10 CFR 50.73

APS

A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear
Generating Station

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102-05763-DCM/REB
October 31, 2007

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
License No. NPF 51
Licensee Event Report 2006-003-01

Attached please find Licensee Event Report (LER) 50-529/2006-003-01 that has been prepared and submitted pursuant to 10 CFR 50.73. Revision 00 of this LER reported an automatic reactor trip on variable overpower during restoration of an out of service main turbine control valve. This supplement (Revision 01 to the LER) provides details of the subsequent root cause analysis and additional corrective actions.

In accordance with 10 CFR 50.4, copies of this LER are being forwarded to the NRC Regional Office, NRC Region IV and the Senior Resident Inspector. If you have questions regarding this submittal, please contact Ray E. Buzard, Section Leader, Regulatory Affairs, at (623) 393-5317.

Arizona Public Service Company makes no commitments in this letter.

Sincerely,

D. C. Mims

DCM/REB/gat

Attachment

cc	E. E. Collins, Jr.	NRC Region IV Regional Administrator
	M. T. Markley	NRC NRR Project Manager - (send electronic and paper)
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS

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NRR

NRC FORM 366 (6-2004)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104	EXPIRES 06/30/2007

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

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4. TITLE
Unit 2 Variable Overpower Reactor Trip During Main Turbine Control Valve Restoration

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME: None	DOCKET NUMBER: 05000
07	26	2006	2006	- 003 -	01	10	31	2007	FACILITY NAME: None	DOCKET NUMBER: 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 90

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR§ *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☒ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER (Include Area Code)
Ray E. Buzard, Section Leader, Regulatory Affairs - Compliance	(623) 393-5317

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)*	☒ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On July 26, 2006, at 07:33 Mountain Standard Time (MST), Unit 2 was in Operating Mode 1, Power Operation, at approximately 90 percent rated thermal power with main turbine control valve #2 (CV#2) closed to complete maintenance on its position transducer and linkage arm. A jumper installed in the test button circuit kept CV#2 closed during the maintenance. After removal of the jumper and CV#2 from "test", the valve was allowed to re-open resulting in a series of control system responses causing reactor power to increase rapidly. The reactor tripped on core protection calculator high variable overpower at approximately 90 percent power, approximately 18 seconds after removing CV#2 from "test". No other safety system actuations occurred and none were required.

The root cause of the event was an inadequate assessment of the risk associated with performing the valve maintenance on-line, resulting in implementation of an inadequate action plan for corrective maintenance which did not accommodate for the build up of condensate in the isolated main turbine piping associated with CV#2. This occurred due to a belief that the maintenance evolution was equivalent to control valve testing. All monthly CV testing in Unit 2 was suspended until the root cause of the plant transient was determined. A standing order was issued to prohibit performance of CV maintenance on-line, and remained in effect until adequate procedural guidance was provided for removal of a CV from service for on-line maintenance.

A similar trip event caused by a main turbine upset occurred on June 7, 2004, in Unit 3, when a main turbine electro-hydraulic system malfunction caused main turbine control and intercept valves to close, resulting in a reactor trip.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

All times in this report are approximate and Mountain Standard Time (MST) unless otherwise noted.

1. REPORTING REQUIREMENT(S):

This LER (50-529/2006-003-01) is being submitted pursuant to 10 CFR 50.73(a)(2)(iv)(A), to report a reactor protection system (RPS) (EIIS: JC) initiated reactor trip while critical on July 26, 2006, at 07:33. On July 26, 2006, at 11:20, APS made notification of the event to the Nuclear Regulatory Commission (NRC) via the emergency notification system (ENS# 42730).

2. DESCRIPTION OF STRUCTURE(S), SYSTEM(S) AND COMPONENT(S):

The main turbine (EIIS: TA) is equipped with an electro-hydraulic control (EHC) system that combines electronics and high-pressure hydraulics (EIIS: TG) to control steam flow through the turbine via main turbine stop and control valves. The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. The function of the stop valves is to shut off the flow of steam to the turbine when required, so they are either fully open or fully closed. The function of the control valves is to regulate steam flow as directed by the EHC load control unit. The control valves are operated in full arc emission mode, with each of the four valves throttled an equal amount to achieve load control. The control valves each have a control loop consisting of electronic circuitry, an electro-hydraulic servo valve, a hydraulic actuator and a linear position transducer. By use of valve position feedback control, the control valves are positioned according to the flow demand signal from the EHC load control unit, the standby control unit, or directly from the control panel during monthly valve testing.

During monthly control valve testing, each control valve is stroked from its normal approximate 40 percent open position to full closed by depressing the test button. The valve is then immediately restored to its original position as dictated by turbine load by releasing the test button. During the test, a control signal modulates the remaining three control valves as necessary to regulate main turbine first stage pressure (MTFSP). By minimizing changes in MTFSP, any turbine load swings are minimized. The resulting plant transient during the test is minimal.

The steam bypass control system (SBCS) (EIIS: JI) controls the positioning of the turbine bypass valves, through which steam is bypassed around the turbine into the unit condenser, with exception of two valves which dump steam to atmosphere. These two valves are the last to open and first to close during steam bypass operation. The system is designed to accommodate large load rejections by sensing rapid decreases in steam flow and turbine first stage pressure (turbine load index) to quickly open steam bypass control valves, based on the magnitude of the load rejection.

