this area is primarily due to containment shine. Therefore the operator exposure in this area due to airborne radioactive material inside containment at T=1 day will be approximately 0.6/200 = 0.003 rem which is less than 1% of the occupancy dose limit of 5 rem. Consequently, operator dose during transit to Bus 14 has been reported as negligible.

As shown in the access route sketches included in the response to NRC Question 5, Bus 16 is located in the Intermediate floor of the Auxiliary Building, below Bus 14. Access to Bus 16 (Area H) is postulated at T=1 day. Per the Vital Area Radiation Dose Summary Table 4-3 of the 1979 Design Review Report, the operator dose while accessing this target area at T = 1 hr is negligible. The text of the report indicates that the pre-EPU dose rate in this area, at T=1 day and T=10 days, is 2.4 R/hr and 0.4 R/hr, respectively, and that these dose rates are primarily due to the safety injection / recirculation components located on the floor below, i.e., in the Auxiliary Building Basement. Using the T=1 day EPU scaling factor (i.e., 1.38), the EPU dose rate in this area can be conservatively estimated to be 3.3 R/hr. The traversing distance from the entrance to the east stairway at the operating floor to Bus 16 located on the Intermediate floor is less than 70 ft. Assuming a walking speed similar to that used in the original Design Review report of 200 ft /minute, the round trip from the stairway entrance to Bus 16 would take (70 X 2) ft / 200 ft/min = 0.7 mins. As a result, operator exposure during transit, due to the piping located below the floor, is estimated to be approximately (0.7/60) hr X 3.3 R/hr = 0.039 rem. Including the contribution due to containment shine (increased from the 0.003 rem estimate to 0.006 rem to address additional traversed distance within the Auxiliary Building operating floor) would result in an operator exposure of approximately 0.039 + 0.006 ≈ 0.045 rem, which is less than 1% of the occupancy dose limit of 5 rem. Consequently, operator dose during transit to Bus 16 has been reported as negligible.

NRC Question 2
Provide clarification as to why the operator dose during transit to and from the Radwaste Control Panel is estimated to be negligible.

Ginna Response
As indicated in Table 2.10.1-1 of the EPU Licensing Report, access to the Radwaste Control Panel is postulated at T=10 days after the LOCA. The occupancy time is listed as 2 minutes and the occupancy dose is listed as 2.7 Rem. As shown in the access route sketches included in the response to NRC Question 5, the Radwaste Control Panel is located in the Auxiliary Building Basement with the access route

beginning from the Operating Level of the Auxiliary Building two floors above and continuing down the stairwell through the Intermediate Level to the Basement where the stairwell exits less than 15 feet from the Radwaste Control Panel. The time the operator is in the lower level stairwell and transiting to and from the panel on the Basement Level is estimated to be less than 30 seconds. This 30-sec transit time on the Basement Level is encompassed by the 2 minute occupancy time since operator actions at the panel are expected to take less than 1 minute and 30 seconds. Given that the operator actions are taken at least 10 days after the LOCA, detailed planning will be conducted and dose mitigation efforts such as temporary shielding would be used as necessary.

The remaining transit time to the Radwaste Control Panel is spent on the Operating and Intermediate Levels of the Auxiliary Building. At 10 days after the LOCA, dose rates on the Operating and Intermediate Levels of the Auxiliary Building are very low (see response to NRC Question 1) as compared to those on the Basement Level. The dose incurred while transiting these areas is negligible compared to the occupancy dose limit of 5 rem, as well as the estimated operator dose of 2.7 Rem for this activity.

NRC Question 3
Provide clarification regarding the evaluation of the CRDMs as follows:

a.) What organization (Westinghouse?) prepared the original stress report for the Model L-106 CRDMs. What were the ASME Code Editions / Addenda's used for (1) stress analysis, and (2) fatigue analysis.

Ginna Response

The original 1960's Ginna Model L-106 CRDMs were provided by Westinghouse.
The code utilized for evaluation was the ASME 1965 edition with the summer 1966 addenda.

b.) Same question for the replacement Model L-106A CRDMs

Ginna Response

The replacement, equivalent, L-106A CRDMS were provided by Framatome ANP, Jeumont
The code utilized for stress and fatigue analysis was the ASME 1995 edition with the 1996 addenda.

c.) What organization compared the original and replacement models and determined that they were equivalent for EPU evaluation purposes.

Ginna Response

Ginna Station Plant Change Request (PCR) 2001-0042 provided equivalent model L-106 CRDM's. (The original model L-106 used a bolted connection at the joint of the "Rod Travel Housing" to the latch assembly housing. The equivalent CRDM utilizes an omega seal welded joint at this location similar to the L106-A configuration)
Westinghouse evaluated the acceptability and equivalency for uprate conditions.

d.) What organization evaluated the CRDMs for EPU loads. What is the document reference? What were the ASME Code references (see Question 1).

Ginna Response

Westinghouse evaluated the CRDMs for EPU loads. The evaluation is documented in CN-RCDA-04-81, "Evaluation of Model L106 CRDM and Capped Latch Housing for R.E. Ginna – Extended Power Uprate"

The code utilized was ASME 1995 edition with the 1996 addenda.

ATTACHMENT 6
QUESTIONS AND ANSWERS RESULTING FROM A FEBRUARY 8, 2006 CONFERENCE CALL

NRC Question 1

In the last paragraph of your response to RAI Question 1.a (see page 26 of Attachment 2) regarding Changes in Emergency and Abnormal Operating Procedures in your December 6, 2005, letter, it states:

"The DW resolution provided guidance supporting relocation of several E-0 automatic action verification steps to an attachment which can be performed as time permits allowing a more expeditious progression through the procedure and transition to the appropriate optimal recovery guideline."

Question: What items in the E-0 are being relocated and performed as time permits and how will the licensee verify that those items that are relocated would not prohibit the correct transition into the appropriate recovery procedures?

Ginna Response

The only transition in the steps identified by WOG for relocation to an attachment was the verification of secondary heat sink which contains a transition to FR-H.1 if AFW flow is not adequate. This was discussed in the WOG Direct Work Request. "Elimination of the transition to FR-H.1 in the E-0 step does not alter the ERG strategy since transfer to FR-H.1 will be made from the Critical Safety Function Status Tree once a transition from E-0 is reached. Since an enhanced E-0 will result in the operators reaching the diagnostic steps faster, a net time savings should be realized with respect to transfer to FR-H.1." However, it has been determined by operations personnel that the heat sink steps will not be relocated to the attachment. The verification/initiation of containment spray will also remain in the procedure. Additionally, all licensed operators are required to memorize the Red Path Summary for the critical safety functions and operators would notify the SRO if adequate AFW flow could not be established. Finally, there is a critical safety function Red Path Summary attachment as a reference in all appropriate Emergency Procedures.

The steps proposed for relocation to the attachment include the following automatic action verification steps:

- SI/RHR pumps running
- CNMT recirculation fans running
- Main Steam line isolation
- MFW isolation
- Service water pumps running
- CNMT isolation
- Component Cooling verification
- Check SI/RHR flow
- SI pump alignment verification
- CREATs actuation verification

Relocating these steps to the attachment is consistent with the WOG recommendation. There are no procedural transitions in the above listed steps.