APS

Scott A. Bauer
Department Leader
Regulatory Affairs
Palo Verde Nuclear
Generating Station

Tel: 623/393-5978
Fax: 623/393-5442
e-mail: sbauer@apsc.com

Mail Station 7636
P.O. Box 52034
Phoenix, AZ 85072-2034

102-05071- SAB/TNW/JAP/GAM
March 11, 2004

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555–0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit 2
Docket No. STN 50-529
Unit 2, Cycle 12 Startup Report

In accordance with Technical Requirements Manual (TRM) requirement T5.0.600.2.a(1), (2) and (3), Arizona Public Service Company (APS) is submitting a startup report for PVNGS Unit 2, Cycle 12. The NRC issued Operating License Amendment No. 149 for PVNGS Unit 2 on September 29, 2003, containing changes to support replacement of the steam generators and subsequent operation at an increased maximum power level of 3990 MWt. The Power Uprate (PUR)/Replacement Steam Generator (RSG) project for Unit 2 meets criteria (1) and (3) of TRM T5.0.600.2.a requiring a startup report. In addition, the Unit 2 Cycle 12 core consists of 100 fresh assemblies intermixed with 108 once-burned and 33 twice-burned irradiated assemblies that meets criteria (2) of TRM T5.0.600.2.a requiring a startup report. The fresh assemblies were designed utilizing a new three-enrichment assembly split. Using three different fresh assembly enrichments versus only using two enrichments enhances the PVNGS Unit 2 core design by providing both improved power peaking control and lower predicted crud deposition. The enclosed startup report addresses the tests that were performed to demonstrate that the unit operating conditions affected by these changes remain within design predictions and specifications.

Enclosure 1 contains a summary of the physics testing performed for the Unit 2, Cycle 12 startup, and Enclosure 2 contains a summary of the specific tests performed for PUR/RSG. Enclosure 3 contains some key plant parameter response graphs.

Some additional testing (steam generator moisture carryover and steam generator blowdown piping vibration measurements) as part of the PUR/RSG has not been completed. A supplement report will be submitted after this additional testing is complete.

IE26

No commitments are being made to the NRC by this letter.

If you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

TN Weber...
for SA Bauer

SAB/TNW/JAP/GAM/kg

Enclosure 1 – Unit 2, Cycle 12 Startup Report: Startup Physics Testing Summary
Enclosure 2 – Unit 2, Cycle 12 Startup Report: Steam Generator Replacement and Power Uprate Return to Service Testing Summary
Enclosure 3 – Unit 2, Cycle 12 Startup Report: Plant Response Graphs

cc:	B. S. Mallet	NRC Region IV Regional Administrator
	M. B. Fields	NRC NRR Project Manager
	N. L. Salgado	NRC Senior Resident Inspector for PVNGS

ENCLOSURE 1

Unit 2, Cycle 12 Startup Report:

Startup Physics Testing Summary

Introduction

The Palo Verde Nuclear Generating Station (PVNGS) Unit 2 Cycle 12 core consists of 100 fresh assemblies intermixed with 108 once and 33 twice-burned irradiated assemblies. The predicted cycle length is 466 EFPD. Reload Analyses shows that this core is typical of the most recent reload cores designed at PVNGS, although slightly shorter in cycle length due to the replacement of Steam Generators.

Cycle 12 initial criticality occurred at 1808 on December 12, 2003. Low Power Physics Testing (LPPT) began immediately following criticality and was completed the following day. Additionally, the resumption of commercial operations occurred on December 15, 2003. Power Ascension Testing followed and the unit reached 100% power on December 23, 2003.

LPPT consisted of:

All Rods Out (ARO), Hot Zero Power (HZP), Critical Boron Concentration
Isothermal Temperature Coefficient (ITC) Measurement
Control Element Assembly (CEA) Worth Measurement
Inverse Boron Worth Measurement

Power Ascension Testing, for model verification, consisted of:

Radial Power Distribution ~ 20% Rated Thermal Power (RTP)
Radial Power Distribution ~ 70% RTP
Axial Power Distribution ~ 70% RTP
Radial Power Distribution ~ 100% RTP
Axial Power Distribution ~ 100% RTP
Verification of the Cycle Independent Shape Annealing Matrix (CISAM)
Hot Full Power (HFP), ARO, Critical Boron Concentration.

Continuing Physics Testing includes the results of the 40 EFPD At-Power Moderator Temperature Coefficient test.

Test Acceptance Criteria

The following acceptance criteria apply to each of the tests performed during LPPT and Power Ascension:

Critical Boron Concentration (HZP)	± 50 ppm of predicted
ITC Measurement	
LPPT	± 3 pcm/°F of predicted
At-power (40 EFPD)	± 1.517 pcm/°F of predicted

Test Acceptance Criteria (continued)

CEA Testing	
Reference Group	± 10% of predicted
Test Group(s) (greater of)	± 15% of predicted or 100 pcm
Total Worth	± 10% of predicted
Inverse Boron Worth (IBW)	± 15 ppm/% ΔK/K of predicted
Radial Power Distribution ~20% RTP	± 10% of predicted for locations with a Relative Power Density (RPD) > 1.0
Flux Symmetry ~ 20% RTP	Within 10% of symmetric group average for instrumented locations with an RPD ≥ 1.0 and ± 0.1 RPD units for locations with an RPD < 1.0.
Radial Power Distribution ~70% RTP	± 0.1 RPD and Root Mean Square (RMS) ≤ 5%
Axial Power Distribution ~70% RTP	± 0.1 RPD and RMS ≤ 5%
Peaking Factors	± 10% of predicted
Radial Power Distribution ~100% RTP	± 0.1 RPD and RMS ≤ 5%
Axial Power Distribution ~ 100% RTP	± 0.1 RPD and RMS ≤ 5%
Peaking Factors	± 10% of predicted
CISAM Verification	
Axial Shape RMS Error	≤ 7.5%
Core Average Axial Shape Index (ASI) Error (absolute value)	≤ 0.075
Axial Form AFM Error (absolute value)	≤ 0.10
Critical Boron Concentration (HFP)	± 50 ppm of predicted

Low Power Physics Testing

All Rods Out (ARO) Critical Boron Concentration (CBC)

This test is performed by obtaining a set of reactor coolant system (RCS) boron samples at equilibrium conditions near ARO (CEA Group 5 ~ 130" withdrawn) and adjusting this concentration for the Group 5 residual reactivity worth. The measured RCS concentration was 1860 ppm, which was adjusted for an ARO condition to 1863 ppm. The design HZP ARO CBC is 1899 ppm. The difference of 36 ppm is within the acceptance criteria.

Isothermal Temperature Coefficient (ITC)

Raising and lowering the RCS temperature and measuring the associated changes in core reactivity performs this test. The measured ITC with Group 5 at ~ 129" withdrawn was -3.25 pcm/°F. The predicted ITC was -2.39 pcm/°F and was corrected to test conditions. The corrected ITC was -2.75 pcm/°F. The measured ITC met the acceptance criteria and satisfied the surveillance requirement of Technical Specification 3.1.4.1.

CEA Rod Worth Measurements

Rod worth was measured using the Rod Swap method. The Reference Group (regulating groups (RGs) 1 + 3) were diluted into the core. The worth of the reference group was exchanged with the worth of the test group. The results are summarized in the following Table:

CEA Group	Measured Worth (pcm)	Predicted Worth (pcm)	% Difference	Acceptance Criteria
Reference Group (RG1 + RG3)	-1291.1	-1324.2	2.56	≤10%
Test Groups:				
SD 'B' #9, #10 & #16	-1310.0	-1197.6	8.58	≤15%
RG5, SD 'A' #2 & #20	-1107.5	-1149.6	3.80	≤15%
RG2, RG4 & RG5	-1087.0	-1055.6	2.89	≤15%
RG5, SD 'A' #3 & #19	-1118.3	-1155.7	3.34	≤15%
SD 'B' #6 & #7	-1146.1	-1179.2	2.89	≤15%
Total CEA Worth	-7060.0	-7061.9	0.03	≤10%

All test results met the acceptance criteria.

