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Constellation Energy
Generation Group

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U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

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

Startup Test Report for the R.E. Ginna Nuclear Power Plant Extended Power Uprate

In accordance with the requirements of the R.E. Ginna Nuclear Plant UFSAR, please find attached the Extended Power Uprate Startup Test Report which is hereby submitted by R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC).

If you should have any questions regarding this submittal, please contact Robert Randall at (585) 771-5219.

Very truly yours,

Mary G. Korsnick

Mary G. Korsnick

Attachment: Startup Test Report for the R.E. Ginna Nuclear Power Plant Extended Power Uprate

cc: S. J. Collins, NRC
D. V. Pickett, NRC
Resident Inspector, NRC

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Startup Test Report for the R.E. Ginna Nuclear Power Plant
Extended Power Uprate

Introduction

The R.E. Ginna Nuclear Power Plant (Ginna) Extended Power Uprate (EPU) power ascension test plan was a comprehensive plan that incorporated the design predictions from the EPU analyses, operating experience from the nuclear industry for other power uprates, post-modification testing for the plant modifications installed, and the plant surveillance testing required by technical specifications. During the EPU start-up, power was increased in a slow and deliberate manner, stopping at pre-determined power levels for steady-state data gathering and formal parameter evaluation. The typical post-refueling power plateaus were used until the pre-EPU full power condition was attained at approximately 85% of the EPU power level (1520 MWt). Additional equipment and plant transient testing were performed at approximately 30% and 50% of the EPU power level as discussed later to verify expected component, system and integrated plant performance. A summary of the Power Ascension Test Plan is provided in Table 1. Figure 1 provides a plot of the plant power level as a function of time until the full EPU power was reached.

Prior to exceeding previous licensed core thermal power of 1520 MWt, the steady-state data gathered at the pre-determined power plateaus and transient data gathered during the specified transient tests at low power, as well as observations of the slow, but dynamic power increases between the power plateaus, allowed verification of the performance of the EPU modifications. In particular, by comparison of the plant data with pre-determined acceptance criteria, the test plan provided assurance that unintended interactions between the various modifications had not occurred.

Once at approximately 85% of EPU power (1520 MWt), power was slowly and deliberately increased through 5 additional Test Conditions, each differing by approximately 3% of the EPU rated thermal power. Again, both dynamic performance during the ascension and steady-state performance for each Test Condition was monitored, documented and evaluated against pre-determined acceptance criteria.

Following each increase in power level, test data was evaluated against its performance acceptance criteria (i.e., design predictions or limits). If the test data satisfied the acceptance criteria then system and component performance were considered to have complied with their design requirements.

In addition to the steady-state parameter data gathered and evaluated at each test condition, and the dynamic parameter response data gathered and evaluated during the ascension between test conditions, several transient tests were also performed. These tests are listed and described in Table 2 below. These transient tests provided additional confidence in the validity of the analytical models and assumptions used in the analysis of plant modifications and integrated plant response to transients. Transient test data was compared against predictions provided by the same analytical models used in design verification for EPU. Any differences between predictions and test data were evaluated and reconciled before proceeding with the power ascension.

Specifically, hydraulic interactions between the new feed pumps and modified feed regulating valves, as well as the impact of the higher main feed flow and the associated increased piping pressure loss were evaluated. Individual control systems such as steam generator level control and moisture separator reheater (MSR) and feedwater heater drain level control were optimized for the new conditions as required. The transient tests adequately identified any unanticipated adverse system interactions and allowed them to be corrected in a timely fashion prior to full power operation at the uprated conditions. What follows is a summary level description of the results of the Ginna EPU Power Ascension Test Plan.

Figure 1

EPU Power Ascension from the 2006 Refueling Outage

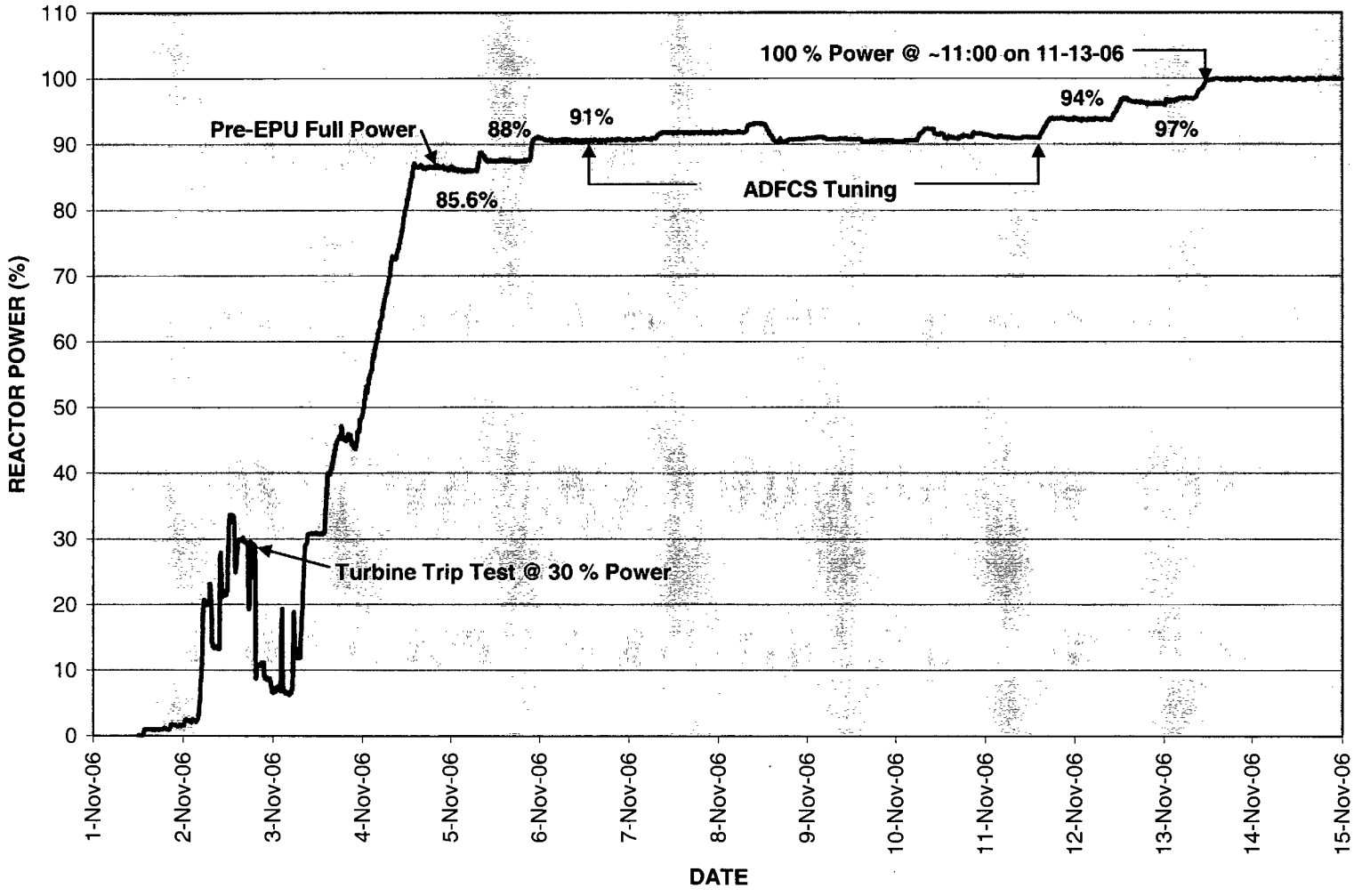


Table 1
Ginna Extended Power Uprate Power Ascension Test Plan

Test / Modification	Test Description	Prior To Start up	Rated Thermal Power - % of 1775 MWt																						
			0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	88	91	94	97	100
Nuclear Steam Supply System (NSSS) Data Record	Data Collection						X		X									X		X	X	X	X	X	X
Balance of Plant Data Record	Data Collection						X		X									X		X	X	X	X	X	X
Transient Data Record	Data Collection						X		X									X		X	X	X	X	X	X
Core Map	Power Distribution and COLR Parameters								X											X			X		X
NSSS Calorimetric and Power Range Channel Adjustment	Verify Thermal Power and Adjust Nuclear Instrumentation						X		X				X					X		X	X	X	X	X	X

Table 1
Ginna Extended Power Uprate Power Ascension Test Plan

Test / Modification	Test Description	Prior To Start up	Rated Thermal Power - % of 1775 MWt																						
			0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	88	91	94	97	100
Reactor Coolant System (RCS) Flow Measurement	Elbow Tap ΔP and/or Calorimetric	X																		X					X
Incore-Excore Axial Offset Calibrations	Calibrate Excore Instrumentation to Incore Axial Offset																			X[1]					
Load Changes	10% Ramp to Verify System Response								X																X
Turbine Trip	OST Turbine to Verify System Response						X																		

[1] Incore flux map for data acquisition will be performed at 85% of 1775 MWt and channel calibrations will be completed prior to exceeding 90% of 1775 MWt in accordance with Ginna Technical Specification SR 3.3.1.6.

Table 1
Ginna Extended Power Uprate Power Ascension Test Plan

Test / Modification	Test Description	Prior To Start *up*	Rated Thermal Power - % of 1775 MWt																						
			0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	88	91	94	97	100
Turbine Stop Valve, Governor Valve, and Intercept Valve Testing.	Standard turbine valve tests w/post-modification tests												X												
Steam Generator Level Feedwater Flow Dynamic Testing	Manually inserted level setpoint step-changes in the steam generator.								X																X
Vibration Monitoring	Monitor vibration in Plant Piping and Rotating Equipment																			X	X	X	X	X	X
Plant Radiation Surveys	Verify Expected Dose Rates																			X					X
Plant Temperature Surveys	Verify Expected Temperatures																			X					X

Table 2 Large Plant Transient Tests in Ginna EPU Power Ascension Test Plan		
Proposed Test	**Description**	**Expectation**
Turbine Overspeed Trip from 20% EPU Power	The turbine will be taken to approximately 30% power, ramped back to no-load, with the reactor at approximately 20% power, and automatically tripped as speed exceeds the mechanical overspeed trip setpoint unloaded.	This test will verify proper operation of the overspeed mechanism for the new HP turbine, proper operation of the new turbine control valves and exercise the steam dump system.
10% Load Change at new 30% and 100% EPU Power	Fast power ramps limited by station license conditions and fuel pre-conditioning considerations.	These ramps will test NSSS and BOP control system operation, to ensure that no unanticipated aggregate effects have been produced by interaction of the plant modifications.
30% Manual Turbine Trip Test	The main turbine will be manually tripped at 30% power	The reactor control systems (rod control, pressurizer level and pressure control and condenser dump valves) will operate properly to prevent a reactor trip or lifting of a pressurizer or main steam safety valve.
Turbine Stop Valve, Governor Valve, and Intercept Valve Testing at 50% EPU Power	Standard turbine valve testing augmented by post-modification tests associated with HP Turbine and Governor Valve Replacement.	Validate dynamic performance of new governor valve design to ensure adequate transient response. Verify acceptable dynamic performance of the new HP turbine rotor during changes in individual arc steam flows.
Steam Generator Level / Feedwater Flow Dynamic testing at 30% and 100% EPU Power	Manually inserted level setpoint step-changes in the steam generator. Both up-going and down-going setpoint changes of different magnitudes will be inserted.	Verify SG level control system response and acceptability of over-shoot, damping and steady-state limit cycling at the new licensed power level. Verify acceptable operation of the digital feedwater control system.

Startup Physics Testing

Introduction

At the start of Cycle 33, the physics testing program was executed to ensure core reactivity parameters and power distribution indications were in agreement with the predicted behavior and within the bounds of the safety analysis. Parameters were observed during low-power physics and power ascension testing that measured the following:

1. Reactivity worth of shutdown and control banks
2. Hot zero power boron endpoint
3. Isothermal temperature coefficient
4. Power distribution behavior

All parameters met review and acceptance criteria for low-power physics testing and all power ascension power distribution requirements were met and were in agreement with predicted behavior and are well within the bounds of the safety analysis.

Reactivity Worth of Shutdown and Control Banks

Bank worths were determined by using the Dynamic Rod Worth Measurement (DRWM) technique described in WCAP-13360-P-A. The results can be seen in Table 3. All individual banks met review criteria of the larger of ±15% of individual bank worth or ±100 pcm and total integrated rod worth also met review criteria of within ±5.6%.