Inverse Boron Worth (IBW)

The IBW was determined by obtaining the measured worth of the CEA Reference Group and the change in the CBC from the dilution of the Reference Group to the

control element assembly (CEA) lower electrical limit (LEL). The measured IBW was 134.0 ppm/% ΔK/K. The predicted IBW was 131.3 ppm/% ΔK/K. The acceptance criterion was met.

Power Ascension Testing

Flux Symmetry Verification ~ 20% RTP

Obtaining a flux map, by processing a CECOR snapshot, and comparing symmetrical Relative Power Densities (RPD) performs this test. All deviations from the average of the instrumented powers were well within 10% or 0.1 relative power density (RPD) units.

Radial Power Distribution (RPD) and Flux Symmetry ~ 20% RTP

A comparison of predicted and measured RPDs was made using data from ROCS and CECOR at ~ 20% RTP. The maximum difference for assemblies with an RPD greater than or equal to 1.0 was less than the acceptance criteria of 10%. Measured powers in symmetric, instrumented assemblies were within 10% of the symmetric group average for assemblies with RPD's greater than 1.0 and within 0.1 RPD units for assemblies with an RPD less than 1.0.

Radial and Axial Power Distributions ~ 70% RTP

A comparison of predicted and measured RPD's was made using data from ROCS and CECOR at ~ 70% RTP. Measured versus predicted RPD's were within the requirement of ± 0.1 RPD and a root mean square (RMS) of ≤ 5% for both the radial and axial comparisons.

Radial and Axial Power Distributions and Peaking Factor Comparisons ~ 100% RTP

A comparison of predicted and measured RPDs was made using data from ROCS and CECOR at ~ 100% RTP. Measured versus predicted RPD's were within the requirement of ± 0.1 RPD and an RMS of ≤ 5% for both the Radial and Axial comparisons. Additionally, CECOR and ROCS comparisons of the Peaking Factors were made. The acceptance criteria of ± 10% were also met.

Verification of the Cycle Independent Shape Annealing Matrix (CISAM)

Evaluation of the CEFAST output data was performed to validate the use of the CISAM in the plant Core Protection Calculator (CPC). The requirement that the axial shape index (ASI) RMS error be ≤ 7.5% for each CPC channel was met. Additionally, the absolute values of the core average ASI Error and the axial form AFM error were ≤ 0.075 and ≤ 0.10, respectively.

Critical Boron Concentration (CBC) at Hot Full Power (HFP)

The requirement for the measured versus predicted CBC at HFP is ± 50 ppm. This acceptance criterion was met for the Power Ascension Testing, as the predicted HFP, equilibrium Xenon, CBC was 1283.5 ppm and the measured value was 1267 ppm.

Continuing Physics Testing

40 EFPD Moderator Temperature Coefficient (MTC) Test

This test is performed by measuring the at-power Isothermal Temperature Coefficient to verify that the MTC is within allowed Technical Specification limits. The measured MTC was -14.07 pcm/°F. The predicted MTC was -14.12 pcm/°F, after adjusting the prediction to test conditions. The difference of 0.05 pcm/°F is within the acceptance criterion.

ENCLOSURE 2

Unit 2, Cycle 12 Startup Report:

Steam Generator Replacement and Power Uprate Return to Service Testing Summary

Introduction

The scope and acceptance criteria for the Startup Test Program (SUTP) for the Power Uprate (PUR)/Replacement Steam Generator (RSG) were developed in three stages.

In stage 1, an initial assessment of required tests for initial startup of Chapter 14 (Initial Test Program) to the Updated Final Safety Analysis Report (UFSAR) and Combustion Engineering Standard Safety Analysis Report (CESSAR) was completed in conjunction with industry experience reviews for several plants' post-RSG testing. These assessments provided an initial list of tests to be included in the program.

Stage 2 consisted of a more in-depth screening of the testing and development of preliminary acceptance criteria.

Stage 3 included a detailed, independent engineering assessment of the testing required for the PUR/RSG project. This assessment was accomplished based on an independent review of plant systems relative to PUR/RSG impacts versus UFSAR Chapter 14. The results of the review were then reconciled with the stage 2 reviews to define the final project testing.

The three stage process assured that a comprehensive start-up test program was implemented relative to the modifications. The SUTP demonstrated that the unit operating conditions affected by the SGR/PUR are within design expectations and specifications.

Several of the tests identified were addressed by pre-existing surveillance tests and met all acceptance criteria. Examples include:

- AFW flow to S/G test
- CEA drop time test

The following specific tests and activities were performed as part of the SUTP:

- Steam generator replacement project (SGRP) spillover test
- Hot gap program
- SGRP steam generator blowdown flow test
- SGRP AFW water hammer test
- Reactor coolant system flow verification following steam generator replacement
- Reactor coolant system heat loss measurement following steam generator replacement
- SGRP steady state vibration test
- SGRP control system checkout test
- SGRP load transient test
- Post SGR biological shield (bio-shield) survey analysis

Additionally, two SUTP tests (steam generator moisture carryover measurement and stream generator blowdown piping vibration measurement) have not been completed at the time of this submittal. When these tests have been completed a supplement report will be submitted.

SGRP Spillover Test

The SGRP spillover test objective was to obtain and verify the elevations at which the hot and cold legs overflow from their respective legs into the bowls of the steam generators to ensure spillover points are acceptable for future midloop operations. This test was performed on November 18, 2003. During the initial reactor coolant system fill prior to core reload, the lowest elevation at which spillover occurred was on the #1 SG "A" cold leg at an elevation of 101' 11.5". This result was within the expected range of 102' ± 2".

Hot Gap Program

The objective of the hot gap program was to validate that thermal movements of components installed or modified by the SGRP are as expected or are otherwise acceptable (by engineering evaluation or by physical changes).

The acceptance criteria varied with component; but, in general:

- No binding
- Bumper gaps not greater that design values
- Snubber strokes within design tolerances

At ambient conditions and at various temperature plateaus (170 -200 °F, 350 - 400 °F, 565 °F) during the Reactor Coolant System heatup, the following activities were performed:

- Look for binding.
- Adjust shims if necessary to preclude binding at elevated temperatures.
- Adjust shims to approach design gaps at normal operating temperature (NOT).
- Address any anomalies with engineering evaluations or physical changes.

Shims were added to two Feedwater piping bumpers, two Downcomer Feedwater (DCFW) piping upper bumpers, two DCFW piping lower bumpers and two Main Steam piping shim bars. Insulation was reworked at some primary pressure taps and lower level taps.

Tubing/tubing supports were reworked at several locations to preclude contact with the SG insulation.

Engineering evaluations were made where bumper gaps were smaller than specified and bumper component offsets were larger than specified. Validation that binding did not occur was made for each of these cases.

All acceptance criteria were met.

SGRP, Steam Generator Blowdown Flow Test

The test objectives were to verify that the revamped blowdown piping and sampling system with the Replacement Steam Generators function as designed. The test was performed in 3 sections:

1. Verify the new wet lay-up recirculation flow path.
2. Verify the new downcomer region blowdown flow path.
3. Verify the new blowdown sampling point flow paths.

The following acceptance criteria applied to each of the sections above:

1. Flow through the wet lay-up sparger line (no specific design value).
2. Flow through the downcomer region blowdown flow paths shall be within 15% of the measured flow through the hot leg blowdown flow paths (Normal, Abnormal, and High Rate to Condenser).
3. Flow rate through the new sampling lines was at least 1.95 gpm.

On November 29, 2003 with the steam generators (SGs) filled and depressurized in Mode 5 conditions, flow through the wet lay-up sparger line was verified on both SGs. SG1 flow was 33.4 gpm. SG2 Flow was 29.0 gpm.

On December 11, 2003 under Mode 3 Normal Operating Pressure and Temperature (NOP/NOT) conditions, blowdown flow was measured through the downcomer and hot leg blowdown flow paths to the condenser on both SGs. The following table presents the results of the blowdown flow measurements.

U2 RSG Blowdown Flow Rates (1000 lbm/hr)

Line Up	Hot Leg	Downcomer	% Difference
SG1 – Normal to Condenser	82.2	77.6	5.6
SG1 – Abnormal to Condenser	155.6	166.5	7.0
SG1 – High Rate to Condenser	604.4	896.0	48.2
SG2 – Normal to Condenser	82.5	87.9	6.5
SG2 – Abnormal to Condenser	164.4	185.5	12.8
SG2 – High Rate to Condenser	586.0	856.0	46.1

Downcomer region blowdown in normal and abnormal rate on both SGs passed. High rate blowdown failed on both SGs. A Test Exception Report and a Condition Report Disposition Request (CRDR) were written. Upon further review of design documentation, it was determined that the downcomer was predicted to have 47% more flow than the hot leg in the high rate configuration. Test results were acceptable with the revised criteria. Although it is not intended to utilize the downcomer flow path in the high rate configuration, its design could support high rate blowdown and this test was used to validate that design. Controls have been put in place to ensure that the downcomer high rate flow path is not used. Chemistry Technical Support verified that this flow path is not necessary for SG chemistry control.

On December 11, 2003 under Mode 3 NOP/NOT conditions flow was measured through the new sample lines. The results are listed below:

- SG1 Downcomer sample path: 2.17 gpm
- SG1 Downcomer Blowdown sample path: 1.97 gpm
- SG2 Downcomer sample path: 2.10 gpm
- SG2 Downcomer Blowdown sample path: 2.18 gpm

New sampling line flow rates met the acceptance criteria on both SGs.

Reactor Coolant System Flow Verification Following Steam Generator Replacement

The test objective was to determine the reactor coolant system (RCS) flow rate using the reactor coolant pump (RCP) delta P method.

The acceptance criteria were the following:

- The actual RCS mass flow rate > 155.8 E6 lbm/hr (Technical Specification 3.4.1).
- The RCS volumetric flow rate > 466,500 gpm.
- The RCS volumetric flow rate < 496,400 gpm (fuel fretting limit).

RCS Flow was determined to be 474,998.5 gpm (174.6 E6 lbm/hr) on December 11, 2003 under Mode 3 NOP/NOT conditions.

All acceptance criteria were met.

Reactor Coolant System Heat Loss Measurement Following Steam Generator Replacement

The objective of this procedure was to measure the Reactor Coolant System (RCS)

heat loss at the 565 °F (NOT) and 2250 psia (NOP) test plateau and to determine the Core Operating Limit Supervisory System (COLSS) heat loss constants.

The acceptance criteria were the following:

- The RCS heat loss has been determined to be < 7.1 MBTU/hr.
- The maximum Containment Air Temperature indication < 117 °F.

The Reactor Coolant System was stabilized and maintained at NOP/NOT conditions. The sources of energy addition, removal and losses from the Reactor Coolant System were measured. To reduce the number of quantities being measured, steam generator blowdown and sampling were secured. To accurately measure pressurizer heater input, backup heaters were operated in MANUAL since the proportional heater output is variable. Containment heat load was measured by determining the heat removed by Nuclear Cooling Water (NC) to the CEDM Cooling coils and Normal Chilled Water (WC) through the Normal Containment ACU cooling coils.

On December 12, 2003, measured RCS Heat Loss was determined to be 6.380 MBTU/hr. Maximum Containment Air Temperature observed during the test was 95.64 °F. All acceptance criteria were met.

SGRP, Auxiliary Feedwater (AFW) Water Hammer Test

The objective of this test was to verify that the revamped AFW piping system and the Replacement Steam Generator (RSG) feed ring are not damaged by full flow injection of Auxiliary Feedwater.

The acceptance criteria were the following:

- No audible sounds indicative of thermal-hydraulic phenomena (water hammer) detected during the performance of this test.
- Post-test visual inspection of the auxiliary feedwater piping reveals no visual damage to pipe, hangers, insulation or other structures.
- Post-test visual inspection of the steam generator internal feed ring shows no effects of damaging water hammer.

On December 11, 2003 at Mode 3 Normal Operating Pressure and Temperature (NOP/NOT), Steam Generator #1 water level was lowered below the feed ring elevation, thus producing the conditions that could lead to drainage of the feed ring. Full flow injection of the Auxiliary Feedwater Pumps "A" and "B" was then initiated. Individuals in the field monitored for observable indications of water hammer.

- No audible sounds of water hammer were detected locally near S/G #1 downcomer line, or locally in the AFW pump rooms.

- The S/G #1 downcomer line was walked down from the S/G #1 downcomer feedwater nozzle to the containment penetration. All piping supports appeared to be unaffected by the test. No abnormalities were noted.

On February 27, 2004 during a short notice outage, the secondary side of S/G # 1 was opened in order to perform an inspection of the tube bundle to identify the source of a primary to secondary leak. An inspection of the downcomer feed ring was performed in conjunction with the tube bundle inspection.

Each of the following downcomer feed ring components was inspected for visible signs of deformation, cracking, or other damage that could result from a water hammer event. All of the components were found in satisfactory condition without any signs of deformation, cracking or other damage:

- Feed ring piping
- Feed ring discharge nozzles
- Feed ring inlet piping (also known as the gooseneck)
- Feed ring supports, including U-bolts and attachment hardware

All acceptance criteria were met.

SGRP, Steady State Vibration Test

The test objectives were the following:

- To verify that steady state flow induced piping vibrations values are within the acceptable limits for the Replacement Steam Generators and associated piping systems that were revamped.
- To perform vibration data collection for a representative sample of principal balance of plant high energy systems to evaluate for adverse impact from the RSGs and/or the 2.9% increase in thermal power.
- To perform vibration data collection for the main turbine stop and control valves to evaluate for adverse impact due to the change to turbine full arc admission operation.

The acceptance criterion was that the piping vibration velocity was less than 2.5 inches per second (ips).

On December 11, 2003, vibration levels were measured on sixteen representative points on the primary systems under Mode 3 NOP/NOT conditions. All of the points were well below the acceptance criteria of 2.5 ips. The highest value recorded was 0.296 ips on the RCS 2A loop drain valve.

On December 15, 2003 at the 20% power test plateau, vibration levels were measured on the new downcomer blowdown valve actuators in the normal rate flow alignment. All of the points were well below the acceptance criteria of 2.5 ips. The highest value recorded was 0.056 ips.

On December 29, 2003 at 100% power, vibration levels were measured on numerous balance of plant locations and the main turbine stop and control valves. All of the points were below the acceptance criteria of 2.5 ips. The highest value recorded was 1.436 ips on the SG #2 Steam Line 2 Drip Pot.

Thus, there were no restrictions for the power ascension due to measured vibration data.

Additionally, further vibration data gathering will be performed on several portions of the steam generator blowdown piping/valves and this information will be submitted as a supplement to this report.