Hot Zero Power Boron Endpoint

Hot zero power boron endpoint was measured during the dilution to criticality in the all rods out (ARO) configuration. Boron endpoint at the just critical condition was determined to be 2137 ppm. This measurement differed from the predicted value of 2134 ppm by 3 ppm or 18.5 pcm. This deviation is well within the review criteria of ±50 ppm or ±500 pcm.

Isothermal Temperature Coefficient

Isothermal temperature coefficient data was also obtained at the ARO condition. The average measured value was determined to be +0.85 pcm/°F. Compared to the predicted value of +0.86 pcm/°F, this measurement is well within the ±2 pcm/°F review criteria.

Power Distribution Behavior

Flux maps were performed at several plateaus during power ascension to determine power distribution characteristics, including nuclear enthalpy rise hot channel factor, heat flux hot channel factor, core tilt, and axial flux difference. Because Cycle 33 implements a transition core, separate limits were developed for the Optimized Fuel Assembly (OFA) and 422V+ fuel types. Measured values were all within technical specification limits and are listed in Table 4, Table 5, Table 6, Table 7, Table 8 and Table 9.

Table 3 Integral Bank Worth Measurement Results

BANK	MEASURED (PCM)	PREDICTED (PCM)	ERROR (PCM) M-P	ERROR (%) (M-P)/P
CA	972.5	934.6	37.9	4.1%
CB	581.6	598.0	- 16.4	-2.7%
CC	934.7	903.7	31.0	3.4%
CD	794.3	773.4	20.9	2.7%
SA	1557.3	1,434.1	123.2	8.6%
TOTAL	4,840.4	4,643.8	196.6	4.2%

Table 4 Maximum Nuclear Enthalpy Rise Hot Channel Factors for OFA Fuel

Power Level	$F^N_{\Delta H}$	$F^N_{\Delta H}$ w/ Uncertainty	Limit
29.53	1.4226	1.4795	1.938
85.69	1.3866	1.4421	1.669
94.19	1.3790	1.4342	1.628
99.98	1.3736	1.4286	1.600

Table 5 Maximum Nuclear Enthalpy Rise Hot Channel Factors for 422V+ Fuel

Power Level	$F^N_{\Delta H}$	$F^N_{\Delta H}$ w/ Uncertainty	Limit
29.53	1.6001	1.6641	2.084
85.69	1.5102	1.5706	1.794
94.19	1.5349	1.5963	1.750
99.98	1.5361	1.5975	1.720

Table 6 Maximum Heat Flux Hot Channel Factors for OFA Fuel

Power Level	$F_Q^N(Z)$	$F_Q^C(Z)$	$F_Q^W(Z)$ x 1.02	Limit
29.53	1.9277	2.0848	2.4752	5.2000
85.69	1.6585	1.7937	2.1071	3.0341
94.19	1.6990	1.8374	2.1112	2.7603
99.98	1.6953	1.8334	2.1102	2.6005

Table 7 Maximum Heat Flux Hot Channel Factors for 422V+ Fuel

Power Level	$F_Q^N(Z)$	$F_Q^C(Z)$	$F_Q^W(Z)$ x 1.02	Limit
29.53	2.1605	2.3366	2.7764	5.2000
85.69	1.8039	1.9509	2.2946	3.0341
94.19	1.8816	2.0349	2.3154	2.7603
99.98	1.8892	2.0432	2.3186	2.6005

Table 8 Maximum Core Tilt

Power Level	Incore Tilt	Limit
29.53	1.0055	N/A
85.69	1.0025	1.02
94.19	1.0054	1.02
99.98	1.0055	1.02

Table 9 Core Average Axial Flux Difference

Power Level	AFD	Limit
29.53	2.839	N/A
85.69	-1.581	-17.15<AFD<11.15
94.19	-0.730	-14.09<AFD<8.09
99.98	-0.643	-12<AFD<6

Low Power Transient Testing

Steam Generator Level Test

Reactor power was increased to approximately 30% power at 1500 on November 2, 2006. At 1515 the A steam generator level testing was commenced. The A steam generator water level setpoint was reduced from the normal setpoint of 52% to 47%. After stabilization at the 47% level the setpoint was increased to the normal setpoint of 52%. This test verified the capability of the feedwater level control system to control steam generator level in a stable fashion in response to a step change in level setpoint. The response to this setpoint change was as expected. No operator intervention to establish manual control was required. Level overshoot (or undershoot) for both setpoint changes were less than 1.2%. The A steam generator water level returned smoothly to the normal setpoint with no significant oscillations. Figure 2 shows a plot of important parameters for the A steam generator level test.

At 1550 on November 2nd the B steam generator level testing was commenced. The B steam generator water level setpoint was reduced from the normal setpoint of 52% to 47%. After stabilization at the 47% level the setpoint was increased to the normal setpoint of 52%. The response to this setpoint change was as expected. No operator intervention to establish manual control was required. Level overshoot (or undershoot) for both setpoint changes were less than 2.3%. The B steam generator water level returned smoothly to the normal setpoint with a small oscillation of 0.6% and this met acceptance criteria. Figure 3 shows a plot of important parameters for the B steam generator level test.

10% Power Ramp Test

At 1720 on November 2nd the 10% power ramp test was commenced. For this test the turbine power was ramped to reduce reactor power from 30% to 20% at 1% per minute. This test verified the capability of the control systems to maintain coolant average temperature, pressurizer level and pressurizer pressure, and steam generator level within the appropriate program bands during a transient at low power. All parameters responded as expected according to the predicted design program. As expected, rod control was taken to manual after reaching 20% reactor power in order to stabilize coolant temperature control with a positive moderator temperature coefficient. Figure 4 shows a plot of important parameters for the 10% down power ramp test at low power.

At 1748 on November 2nd the 10% power ramp test from 20% to 30% was commenced. For this test the turbine power was ramped to increase reactor power from 20% to 30% at 1% per minute. This test verified the capability of the control systems to maintain coolant average temperature, pressurizer level and pressurizer pressure, and steam generator level within the appropriate program bands during a transient at low power. All parameters responded as expected according to the predicted design program. As expected, rod control was taken to manual after reaching 30% reactor power in order to stabilize coolant temperature control with a positive moderator temperature coefficient. Figure 5 shows a plot of important parameters for the 10% up power ramp test at low power.

30% Manual Turbine Trip Test

At 1917 on November 2nd the 30% manual turbine trip test was commenced. For this test the reactor was initially at 30% power and a manual turbine trip was performed. The plant response to the load rejection was monitored to verify the appropriate control system response. Acceptance criteria for the test included no reactor trip, no pressurizer or main steam safety opening, and no pressurizer power operated relief valve opening. All acceptance criteria for the test were met. After automatic runback of reactor power to approximately 12%, manual rod control was taken as planned to maintain reactor power above 10%. Although the plant response was generally as expected, reactor coolant average temperature oscillations began to slowly diverge due to continued cycling of four steam dump valves. Steam dump control was taken to the pressure control mode to stabilize the oscillations. Although test acceptance criteria were met, a Condition Report was written to enter the issue into the station corrective action program.

Subsequently, the low power feed forward gain in the digital feedwater control system was reduced to address this issue. Figures 6 through 9 show plots of important parameters for the manual turbine trip from 30% power.

Main Turbine Overspeed Test

After the manual turbine trip the main turbine was reset and speed increased to perform the overspeed trip test with the reactor at approximately 12% power. This test verified proper operation of the overspeed mechanism for the new HP turbine. The measure speed of the trip was 107.5% as compared to a setpoint requirement of less than 109.3%.

Turbine Valve Testing at 47% Power

At 47% power the normal turbine valve stroke test was performed per site procedure T-18. During this test two turbine control valves are manually stroked shut while the remaining two turbine control valves automatically stroke open to maintain turbine load. With two turbine control valves shut, the corresponding main turbine stop valve is then stroked shut with no impact on turbine load. The test is then repeated for the opposite pair of turbine control valves and the corresponding turbine stop valve. This test was completed successfully with no turbine control issues.

Plateau Testing from 85% to 100% Power

Critical Parameter Monitoring During Power Ascension

As part of the Ginna Extended Power Uprate (EPU) Power Ascension Test Program, approximately ninety-five (95) parameters related to the Reactor Coolant System (RCS) and the Balance of Plant (BOP) power conversion systems were selected to be monitored during power ascension from ~85.6% power to 100% power. Twenty-two (22) parameters relating to the RCS were monitored during the power ascension. The remaining points that were monitored primarily related to BOP thermal hydraulic parameters. The power ascension was performed in ~3% increments over a ten day period. At the end of each 3% power increase, the plant was allowed to come into equilibrium before data gathering was performed of the plant parameters. Data gathering was primarily performed with the plant computer; however, for certain parameters which are not monitored by the plant computer, local test instruments were used to obtain plant data at each plateau.

At each power level plateau above 85% power, the values of the RCS and BOP parameters being monitored were obtained. Depending upon the plant parameter, the measured values were then compared to either an expected range for the specific parameter at the specific power level or to a parameter operational limit that had to be satisfied. Operational limits typically were independent of power level. Examples of parameters that were compared to operational limits were Main Feedwater (MFW) Pump and Motor bearing temperatures, RCS Over-Power and Over-Temperature differential temperature limits and Main Transformer winding and oil temperatures. At each plateau any parameter whose actual value either did not fall within its expected range or exceeded an operational limit was evaluated for acceptability prior to continuing the power ascension. A summary of the parameters that were monitored and the measured results obtained at each power ascension plateau is provided in Table 10.

Table 10 - Summary of Plant Parameters Monitored during Power Ascension

#	Parameter	Units	Point /	Actual Plant Values							
	Core Power (%)	%	Instrument	79.2%	83.3%	85.6%	87.8%	90.6%	94.20%	96.74%	100.0%
	CorePower (MWt)	MWt		1405.8	1478	1520	1558	1609	1672	1717	1775
A	**PRIMARY**										
1	Core Power	%	CALMWTPC	79.2	83.27	85.64	87.78	90.64	94.20	96.74	99.85
2	Nuclear Power	%	NP	79.20	83.27	85.64	87.47	90.60	93.96	96.55	99.94
3	RCSTavg	F	TAVG	568.74	569.9	570.37	571.27	571.90	573.34	573.56	573.75
4	RCS Loop DT	F	DT	52.18	54.73	56.92	58.25	60.30	62.38	63.93	65.82
5	Pressurizer Pressure	psig	PPZR	2232.6	2232.4	2232.6	2232.6	2232.0	2232.6	2232.6	2232.6
6	Pressurizer Level	%	LPZR	49.54	51.15	51.76	53.43	53.82	55.61	55.92	56.14
7	T-Ref (Tavg Regference)	F	TREF	568.15	569.41	570.55	571.19	572.00	573.16	573.66	573.59
8	Average Tavg - TREF Deviation	F	TDEVI	0.6	0.49	-0.18	0.07	-0.10	0.18	-0.10	0.16
	LOOP A										
9	Loop Tavg	F	TAVGRCLA	567.9	569.00	569.48	570.07	571.83	573.31	573.53	573.70
10	Loop DT	F	TDTRCLA	52.13	54.42	56.56	57.67	61.01	62.93	64.48	66.33
11	Loop Flow	%	FRCLA	101.46	101.44	101.43	101.47	101.05	101.26	101.28	101.32
12	Channel 1 OTDT Margin to Runback	F	T0405ARB	32.18	28.56	25.82	23.94	18.48	14.55	12.66	10.62
13	Channel 2 OTDT Margin to Runback	F	T0406ARB	33.16	29.60	26.88	25.10	19.78	16.05	14.30	12.27
14	Channel 1 OPDT Margin to Runback	F	T0405CRB	17.72	15.40	13.25	12.10	9.10	6.76	5.16	3.31
15	Channel 2 OPDT Margin to Runback	F	T0406CRB	19.02	16.79	14.73	13.70	9.12	6.63	5.14	3.30
	LOOP B										
16	Loop Tavg		TAVGRCLB	569.41	570.61	571.08	571.67	571.88	573.17	573.39	573.61
17	Loop DT		TDTRCLB	53.62	56.01	58.28	60.11	60.91	62.90	64.45	66.41
18	Loop Flow		FRCLB	99.79	99.76	99.78	99.70	99.55	99.65	99.66	99.73
19	Channel 3 OTDT Margin to Runback	F	T0407ARB	30.41	26.55	23.72	20.33	19.46	15.99	14.18	11.97
20	Channel 4 OTDT Margin to Runback	F	T0408ARB	28.46	24.70	21.83	20.01	18.96	15.20	13.42	11.18
21	Channel 3 OPDT Margin to Runback	F	T0407CRB	17.51	15.12	12.86	11.59	9.78	7.46	5.95	4.00
22	Channel 4 OPDT Margin to Runback	F	T0408CRB	16.15	13.75	11.46	10.18	9.33	7.13	5.58	3.61