SGRP Control System Checkout Test

The test objectives were the following:

- To demonstrate that the feedwater control systems maintains steam generator levels within acceptable bands during steady state conditions and at various plateaus during power ascension.
- To demonstrate that the feedwater control systems maintains steam generator levels within acceptable bands when the setpoint is varied by an increasing or decreasing 5% step change.
- To demonstrate that the Feedwater Control System (FWCS), Steam Bypass Control System (SBCS), Pressurizer Level Control System (PLCS), Reactor Regulating System (RRS)(in auto sequential), and Pressurizer Pressure Control System (PPCS) maintains plant parameters within acceptable tolerances of their program values during power maneuvers.

The acceptance criteria were the following:

- The reactor did not trip as a direct result of this test.
- The Main Turbine did not trip as a direct result of this test.
- No Engineered Safety Features Actuation System (ESFAS) actuations occurred as a direct result of this test.
- No Steam Generator safety valves lifted as a direct result of this test.
- No Primary safety valves lifted as a direct result of this test.
- The FWCS controls steam generator levels to within ± 2% narrow range (NR) of the control setpoint when operating at steady state conditions.
- The FWCS controls steam generator levels to within ± 2% NR of control setpoint

after stabilization period to both 5% increase and decrease step change.

- RRS maintains/restores RCS average temperature (T_{avg}) to within ±3 °F of RCS reference temperature (T_{ref}).
- SBCS maintains/restores steam header pressure to within ± 15 psia of setpoint.
- PLCS maintains/restores pressurizer level to within ± 2% of setpoint.
- PPCS maintains/restores pressurizer pressure to within ± 15 psia of setpoint or the initial value at test initiation.

On December 16, 2003 the Reactor was stabilized at just under 20% power and the Steam Generator water level was varied in 5% steps, on one steam generator at a time, and then the control systems were evaluated.

On December 19, 2003 the Reactor was stabilized at just under 70% power and the Steam Generator water level was varied in 5% steps, on one steam generator at a time, and then the control systems were evaluated.

All measured control system parameters met acceptance criteria.

SGRP Load Transient Test

<u>5% per Minute Ramp and 10% Step Change</u>

The objective of this portion of the test was to demonstrate that unit load decreases, by steps and ramps, at the 70% power plateau can be performed at the Nuclear Steam Supply System (NSSS) design rates with key plant parameters remaining within acceptance criteria.

The acceptance criteria were the following:

- The reactor did not trip as a direct result of this test.
- The Main Turbine did not trip as a direct result of this test.
- No ESFAS actuations occurred as a direct result of this test.
- No Steam Generator safety valves lifted as a direct result of this test.
- No Primary safety valves lifted as a direct result of this test.
- For transients of greater than 15% power, the control systems response maintain plant process parameters within their operating band and minimizes process overshoot as much as practical.
- There will be no sustained process oscillations during any steady state or design basis maneuvering operation.

- With all control systems in the automatic mode, none of the following design basis NSSS maneuvering transients will cause a reactor trip:
    - Steady state operations below 15%.
    - Steady state operations between 15% and 100% power using economizer feedwater control valves.
    - 5% per minute turbine load ramps and reductions between 15% and 100% power.
    - 10% turbine load steps between 15% and 100% power.
    - Loss of one of two operating FW pumps.

On December 19, 2003 at the 70% power level, power was reduced 5%/minute to approximately 65% and stabilized at that point. Data was taken and the Control Element Assemblies (CEAs) were borated out of the core.

After the stabilization period, the unit performed a 10% step drop in turbine load to reduce reactor power to ~ 55%. The unit was stabilized, data taken, and the CEAs borated out of the core again. Figures 1 through 4 in Attachment 3 show the response of Steam Generator pressure and level for each steam generator, T_{avg} and T_{ref}, and Pressurizer pressure and level for this test.

All acceptance criteria were met for the ramp and step change maneuvering transients.

Following successful completion of the 10% step, the unit increased power to the 95-98% plateau.

Reactor Power Cutback, Loss of Feedpump

The objective of this portion of the test was to demonstrate the unit responds to a Reactor Power Cutback per design at the 95-98% plateau with key plant parameters remaining within acceptance criteria.

The acceptance criteria were the following:

- The reactor did not trip as a direct result of this test.
- The Main Turbine did not trip as a direct result of this test.
- No ESFAS actuations occurred as a direct result of this test.
- No Steam Generator safety valves lifted as a direct result of this test.
- No Primary safety valves lifted as a direct result of this test.
- The control systems' response maintain plant process parameters within their operating band and minimizes process overshoot as much as practical.

- With all control systems in the automatic mode, the NSSS maneuvering transient will not cause a reactor trip.

- There will be no sustained process oscillations during any steady state or design basis maneuvering operations.

On December 21, 2003 at the 97% power plateau, the unit was subjected to a manual Reactor Power Cutback without tripping either main feedpump or the Main Generator. 40AO-9ZZ09, Reactor Power Cutback (Loss of Feedpump) procedure was used to stabilize the plant.

Figures 5 through 8 in Attachment 3 show the response of Steam Generator pressure and level for each steam generator, T_{avg} and T_{ref}, and Pressurizer pressure and level for this test.

All measured control system parameters met acceptance criteria.

Post SGR Biological Shield (Bio-Shield) Survey Analysis

The objectives of this survey were the following:

- Ensure that the restored sections of the bio-shield wall meet the effectiveness criteria initially established within the UFSAR.

- Ensure that selected UFSAR radiation zones in the Containment and Auxiliary Buildings were still within tolerance as a result of the power uprate.

The acceptance criteria for the survey were the following:

- There were no streaming radiation paths along the restored section of the Steam Generator #1 D-ring bio-shield wall that had been removed and restored.

- All selected bio-shield measurements taken within the Containment Building were comparable to historical radiation levels when compared to the original bio-shield survey and pre-shutdown radiation levels. All radiation levels were within specified UFSAR radiation zones for each applicable area.

This comparison is consistent with the guidance specified in the CESSAR Section 14.0 Initial Test Program, under sub-section 14.2.12.4.1, Low Power Biological Shield Survey Test.

Prior to the shutdown of Unit 2, survey locations were selected based on the original bio-shield measurements that had been performed during the initial power ascension testing in 1986. These locations were annotated with locator tags consistent with the system used during the original bio-shield survey. Additional radiation level

measurements were also performed in the vicinity of bio-shield wall removals. Prior to shutdown and the bio-shield modifications, these pre-selected locations were surveyed. After the unit reached 100% power, these same locations were re-surveyed and a comparison of the pre and post conditions was made. The survey results showed that gamma and neutron dose rates were very similar to the previous measurements. Several noticeable dose rate reductions were seen. This can be attributed to the removal of the old steam generators.

After reviewing the survey data, it was determined that the power uprate did not adversely affect or alter the effectiveness of the bio-shield wall to perform its intended function. The survey results showed that the restored sections of the bio-shield wall also meet the effectiveness criteria initially established within the UFSAR.

All acceptance criteria were met.