Table 10 - Summary of Plant Parameters Monitored during Power Ascension

#	Parameter	Units	Point /	Actual Plant Values							
	Core Power (%)	%	Instrument	79.2%	83.3%	85.6%	87.8%	90.6%	94.20%	96.74%	100.0%
	CorePower (MWt)	MWt		1405.8	1478	1520	1558	1609	1672	1717	1775
B	**SECONDARY**										
	Steam Generator A										
23	Main Steam Pressure	psig	PSGA	824.46	817.26	807.08	806.51	806.71	803.82	795.05	783.40
24	Main Feedwater Flow	klb/hr	FFWAQ	2965.9	3127.50	3277.11	3354.00	3473.64	3625.64	3729.40	3858.49
25	Main Steam Flow	klb/hr	FSTMAQ	2729.6	2895.40	3052.53	3132.80	3259.73	3393.48	3512.90	3664.41
26	SG Narrow Range Level	%	LSGAQ	51.73	51.93	51.92	51.98	51.95	52.01	53.03	51.92
27	SG Inlet Temperature	F	T2096	411.3	415.13	418.70	420.36	422.77	425.91	427.83	430.19
28	MFW A Reg Valve	%	V4269	40.27	43.57	43.14	45.11	49.15	56.18	61.34	68.04
29	SG Blowdown Flow	gpm	F4100	86.16	85.60	83.50	83.43	87.33	95.46	92.34	94.18
	Steam Generator B										
30	Main Steam Pressure	psig	PSGB	829.75	822.91	811.93	806.45	808.82	806.40	797.39	785.05
31	Main Feedwater Flow	klb/hr	FFWBQ	2963.2	3123.50	3277.41	3367.20	3488.30	3642.80	3749.00	3881.43
32	Main Steam Flow	klb/hr	FSTMBQ	2650.6	2808.60	2970.87	3083.50	3178.91	3326.46	3444.70	3595.29
33	SG Narrow Range Level	%	LSGBQ	51.61	52.06	52.10	51.95	51.72	51.79	51.60	51.92
34	SG Inlet Temperature	F	T2097	411.76	415.52	419.07	420.73	423.14	426.28	428.20	430.56
35	MFW A Reg Valve	%	V4270	40.84	44.27	43.83	46.07	50.68	59.11	65.75	75.00
36	SG Blowdown Flow	gpm	F4101	86.71	86.30	85.32	83.04	83.26	92.84	91.42	95.00
C	**Main Feedwater Pumps**										
	MFW Pump A										
37	MFWP A Suction Pressure	psig	P2044	298.1	288.55	283.46	276.81	268.13	247.92	237.59	231.71
38	MFWP A NPSH Margin	ft	NPMRMFPA	397	356.26	340.62	318.41	285.48	208.42	169.22	134.97
39	MFWP A Discharge Pressure	psig	P2046	1152.7	1124.33	1149.87	1132.50	1106.52	1070.23	1044.40	1027.22
	MFWP A Temperatures										
40	Pump Thrust Bearing	F	T2071	103.17	103.48	103.42	104.36	104.49	105.34	105.80	105.62
41	Pump Inboard Bearing	F	T2072	102.57	102.87	102.76	103.43	103.26	102.22	102.57	102.76
42	Pump Outboard Bearing	F	T2073	129.32	129.61	129.37	129.68	129.84	130.13	130.52	130.65
43	Speed Increaser - Motor High	F	T2074	148.36	148.59	148.48	148.36	149.51	148.98	150.27	150.16
44	Speed Increaser - Motor Low	F	T2075	144.25	144.15	144.36	143.17	142.93	141.07	142.07	141.68
45	Speed Increaser - Pump High	F	T2076	150.74	150.79	150.43	150.27	150.31	150.54	151.60	152.03
46	Speed Increaser - Pump Low	F	T2077	142.29	142.42	142.46	142.48	142.61	142.23	143.02	143.20

Table 10 - Summary of Plant Parameters Monitored during Power Ascension

#	Parameter	Units	Point /	Actual Plant Values							
	Core Power (%)	%	Instrument	79.2%	83.3%	85.6%	87.8%	90.6%	94.20%	96.74%	100.0%
	Core Power (MWt)	MWt		1405.8	1478	1520	1558	1609	1672	1717	1775
	MFW Pump B										
47	MFWP B Suction Pressure	psig	P2045	297.6	287.94	279.23	272.50	263.87	243.91	234.03	228.36
48	MFWP B NPSH Margin	ft	NPMRMFPB	392.7	349.98	283.51	257.75	221.86	144.46	106.06	72.52
49	MFWP B Discharge Pressure	psig	P2047	1147.9	1119.52	1149.14	1130.95	1107.25	1073.02	1043.30	1021.67
	MFWP B Temperatures										
50	Pump Thrust Bearing	F	T2082	102.61	102.48	100.44	101.03	100.87	100.71	100.93	101.04
51	Pump Inboard Bearing	F	T2083	106.73	106.89	106.93	106.37	106.37	106.43	107.57	107.74
52	Pump Outboard Bearing	F	T2084	85.55	85.73	85.69	87.05	86.90	85.89	86.80	86.84
53	Speed Increaser - Motor High	F	T2085	154.84	155.07	156.29	156.57	156.57	156.31	157.39	157.62
54	Speed Increaser - Motor Low	F	T2086	143.15	143.28	144.00	144.16	144.14	143.66	144.93	145.13
55	Speed Increaser - Pump High	F	T2087	151.95	152.03	153.82	154.10	154.30	154.11	155.06	155.61
56	Speed Increaser - Pump Low	F	T2088	157.48	157.16	156.00	156.10	156.02	155.93	156.30	156.42
D	**Condensate Pumps**										
57	CP Discharge Header Pressure	psig	P2043	275.5	279.91	276.78	287.89	292.16	282.13	274.88	270.82
E	**HP Turbine**										
58	HPT Inlet Pressure	psig	Local	794.5	790.50	778.50	768.50	769.00	760.00	747.00	732.50
59	1st Stage pressure	psig	P1STAGE	490.66	519.34	545.40	558.48	579.03	604.15	626.95	638.51
60	Ext Pressure to #5 FW Htrs	psig	Local	283.5	296.00	310.00	318.00	330.00	344.00	352.00	365.50
61	HP Turbine Exhaust Pressure	psig	Local	119.5	125.00	131.00	135.00	141.00	146.50	152.00	155.25
F	**Moisture Seperator/Reheaters**										
62	MSR1A Steam Flow	klb/hr	F6660	134.46	133.46	137.81	138.51	146.01	143.54	142.99	143.60
63	MSR1B Steam Flow	klb/hr	F6660	133.91	135.64	138.85	138.51	141.06	143.54	142.99	142.66
64	MSR2A Steam Flow	klb/hr	F6661	124.75	127.26	128.59	130.01	131.65	133.40	132.52	132.88
65	MSR2B Steam Flow	klb/hr	F6661	122.36	125.52	126.89	127.23	128.91	130.20	131.47	131.34
66	MSR Avg Outlet Pressure	psig	Local	113.1	119.40	125.40	128.40	133.50	139.50	143.40	148.50

Table 10 - Summary of Plant Parameters Monitored during Power Ascension

#	Parameter	Units	Point /	Actual Plant Values							
	Core Power (%)	%	Instrument	79.2%	83.3%	85.6%	87.8%	90.6%	94.20%	96.74%	100.0%
	Core Power (MWt)	MWt		1405.8	1478	1520	1558	1609	1672	1717	1775
G	**LP Turbine**										
67	LPA Steam Inlet Temp.	F	T2125	506.73	505.14	502.91	502.08	501.69	500.46	498.75	496.53
68	LPB Steam Inlet Temp.	F	T2126	504.89	503.40	501.32	500.57	500.30	499.26	497.67	495.52
H	**Condensate Booster Pumps**										
69	CBP Discharge Pressure	psig	P4017	389.1	388.98	389.23	389.41	386.92	373.39	370.38	371.17
70	CBP A Suction Pressure	psig	PI-2525	255	250.00	260.00	260.00	265.00	245.00	250.00	250.00
71	CBP B Suction Pressure	psig	PI-2529	255	260.00	260.00	260.00	257.00	245.00	255.00	250.00
72	CBP C Suction Prressure	psig	PI-2533	255	255.00	255.00	255.00	255.00	250.00	255.00	247.00
I	**Heater Drain System**										
73	Heater Drain Flow	klb/hr	F2003	1624	1724.61	1842.74	1894.50	1968.72	2120.58	2167.90	2203.40
74	Heater Drain Tank Pressure	psig	P2021	109.43	114.74	120.01	121.53	124.63	131.73	135.02	140.32
J	**Condenser**										
	Condenser A										
75	Condenser A Pressure	in Hg	PBACKA	1.15	1.21	1.25	1.34	1.39	1.45	1.48	1.79
76	Condenser A Inlet Temperature	F	T2031	49	49.28	48.77	50.32	49.92	50.56	49.86	50.19
77	Condenser A Outlet Temperature	F	T2033/T2034	67.84	69.09	69.33	71.25	71.48	72.91	72.74	74.29
78	Condenser A DT	F	Calc	18.84	19.81	20.56	20.93	21.56	22.35	22.88	24.10
	Condenser B										
79	Condenser B Pressure	in Hg	PBACKB	1.17	1.23	1.27	1.37	1.39	1.48	1.50	1.56
80	Condenser B Inlet Temperature	F	T2032	49.04	49.29	48.80	50.34	49.94	50.58	49.87	50.20
81	Condenser B Outlet Temperature	F	T2035/T2036	68.65	69.74	70.05	72.01	72.26	73.88	73.72	74.66
82	Condenser B DT	F	Calc	19.61	20.45	21.25	21.67	22.32	23.30	23.85	24.46
K	**Electrical**										
83	Generator MVA	MVA		469	493	516.00	530.00	549	570	587	606.00
84	Generator Gross Generation	MWe	GROSS	468.04	492.40	515.05	529.08	548.40	570.04	586.21	605.17
85	Generator Cold Gas Temperature	C		39	39.00	39.00	40.00	40.00	41.00	41.00	41.00
86	GSU Top Oil Temperature	C	GSUT01	34.94	37.37	41.02	47.81	54.39	54.33	55.39	55.82
87	GSU Winding Temperature	C	GSUT02	43.14	46.20	50.71	57.97	65.36	65.60	67.12	68.18

Table 10 - Summary of Plant Parameters Monitored during Power Ascension

#	Parameter	Units	Point /	Actual Plant Values							
	Core Power (%)	%	Instrument	79.2%	83.3%	85.6%	87.8%	90.6%	94.20%	96.74%	100.0%
	Core Power (MWt)	MWt		1405.8	1478	1520	1558	1609	1672	1717	1775
L	**Containment Temperature**										
88	Containment Intermediate Level - # 7	F	TCV07	93.93	93.86	93.90	94.43	94.60	93.34	92.61	92.18
89	Containment Intermediate Level - # 8	F	TCV08	97.18	97.31	97.24	97.99	98.13	95.35	94.67	94.16
90	Containment Intermediate Level - # 9	F	TCV09	93.51	93.61	93.54	94.40	94.34	94.63	93.93	93.57
91	Containment Operating Level	F	TCV17	98.94	98.93	98.97	99.66	99.87	100.93	100.14	99.66
92	Containment Average	F	Average	95.89	95.93	95.91	96.62	96.74	96.06	95.34	94.89
93	Lake Temperature	F	T3001	46.82	47.07	46.58	48.09	47.69	48.35	47.63	47.94
M	**HP Turbine Control Valves**										
94	Control Valve 1 Position	%	Control Room			37	37	38	41	44	53
95	Control Valve 2 Position	%	Control Room			35	36	38	40	42	51
96	Control Valve 3 Position	%	Control Room			34	36	38	40	42	51
97	Control Valve 4 Position	%	Control Room			35	37	38	40	44	52

Issues Identified During Ascension to 100%

In general during power ascension testing most of the monitored RCS and BOP plant parameters satisfied the specified acceptance criteria. A small number of parameters were identified to be outside the expected range at 88% and again at 91%. However, the difference between the expected value and the acceptance range was small for all of the parameters. And at the higher plateaus all of the parameters came within the expected range with the exception of pressurizer level. Pressurizer level was consistently greater than 1% above the expected value up through 97% power; however, at 100% power the measured pressurizer level was within 0.1% of the expected value. The difference in expected pressurizer level versus actual level was due to a higher RCS reference average coolant temperature (Tref) value than expected. The higher Tref was based on a high HP Turbine first stage pressure reading as discussed below.