ENCLOSURE 3

Unit 2, Cycle 12 Startup Report:

Plant Response Graphs

Figure 1

Unit 2 10% Step Decrease 12/19/03

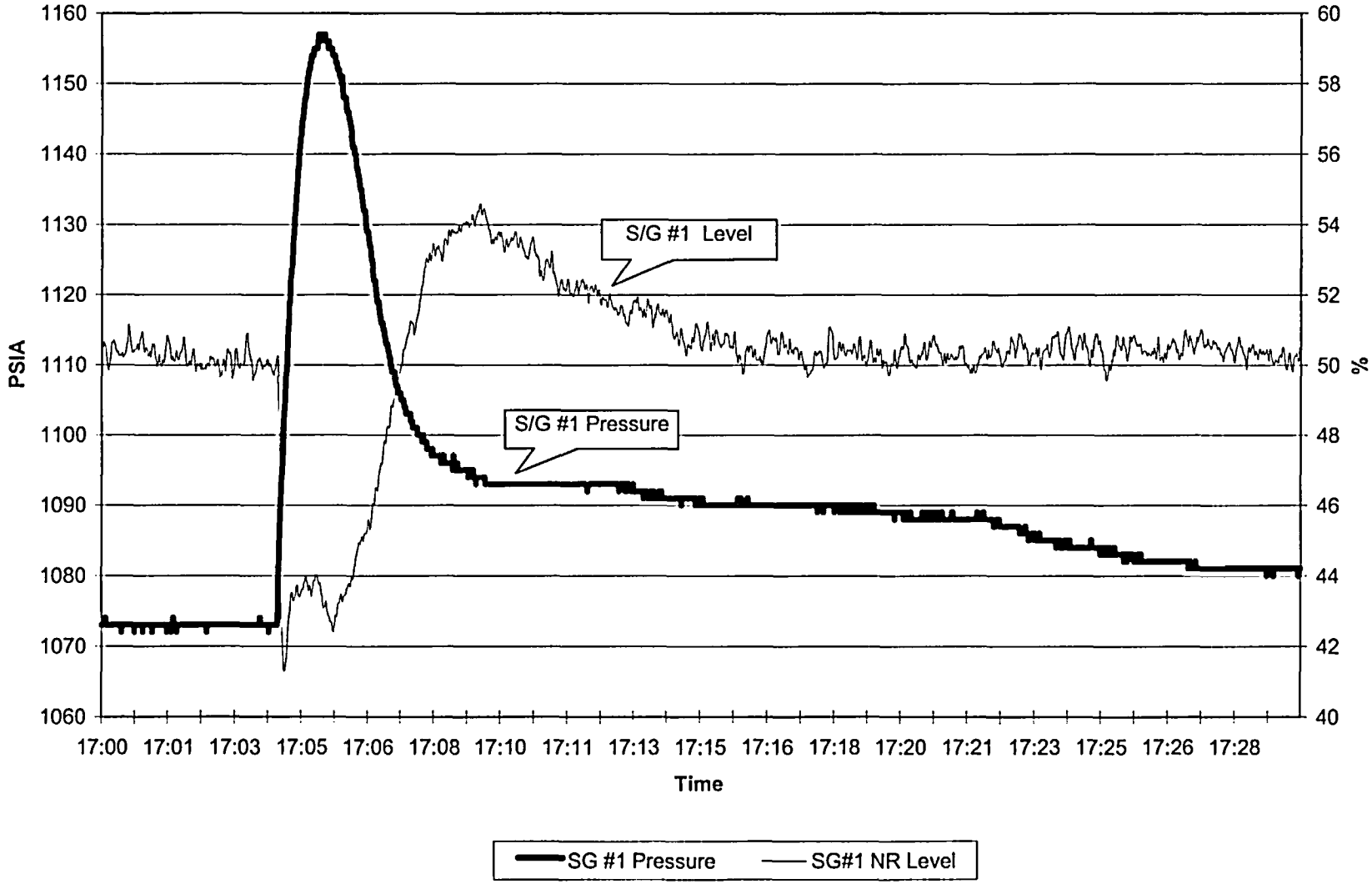


Figure 2

Unit 2 10% Step Decrease 12/19/03