During the power ascension although the average High Pressure (HP) Turbine first stage pressure reading met the specified acceptance criteria, the difference in indicated pressures between the two HP Turbine first stage pressure transmitters was larger than expected based on past plant operation. Consequently, at the 97% power plateau a check of the pressure transmitter outputs was performed which determined that one of the two transmitters (PT-485) was reading high by ~20 psi. This transmitter was recalibrated at 97% prior to performing the final power ascension to 100% power. Since PT-485 is used to define Tref for the RCS pressurizer level control, its higher reading up through 97% power caused actual pressurizer level to be slightly higher than expected during the power ascension. Due to the re-calibration of the pressure transmitter at 97% power which decreased its reading by ~20 psi, the actual pressurizer level reading at 100% agreed closely with the expected pressurizer level.

The major BOP issues that arose during the power ascension to 100% were:

- Reduced Main Feedwater (MFW) Pump B net positive suction head (NPSH) margin at power levels above 94% power
- Increased magnitude of oscillation of the two MFW Regulating Valves above 91% power

The reduced MFW Pump B NSPH margin as compared to the expected margin was due to a flow imbalance that occurred between the two MFW Pumps at 85% power. This imbalance is attributed to a hump in the MFW Pump curves for the new MFW Pump impellers that was discovered during factory testing of the new impellers. This flow imbalance remained in effect throughout the remainder of the power ascension to 100%. This imbalance caused MFW Pump B to operate approximately 8% higher than expected with a corresponding decrease in MFW Pump A flow at full power. The increase in actual MFW Pump B flow resulted in an increase in the required NPSH for this pump and a corresponding decrease in its available margin. Although the measured MFW Pump NPSH margin was less than expected, the margin still exceeded the low NPSH margin alarm for the MFW Pumps. To address this issue during power ascension, the operating differential pressure across the condensate demineralizers was reduced which increased the pressure at both MFW Pump suctions and thereby increased the available NPSH margin for both pumps. Long term corrective actions to the MFW Pump impeller design are being pursued to eliminate the existing MFW Pump flow imbalance at full power.

After reaching the 91% power level, oscillation in the two MFW Regulating Valves was observed. The oscillation in the MFW Regulating Valves resulted in unacceptable steam generator narrow range level oscillations as well as MFW Pump NPSH margin and condensate system pressure oscillations at power levels between 91% and 94%. To address this issue, tuning of the Advanced Digital Feedwater Control System (ADFCS) was performed over a five day period to optimize its operation and eliminate the unacceptable MFW Regulating Valve oscillations.

Tuning of the Advanced Digital Feedwater Control System
The new EPU plant conditions and operational parameters had significant impact on the Advanced Digital Feedwater Control System (ADFCS) ranges, limits, tuning constants, and characteristic curves. Post start-up testing was planned in addition to pre-start up testing and calibration and the potential need for ADFCS tuning based on the new plant conditions was expected. Start-up of the plant proceeded smoothly until the 91% power level plateau was reached. At that point there were excessive feedwater control system oscillations. After troubleshooting at 91% it was determined that a primary contributor to system stability was the fluctuations being seen in feedwater header pressure. An attempt was made to tune ADFCS to address the instability; however, other plant conditions affected this effort:

- Heater Drain tank level oscillations,
- MSR drain and Re-heater control,
- Pre-separator level dumping,
- Reduced Main Feedwater pump discharge operating characteristics

Once the secondary plant was stabilized it was possible to fine tune ADFCS and ascend to 100% power. The plant reached 100% power on 11/13/2006. Optimum tuning was completed on 11/29/2006 which restored some of the transient response capability without impacting the normal level control. Final EPU load ramp testing finished on 12/3/2006.

Other Monitoring Activities
In addition to monitoring critical RCS and BOP parameters during the power ascension, the following other monitoring activities were performed at each power ascension plateau to verify acceptable component operation:

- Operation of normally open BOP control valves (feedwater heaters, reheaters, pre-separator drain tanks and heater drain tank)
- Verification that BOP dump valves were closed
- Verification of proper water levels in feedwater heaters, reheaters and heater drain tank
- Monitoring of turbine vibration and bearing temperatures
- Monitoring of motor electrical and temperature data for major BOP pumps
- Thermography of main transformer, switchyard and high voltage cable components
- Monitoring of main electrical generator temperatures and vibration data

As part of the control valve and level monitoring program, tuning of the BOP control valves to optimize valve performance for stable control valve operation, acceptable feedwater heater and reheater level control and no dump valve operation was performed at various plateaus during the power ascension process. Except for periodic operation of the two pre-separator drain tank dump valves at full power, all of the BOP control valves have been operating properly at full power. The cause of the operation of the pre-separator dump valves is still under investigation and being tracked by the corrective action program.

The motor monitoring identified that the motor for MFW Pump B was operating slightly above the motor rating at 100% power. However, the motor was still operating well below its 115% service factor rating. The increase in MFW Pump B Motor load is due to the flow imbalance observed between the two MFW Pumps. No other major equipment anomalies were identified during the power ascension to the new Ginna full power rating.

Vibration Monitoring

As part of the Ginna Power Ascension Vibration Monitoring Program, piping systems directly or indirectly affected by increases in flow rates, were selected for monitoring. These systems were:

Main Steam
Feedwater
Condensate
Extraction Steam
Heater Drains
Moisture Separator Drains
Turbine Gland Steam and Drains

Pre-baseline and baseline walkdowns of these systems were performed at the pre-EPU full power level to visually identify critical areas that were potentially more susceptible to increased vibration levels due to increases in their flow rates. Twenty seven (27) points of interest were identified. Proactive analyses for the ten most critical piping segments were performed to determine maximum displacements yielding pipe stress values within the permitted piping code endurance limit.

The power ascension was performed in increments of ~3%, starting approximately at 85% power (equivalent of the old 100% power). At power levels up to 91% power, all piping monitored for vibration was observed to have displacements less than 0.125", except for seven locations where higher displacements were identified during pre-EPU baseline walkdowns. These seven locations were evaluated and deemed to have peak to peak displacements within acceptable limits.

At the 94%, 97% and 100% power plateaus, in addition to the seven locations previously identified, the "B" pre-separator tank and associated drain piping were observed to have increased vibration levels. Although stresses resulting from these conditions were within acceptable limits, modifications to the pre-separator and associated drain piping support system were designed and implemented. These modifications lowered the observed vibration levels considerably and achieved displacements of less than 0.125". No other areas of increase pipe vibration (as a result of power ascension) requiring modifications were identified during the power ascension to the new full power operating level.

Full Power Radiation Surveys

Radiation surveys were performed at each plateau during the ascension up to and including the 100% power plateau. In general, survey results were consistent with expectations regarding a proportional increase in dose rates affected by the fission process. Table 11 documents surveys performed consistent with UFSAR Tables 12.4-1 and 12.4-2. No increase in dose rates above the current values in UFSAR Tables 12.4-1 and 12.4-2 can be attributed to the power uprate.

Full Power Transient Testing

10% Power Ramp Test from 100% to 90%

At 1000 on December 2nd the 10% power ramp test from 100% reactor power to 90% reactor power was commenced. For this test the turbine power was ramped to reduce reactor power from 100% to 90% at 1% per minute. This test verified the capability of the primary control systems to maintain coolant average temperature, pressurizer level and pressurizer pressure, and steam generator level within the appropriate program bands during a transient at full power. All parameters responded as expected according to the predicted design program. Figure 10 shows a plot of important parameters for the 10% down power ramp test at full power.

Steam Generator Level Control Test at 90% Power

Although originally planned to be conducted at 100% power, the initial power for this test was reduced to 90% reactor power. The reason for reducing the initial power for the test was to provide additional operating margin for the main feedwater pump net positive suction head (NPSH). The change in the test plan was verbally communicated with the NRC. As discussed above, given the operating condition of the main feedwater pumps, there was limited margin to the required NPSH while operating at full power. During the steam generator level test, when the level setpoint is increased from 47% to 52% the feedwater regulating valves both open rapidly and call for additional feedwater flow. This portion of the transient would challenge the available NPSH. Performing the steam generator level control test at 90% power still provides assurance that the digital feedwater level control system will respond to full power transients in an acceptable fashion. For the test, both the A and the B steam generator level setpoints were reduced from 52% to 47% and, after stabilization, returned to the normal setpoint of 52%. No operator intervention to take manual control of the feedwater level control system was required. Level overshoot and undershoot during the test remained less than 3% for the test. Steam generator level was returned to the normal setpoint of 52% smoothly and within the allowed oscillation tolerances. Figures 11 and 12 show plots of the important parameters for the full power steam generator water level control test.

10% Power Ramp Test from 89% to 99%

At 1102 on December 2 the 10% power ramp test from 89% reactor power to 99% reactor power was commenced. For this test the turbine power was ramped to increase reactor power from 89% to 99% at 1% per minute. The maximum power for this ramp test was established at 99% reactor power to assure power did not exceed 100% during the test. This test verified the capability of the primary control systems to maintain coolant average temperature, pressurizer level and pressurizer pressure, and steam generator level within the appropriate program bands during a transient at full power. All parameters responded as expected according to the predicted design program. Figure 13 shows a plot of important parameters for the 10% up power ramp test at full power.

GINNA POWER UPRATE VERIFICATION SURVEYS AT 100% POWER

TABLE 11

Location to be surveyed	**UFSAR Value (mR/hr)**	**Results of Survey (mR/hr)** * = contact dose rate D = delta point survey
Auxiliary Building Intermediate RWST Area	0.5 to 4	D16 0.6; D17<0.5
Auxiliary Building Intermediate Vent Filter Area	1	<0.5
Auxiliary Building Intermediate Waste Line Southeast End	70	1.7
Auxiliary Building Intermediate Gas Compressor Room	1 to 60	D15 <0.5
Auxiliary Building Intermediate Gas Decay Tank Room	1	D19 <0.5
Auxiliary Building Intermediate Chemical and Volume Control System Tank Rooms	1 to 6	D12 0.6; D13 0.7; D14 3.2
Auxiliary Building Intermediate Volume Control Tank Room	1000 to 5000	Not Surveyed-ALARA
Auxiliary Building Intermediate Concentrates Tank Room	2 to 200 (on Filter)	*37
Auxiliary Building Intermediate Demineralizer Vault	10e3 to 10e6	Not Surveyed-ALARA
Auxiliary Building Intermediate Reactor Coolant Filter Room	50 to 20,000 (on Filter)	Not Surveyed-ALARA
Auxiliary Building Basement General Area	1 to 5	<.5 - 15
Auxiliary Building Basement RWST Room	6 to 25	D32 11; D33 20
Auxiliary Building Basement RWST Room Seal Injection Filter	1000 to 10,000	Not Surveyed-ALARA
Auxiliary Building Basement RWST Room Valves	15 to 200	25 – 220*
Auxiliary Building Basement NaOH Tank Room	4 to 160	D39 7; D40 15
Auxiliary Building Basement Non-Regenerative Heat Exchanger	15 to 250	D42 35
Auxiliary Building Basement Seal Return Cooler	4 to 35	5-10*
Auxiliary Building Basement Charging Pump Room	2 to 180	D37 2.2; D38 1
Auxiliary Building Basement Chemical and Volume Control System Tank Room	5 to 150	D26 7; D27 6; D28 10
Auxiliary Building Basement Waste Holdup Tank	15 to 2000	Not Surveyed-ALARA
Intermediate Building Elevation 253 ft	0.05 to 3	<0.5
Intermediate Building Elevation 271 to 278 ft	0.05 to 4	<0.5 - 1.8
Intermediate Building Elevation 295 to 298	0.05 to 4	<0.5
Auxiliary Building Spent Fuel Pool / Decon Pit	1	2
Auxiliary Building New Fuel Storage Area	1	<0.5
Auxiliary Building (RWST)	6	0.5