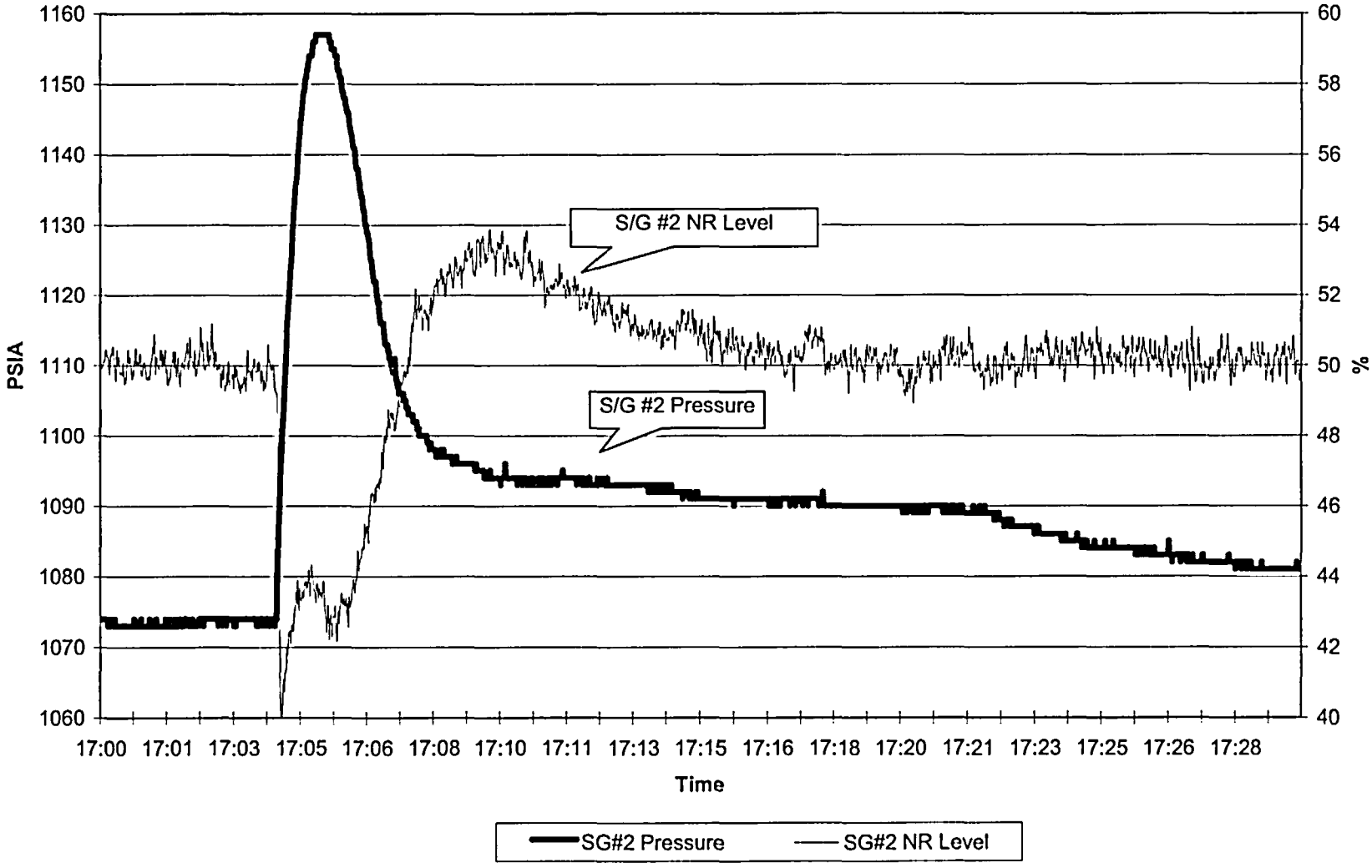


Figure 3

Unit 2 10% Step Decrease 12/19/03

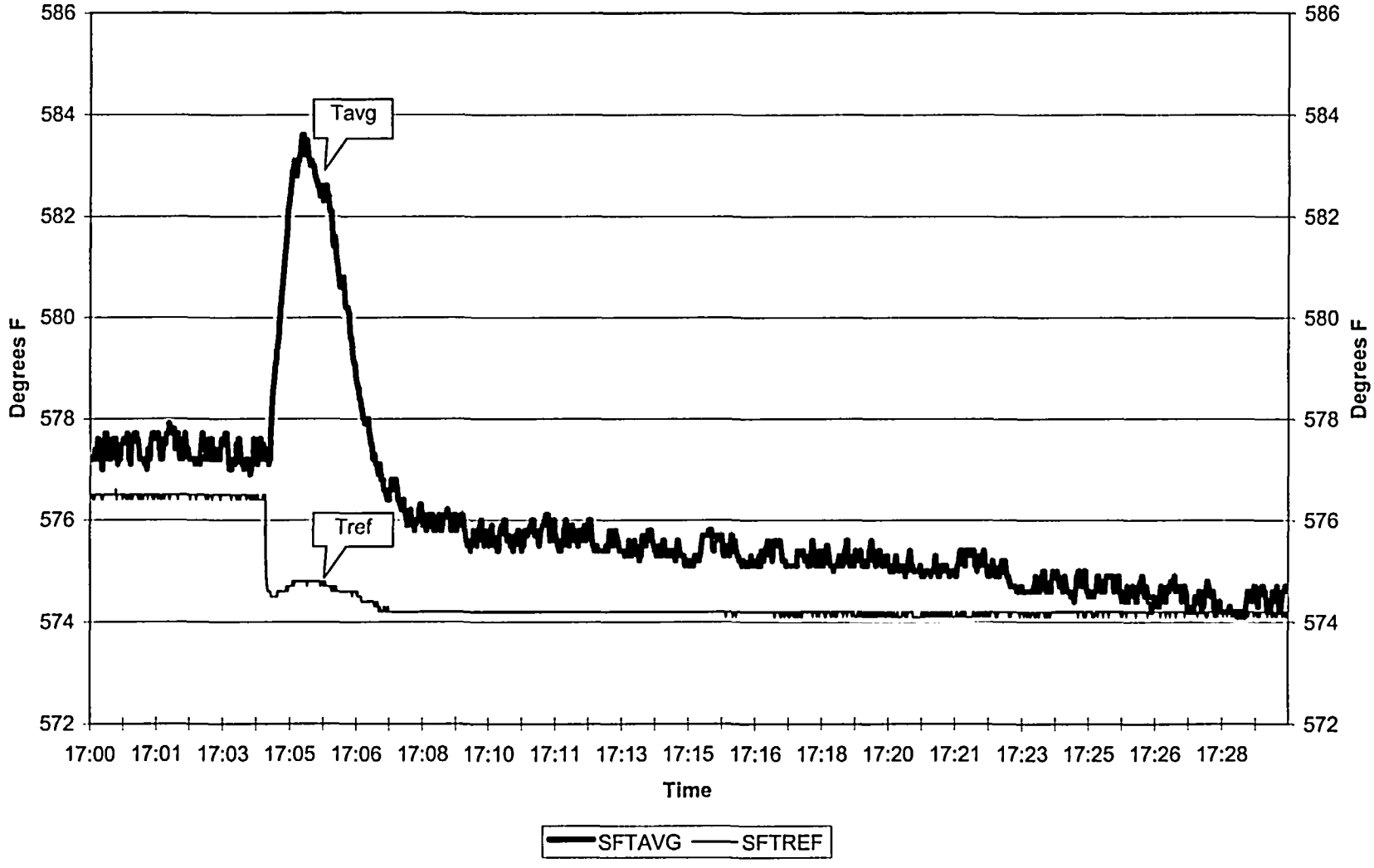


Figure 4

Unit 2 10% Step Decrease 12/19/03