GINNA POWER UPRATE VERIFICATION SURVEYS AT 100% POWER

TABLE 11

Location to be surveyed	**UFSAR Value (mR/hr)**	**Results of Survey (mR/hr)** * = contact dose rate D = delta point survey
Auxiliary Building Monitor and Reactor Makeup Water Tank Area	1	<0.5
Auxiliary Building Waste Handling Area	5 to 10	0.6 2.3
Auxiliary Building Boric Acid Storage Tank Area	2 to 25	0.9
Auxiliary Building Drumming Station	5 to 10	2.3 West; 2.5 East
Auxiliary Building Waste Storage Vault	250 to 10,000	Not Surveyed-ALARA
Control Room	<0.05	<0.1
Ginna Service Building Offices	<0.05	<0.1
Cafeteria	<0.05	<0.1
Turbine Building General Areas	<0.05	<0.1
Turbine Building Main Steam	<0.05	<0.1
Turbine Building Reheaters	<0.05	<0.1
Turbine Building Condensers	<0.05	<0.1
Turbine Building Blowdown	<0.05	<0.1
Turbine Building Secondary Sample Sink	<0.05	<0.1
Area Radiation Monitors (mR/hr)		
R1 Control Room Area	<0.1	0.1
R2 Containment Area	10	5.3
R3 Radio Chem. Lab	0.1	0.1
R4 Charging Pump Room	5	2.2
R5 Spent Fuel Pool Area	1	0.7
R6 Nuclear Sample Room	2	0.4
R7 Incore Detector Area	10	5.5
R8 Drumming Station	3	1.1
R9 Letdown line monitor	40	2.5

GINNA POWER UPRATE VERIFICATION SURVEYS AT 100% POWER

TABLE 11

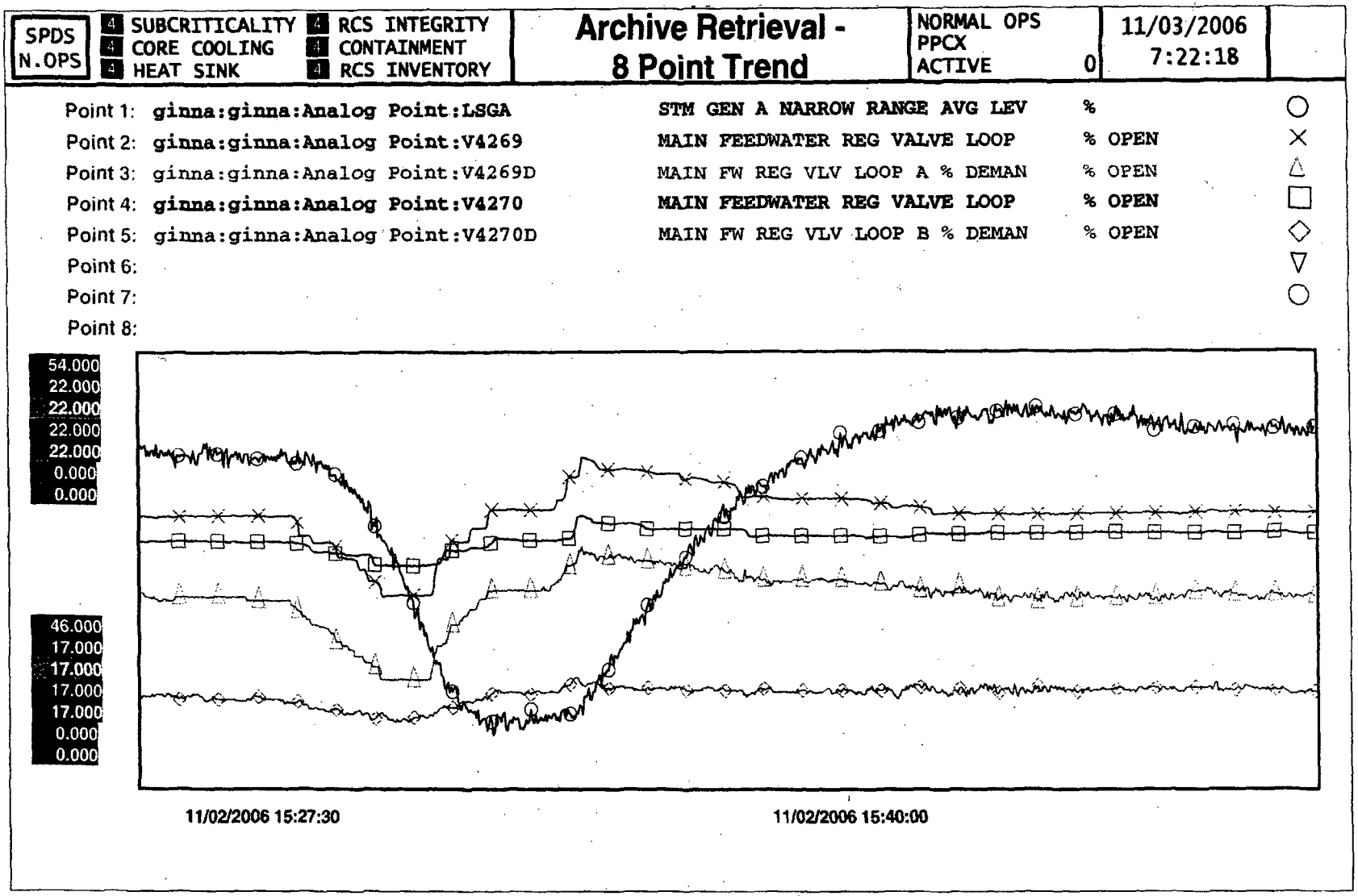
1. The Auxiliary Building Basement General Area survey range was .5 – 15 mR/hr, the UFSAR value is 1 – 5 mR/hr. This is acceptable within the assumptions made as the RHR system was previously in service and was contributing to the dose rate in that area.

2. The Auxiliary Building Basement RWST Room Valves are within the UFSAR values for general area dose rates. The survey also performed contact dose rates (Survey data value with an * = contact survey) on random valves.

3. The Auxiliary Building Spent Fuel Pool / Decon Pit survey was up to 2 mR/hr, UFSAR value is 1 mR/hr. This is acceptable within the assumptions made.

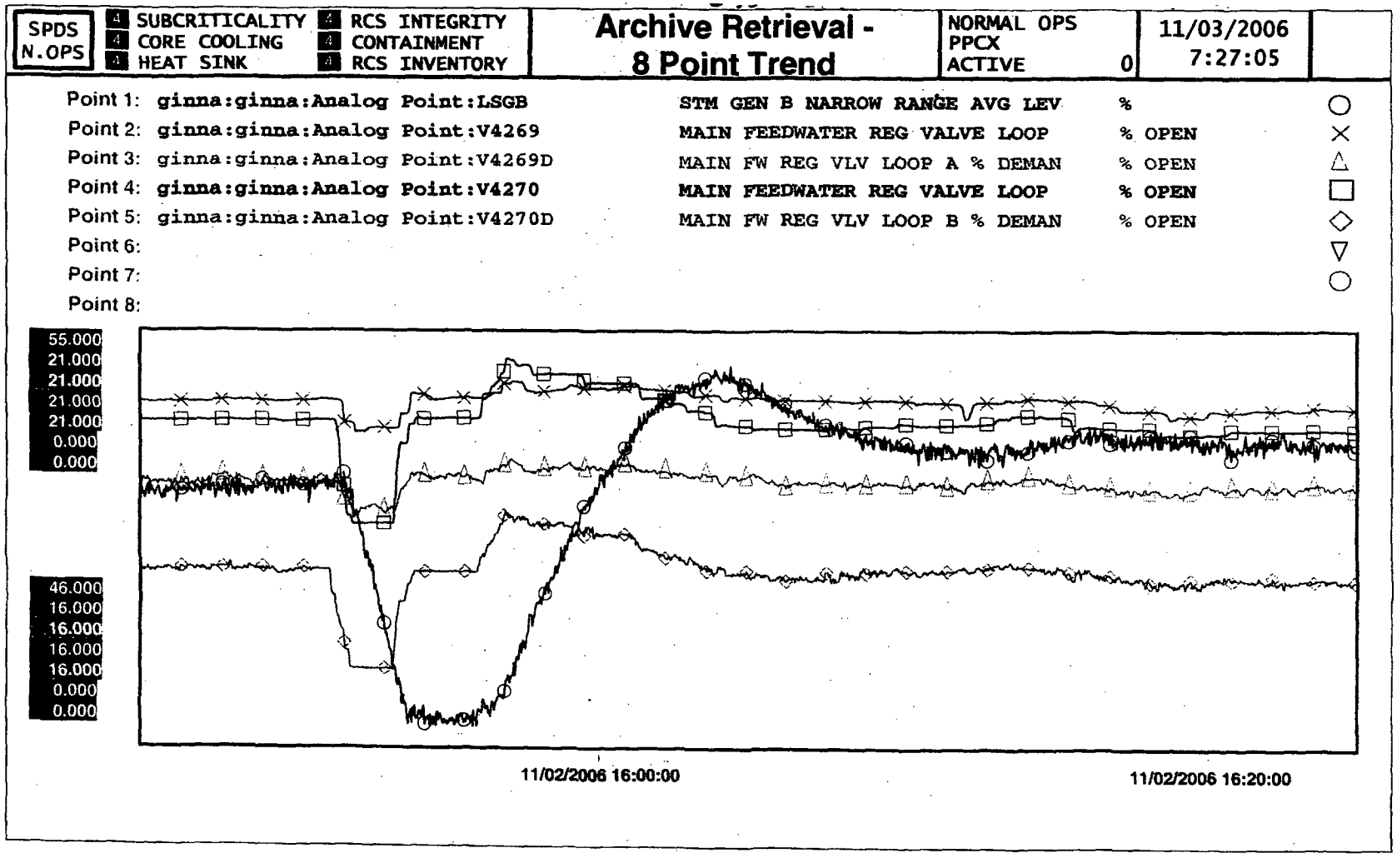
SG A 5% LEVEL CHANGE AT 30% POWER

FIGURE 2



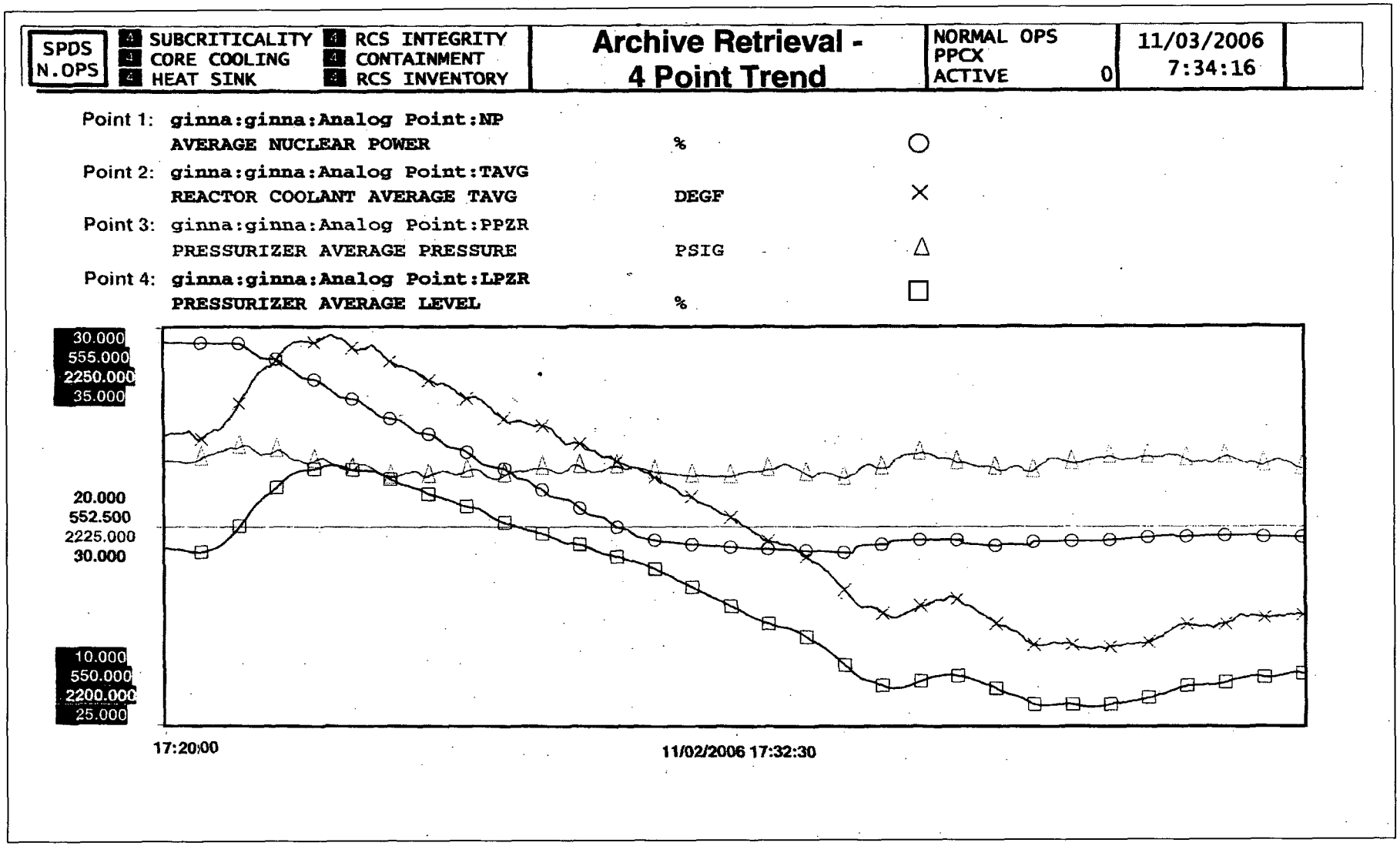
SG B 5% LEVEL CHANGE AT 30% POWER

FIGURE 3



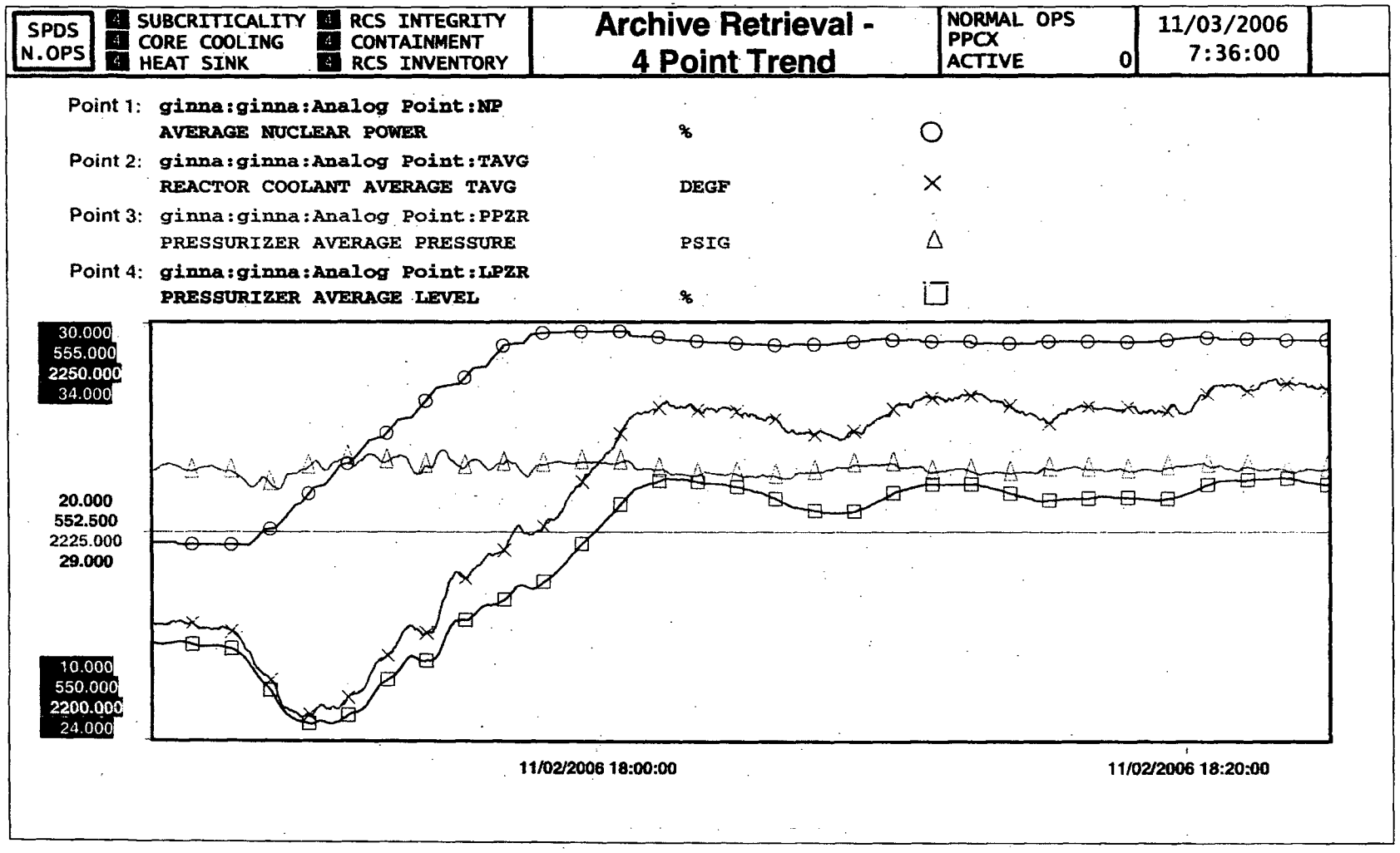
10% RAMP DOWN AT 30% POWER

FIGURE 4



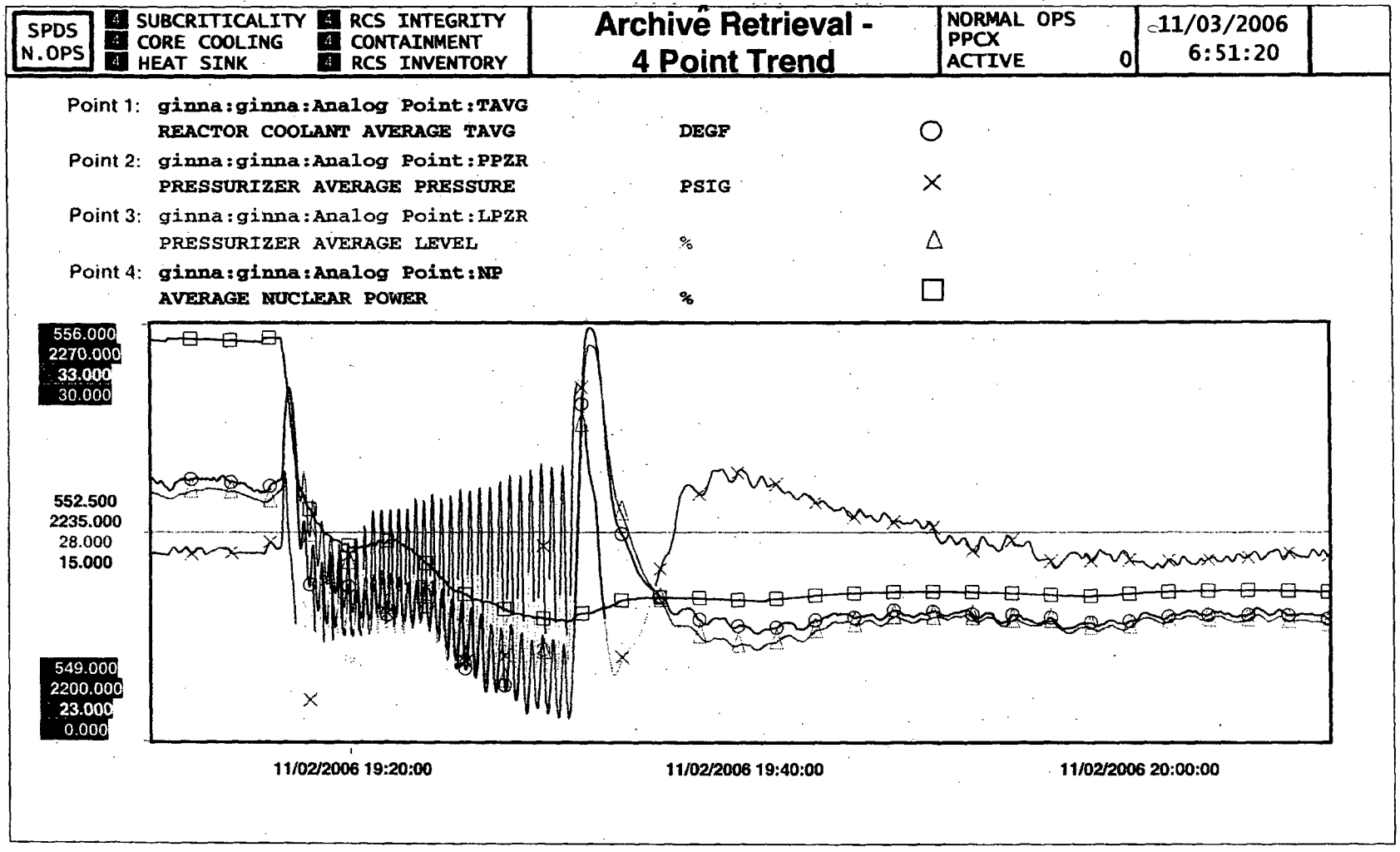
10% RAMP UP AT 20% POWER