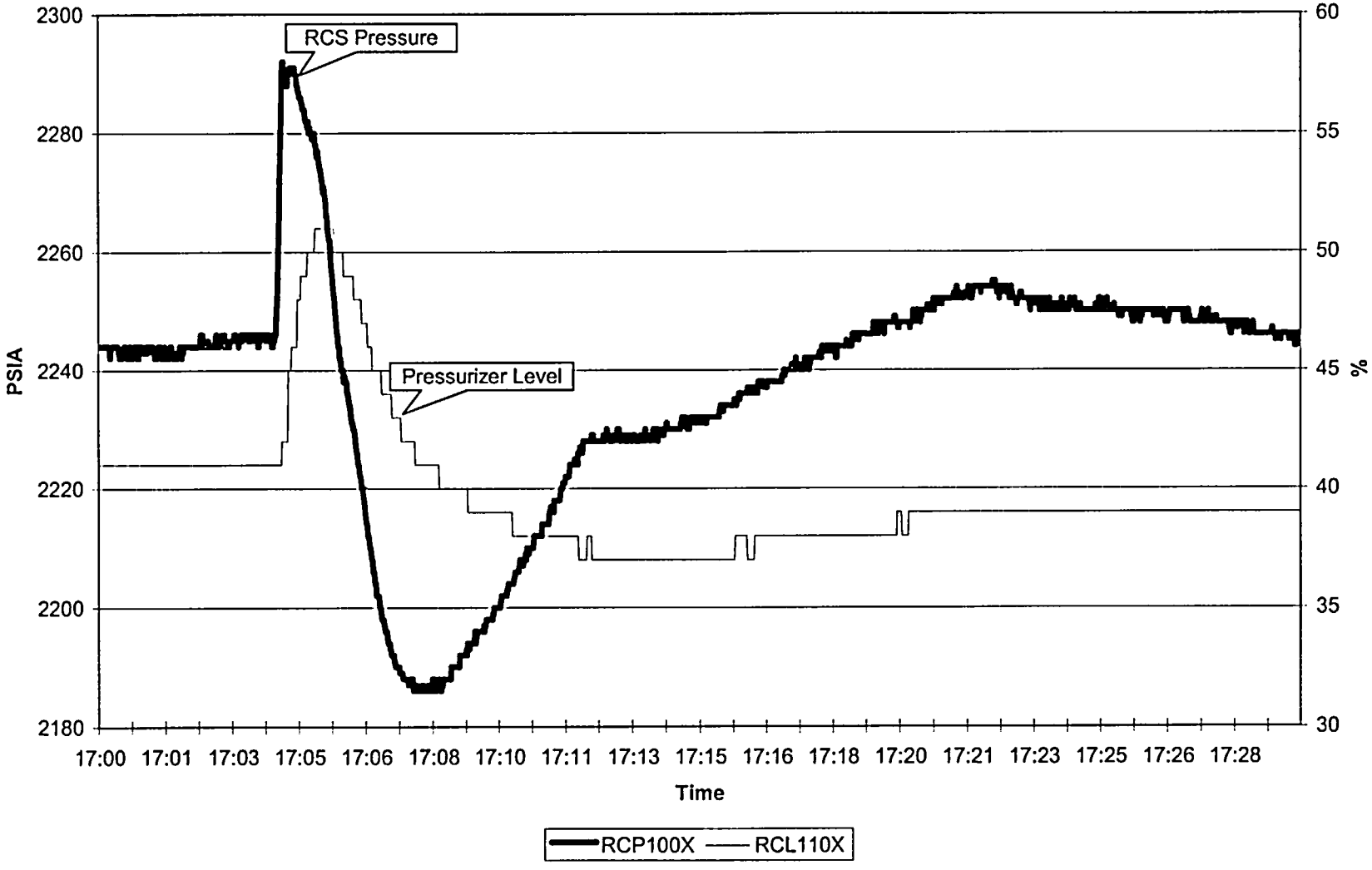


Figure 5

Unit 2 Reactor Power Cutback 12/21/03

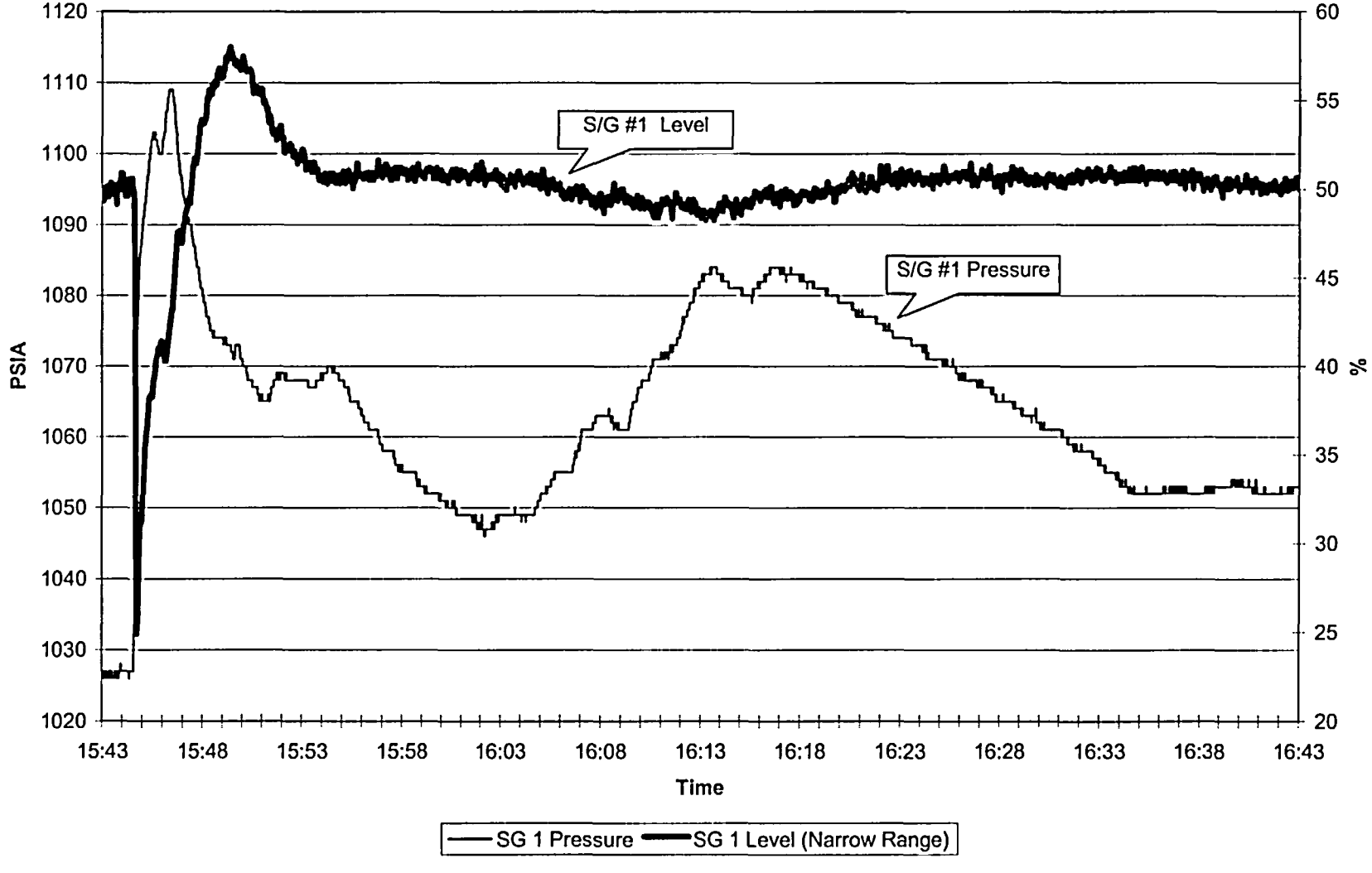


Figure 6

Unit 2 Reactor Power Cutback 12/21/03

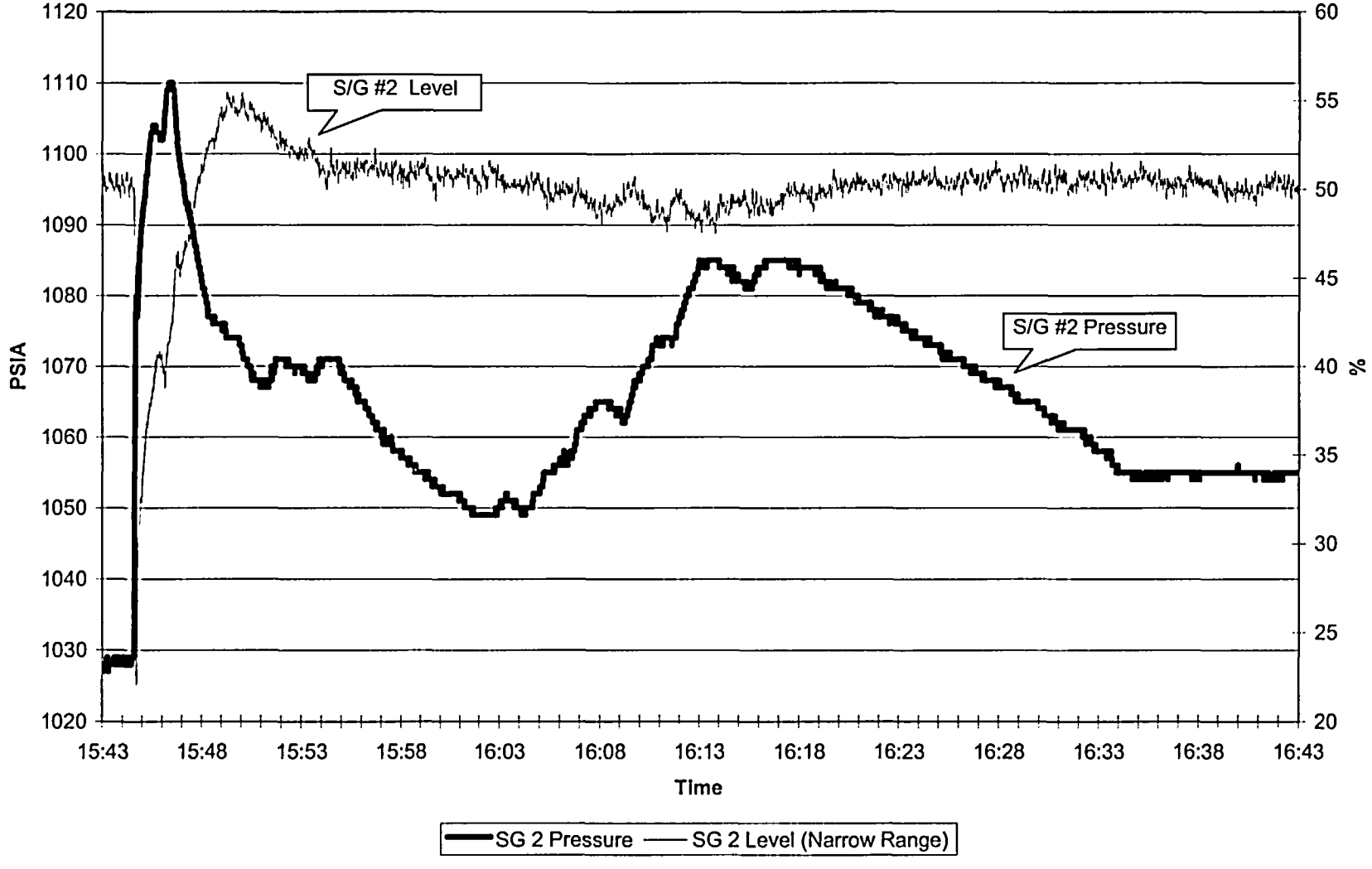