FIGURE 5



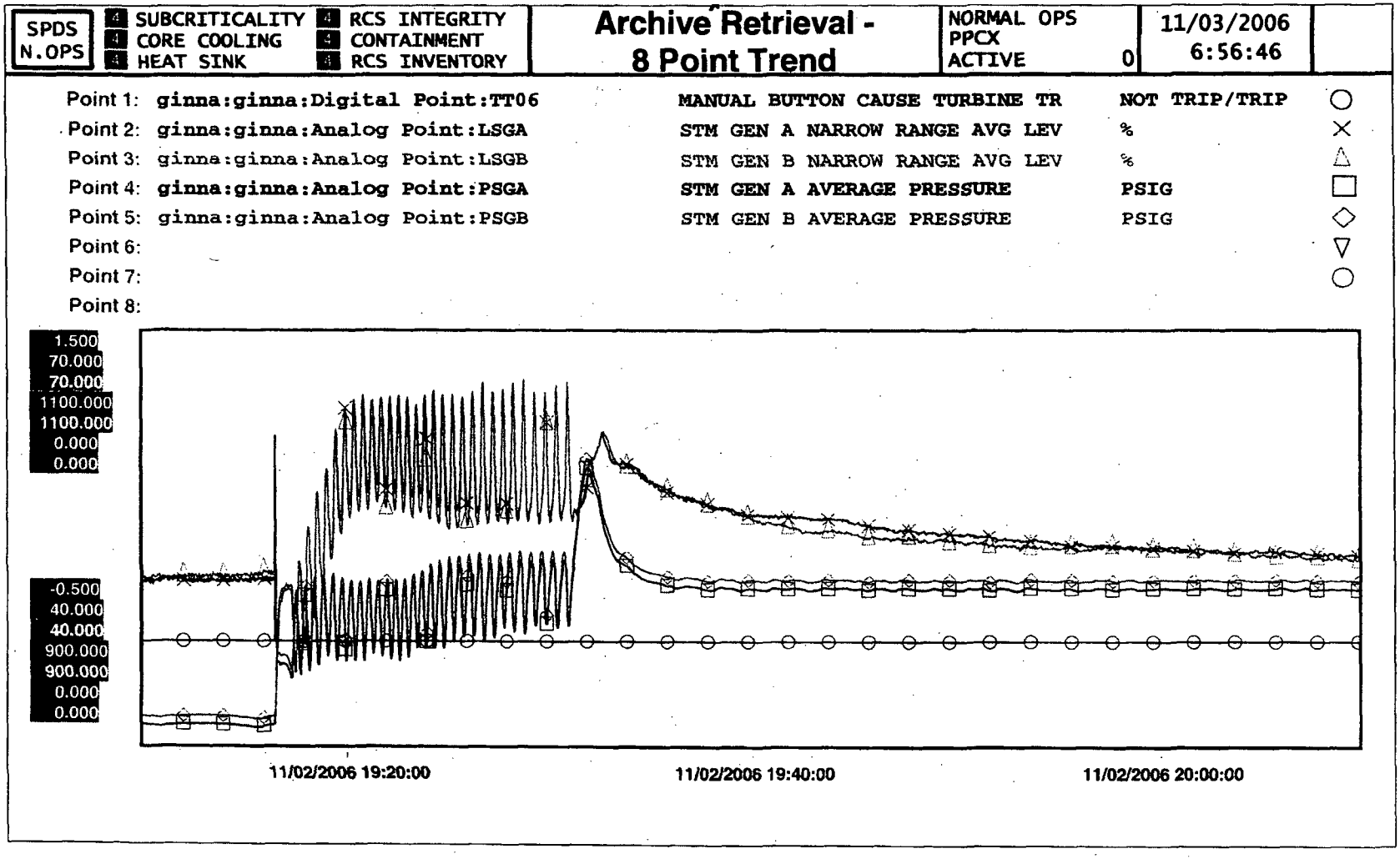
30 % MANUAL TURBINE TRIP

FIGURE 6



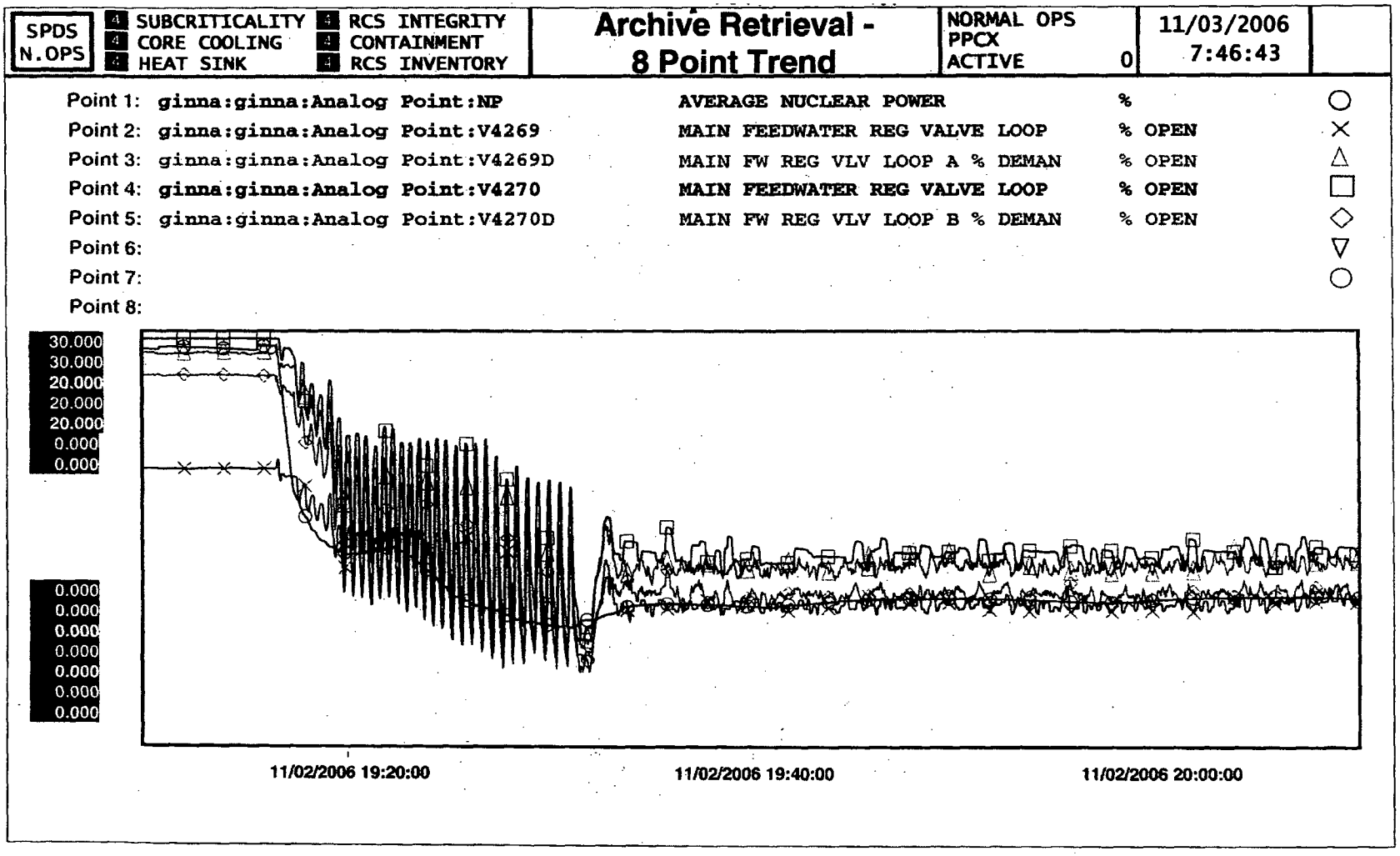
30 % MANUAL TURBINE TRIP

FIGURE 7



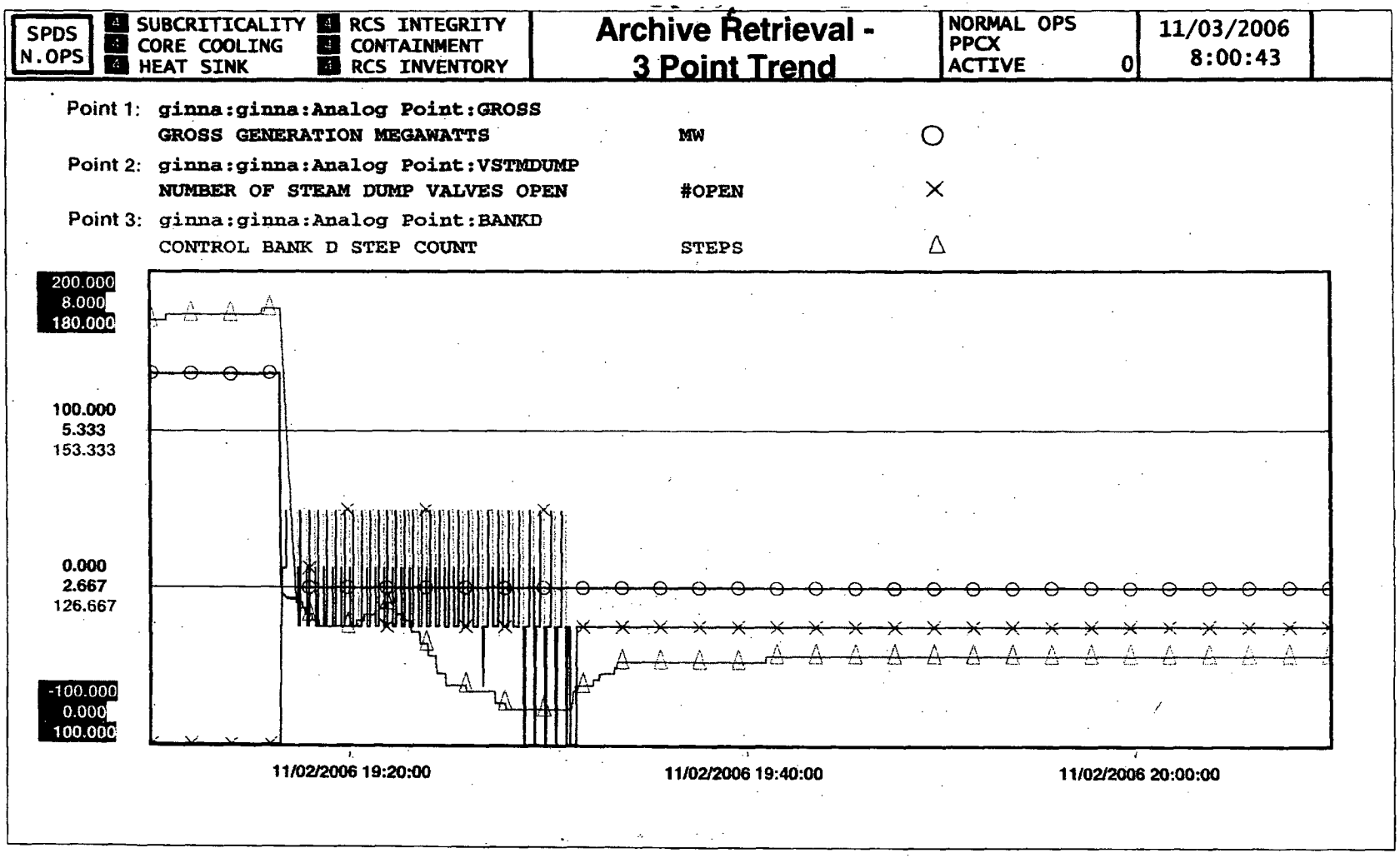
30 % MANUAL TURBINE TRIP

FIGURE 8



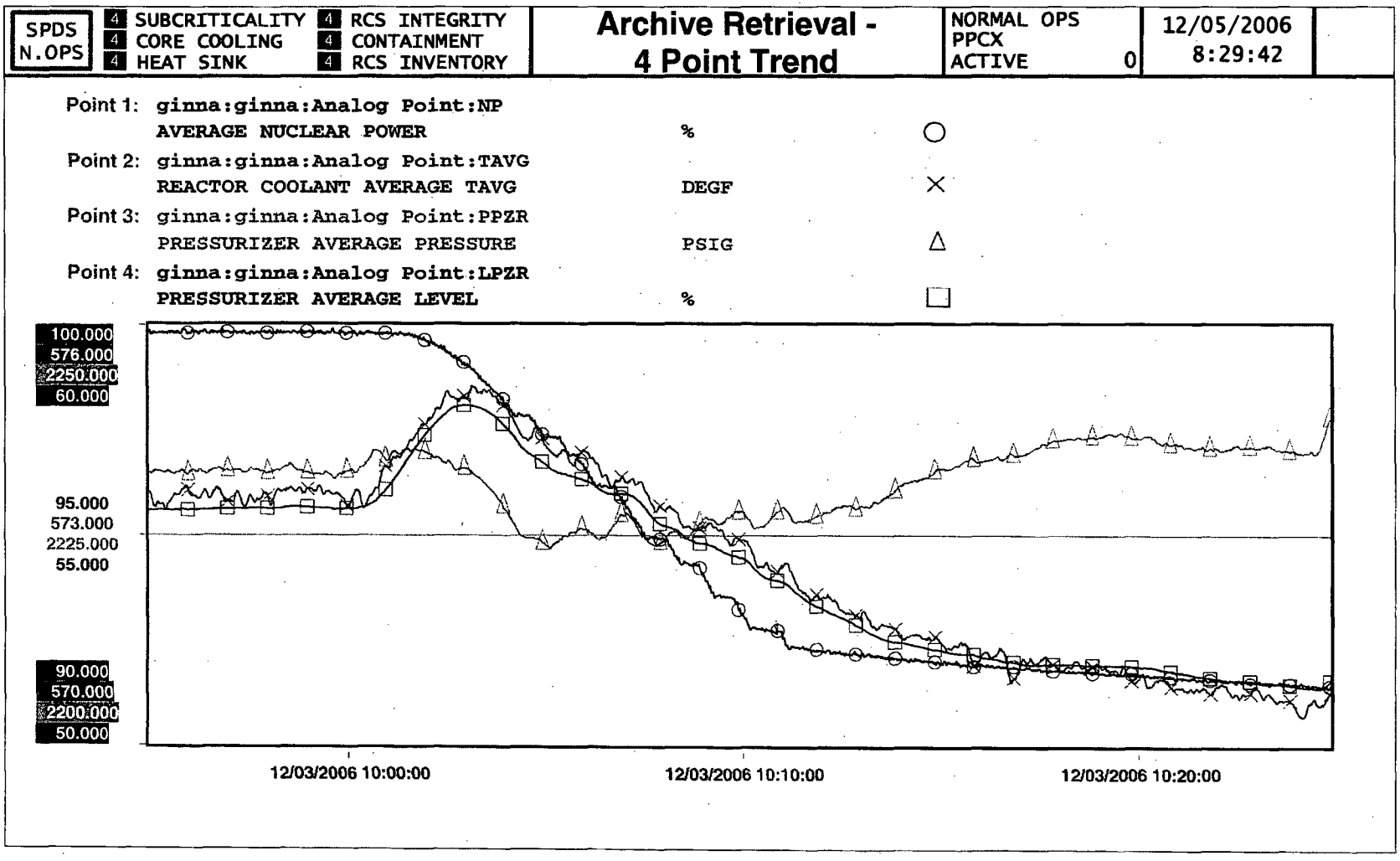
30 % MANUAL TURBINE TRIP

FIGURE 9



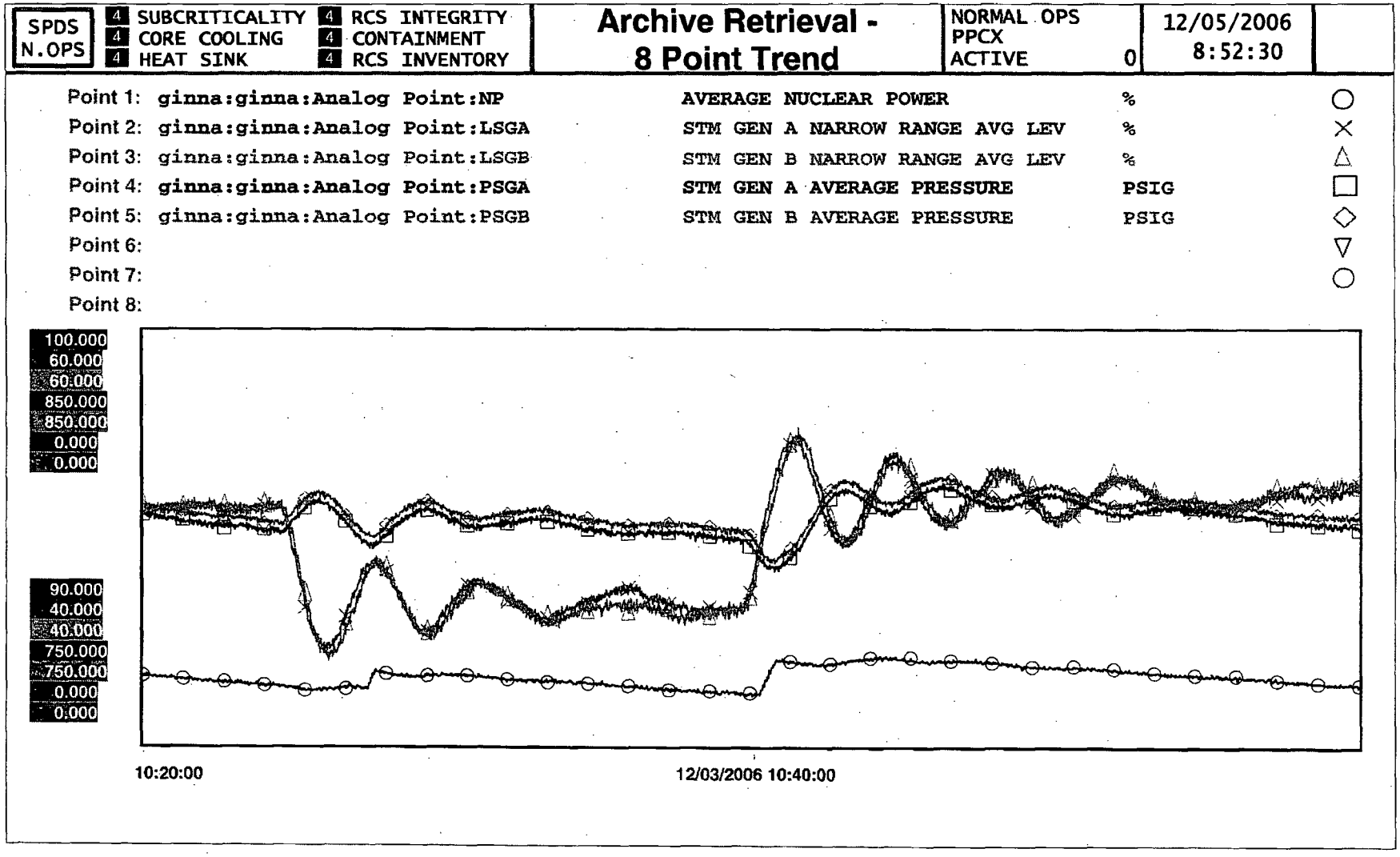
10 % RAMP DOWN AT 100% POWER

FIGURE 10



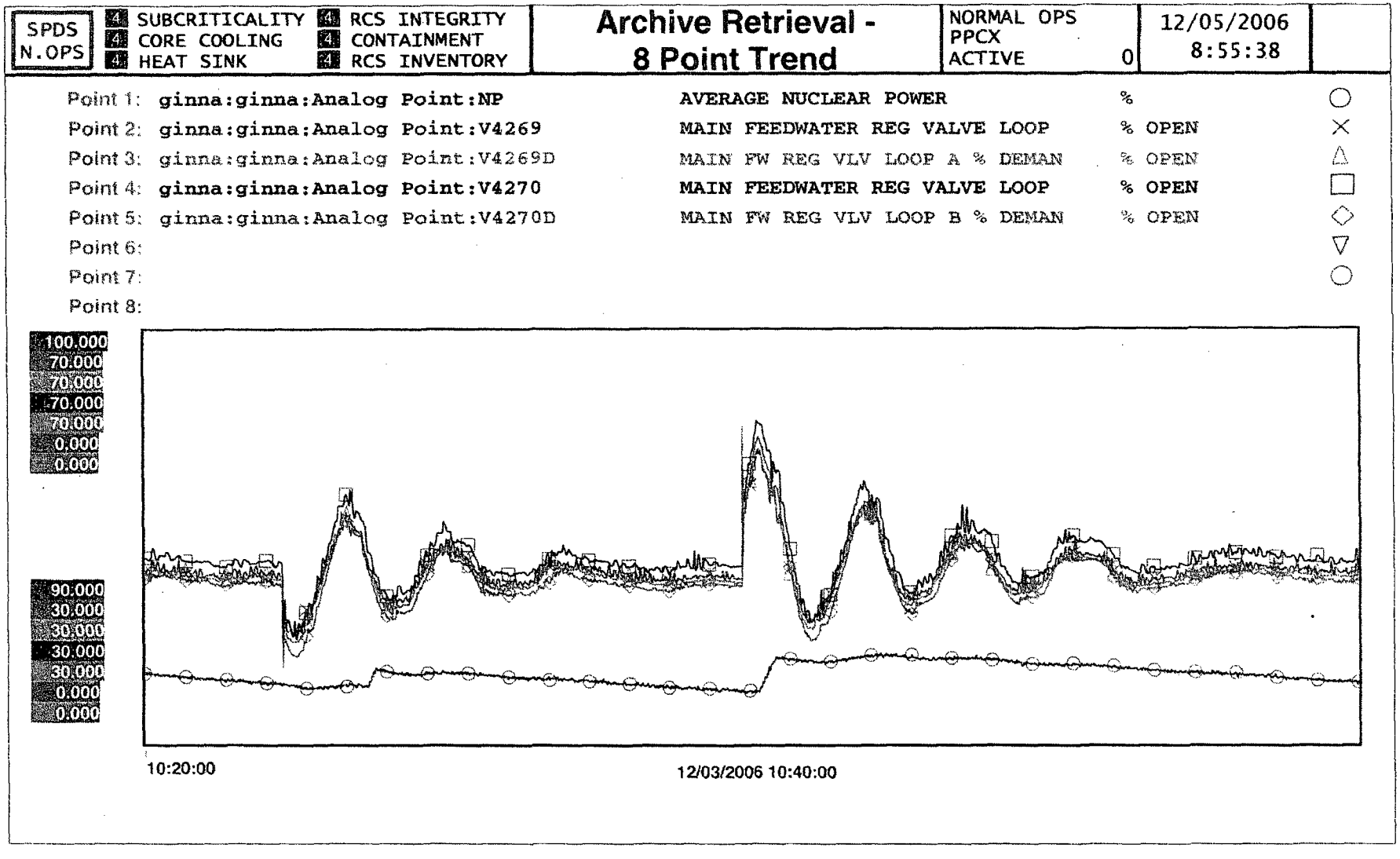
5% SG LEVEL CHANGE AT 90% POWER

FIGURE 11



5 % SG LEVEL CHANGE AT 90% POWER

FIGURE 12



10% RAMP UP TO 100% POWER

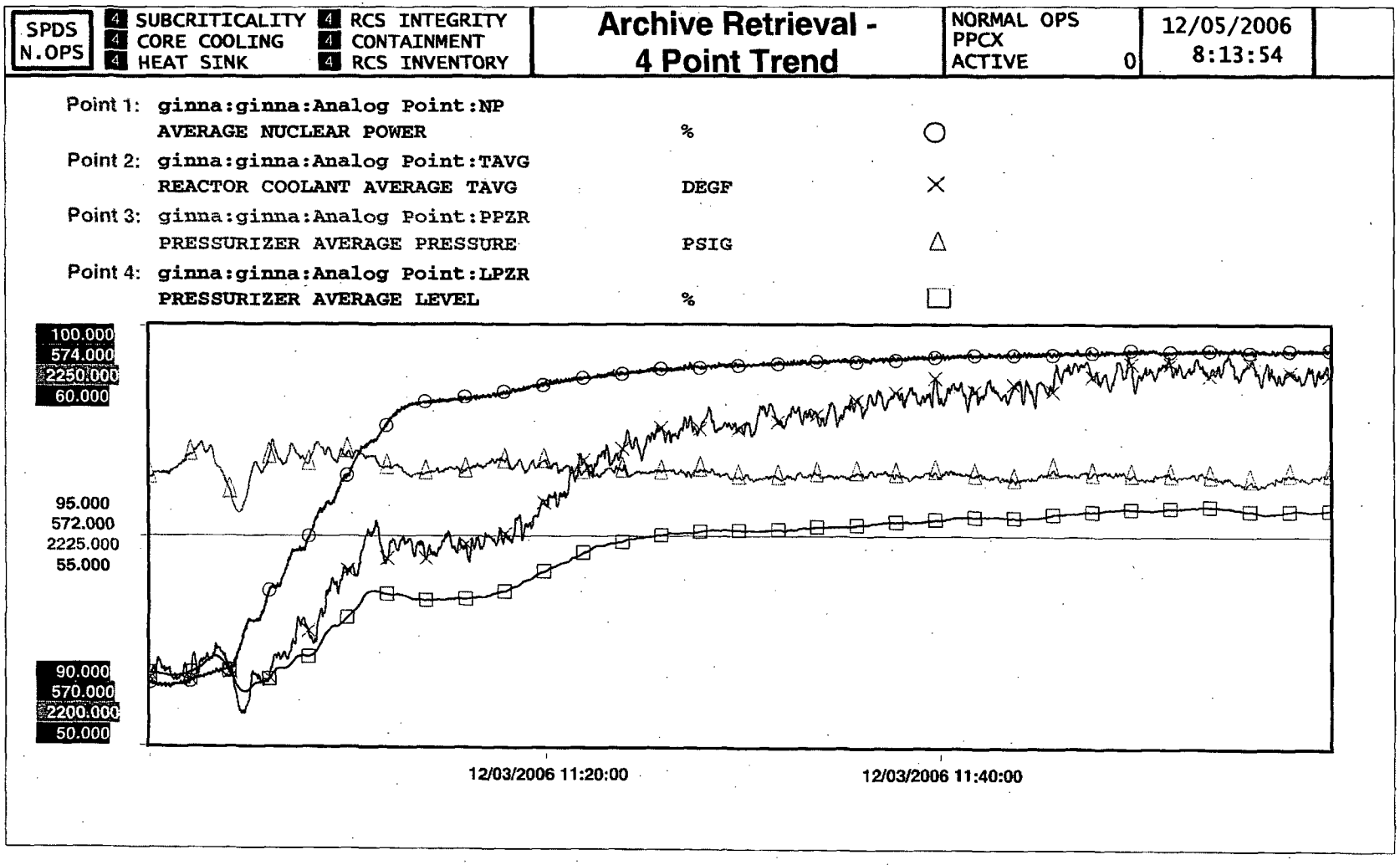



FIGURE 13