Figure 7

Unit 2 Reactor Power Cutback 12/21/03

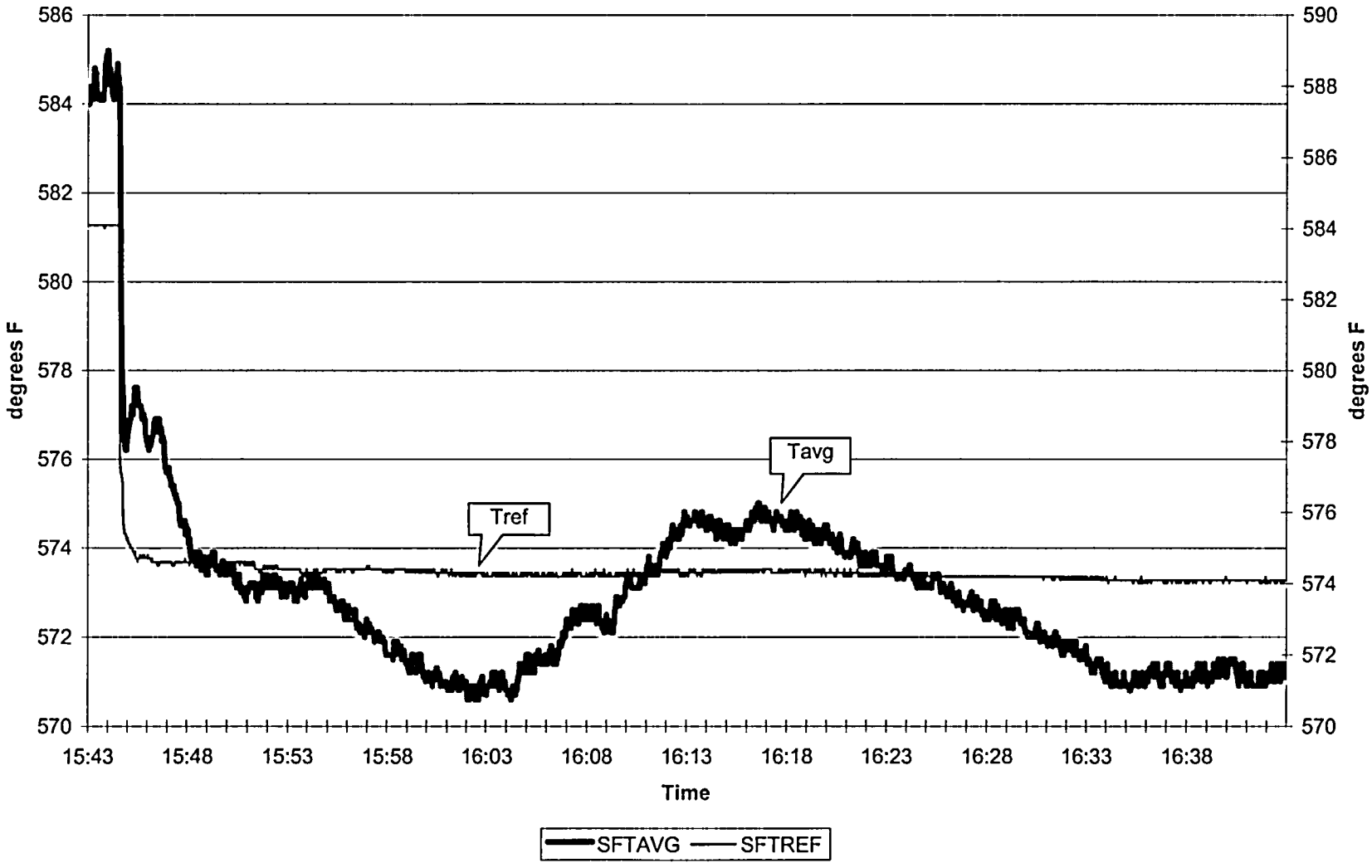
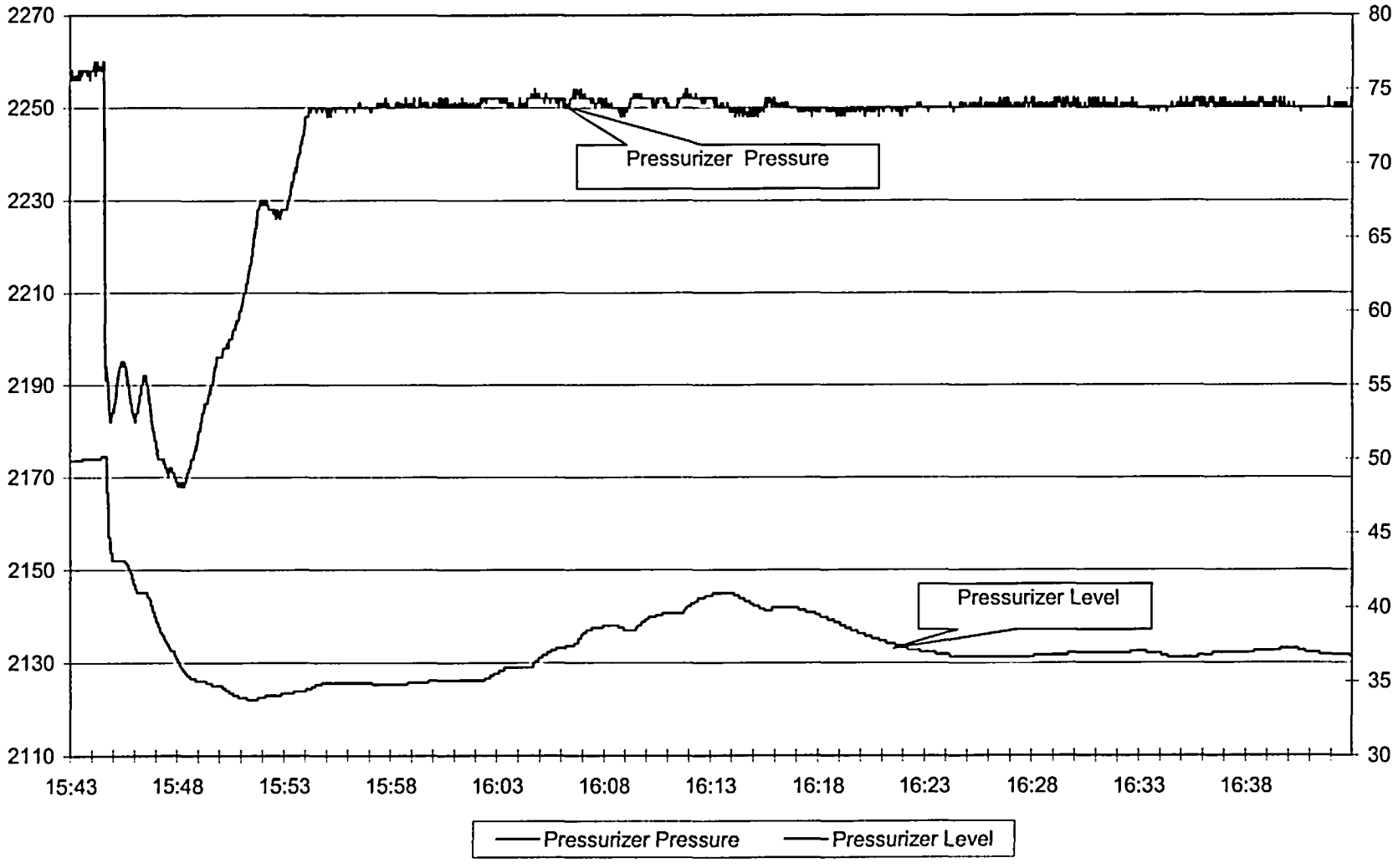


Figure 8

Unit 2 Reactor Power Cutback 12/21/03