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The core protection calculator (CPC) (EIIS: Code JC) consists of four independent channels which generate low departure from nuclear boiling ratio (DNBR) and high local power density (LPD) reactor trip signals using two out of four coincidence logic, or two out of three, if one channel is bypassed. The CPC also provides auxiliary trips; among them, a variable overpower trip (VOPT) signal to trip the reactor when reactor power either increases at a great enough rate, or reaches a preset value. Under steady state conditions the trip setpoint will stay above the neutron power level signal by a preset value of </= to 8.0 percent rated thermal power (RTP) . When power increases or decreases the setpoint will track power by a fixed amount defined by a band function. The band function automatically adjusts the trip setpoint with increasing reactor power at maximum increasing tracking rate of less than or equal to 1 percent RTP per minute. Should reactor power increase at too rapid a rate, it will catch up with the more slowly increasing trip setpoint and cause a trip. The setpoint will also track during power reductions with a rate of decrease of </= 16.67 percent RTP per second. The VOPT circuit also includes a maximum trip setpoint that causes a trip if power reaches an allowable value of 110 percent RTP.

3. INITIAL PLANT CONDITIONS:

On July 26, 2006, at approximately 07:33, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION), operating at approximately 90 percent power. Main Turbine control valve #2 (CV #2) (EIIS: – TG) was closed to perform corrective maintenance on its failed position transducer and linkage arm. A jumper was installed on the test push button circuitry to keep CV#2 closed during the maintenance. No major structures, systems, or components were inoperable at the start of the event that contributed to the event.

Condensate accumulated in the isolated steam line of CV#2 because no condensate drain path was provided during the four hours CV#2 was closed for maintenance.

4. EVENT DESCRIPTION:

On July 26, 2006, at 07:33, following completion of maintenance, the reactor operator (RO) (utility – licensed) depressed the CV#2 test button to hold the valve closed to allow removal of the jumper. An instrumentation and control technician (utility – non-licensed) removed the jumper after which the RO released the CV#2 test button to allow the valve to open. CV#2 opened and then modulated closed along with control valves #1, #3, and #4 as directed by the turbine controls. When CV#2 opened, indicated MTFSP increased rapidly from 625 psig to 695 psig. This spike was the result of the wet steam passing through the turbine and was not indicative of an actual turbine load increase. Turbine load actually decreased, as evidenced by a generator megawatt output decrease as all four valves modulated closed. All four control valves stabilized at approximately 30 percent open within approximately 5 seconds.

The passing of the volume of wet steam combined with the control valves modulating closed then caused MTFSP to drop fast enough to cause the rate of change of turbine load index to initiate a Steam Bypass Control System (SBCS) Quick Open X2 relay actuation. The closure of the control valves resulted in a large drop in steam flow (~44 percent decrease). This rapid reduction in steam flow was large enough to actuate the SBCS Quick Open X1 relay. With both Quick Open X1 and X2 relays actuated, a Quick Open Group X was briefly generated and SBCS Valves 1, 4, and 6 responded by opening quickly then modulating closed. The quick opening of the Group X SBCS valves resulted in a large increase in steam flow that caused a drop in RCS temperature of 5 degrees. Indicated power had initially dropped from 90 percent to 88 percent and then, due to negative Moderator Temperature Coefficient (MTC), it quickly increased to 98 percent. This power, as measured by excore neutron instruments (EIIS: – IG), increased faster than the CPC VOPT band setpoint and caused the trip at 98 percent on the CPC. This resulted in an automatic reactor trip (RPS actuation) and insertion of all control element assemblies (CEA's) (EIIS: – AA). No engineered safety feature (ESF) actuations occurred nor were any required. All safety systems functioned as required.

The SBCS system operated to maintain steam generator and reactor coolant system (RCS) heat removal. Pressurizer level and pressure control systems (EIIS: AB) operated to maintain level and pressure. The main turbine EHC and SBCS responded per design during the event.

The control room supervisor (CRS) (utility – licensed) and ROs completed standard post trip actions and entered emergency operating procedure 40EP-9EO02, Reactor Trip. The CRS determined no emergency classification was required and diagnosed the event as an uncomplicated reactor trip.

Off site power remained available throughout the event as did normal heat removal through the condenser. The NRC operations center was called and notified of the event at 11:20 (reference ENS 42730). Operators stabilized the plant in Mode 3, Hot Standby, at normal operating temperature and pressure.

The event did not occur as the result of a failed or degraded system, structure, or component. The restored control valve (CV#2) and its related systems responded as designed during the event.

5. ASSESSMENT OF SAFETY CONSEQUENCES:

The plant remained within safety limits throughout the event. The primary system and secondary pressure boundary limits were not approached and no violations of the specified acceptable fuel design limits (SAFDL) occurred. No ESF actuations occurred and none were required. There

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were no inoperable structures, systems, or components at the time of the event that contributed to the event.

The event did not result in any challenges to the fission product barriers or result in the release of radioactive materials. Therefore, there were no adverse safety consequences or implications as a result of this event and the event did not adversely affect the safe operation of the plant or health and safety of the public.

The condition would not have prevented the fulfillment of any safety function and did not result in a safety system functional failure as defined by 10CFR 50.73(a)(2)(v).

6. CAUSE OF THE EVENT:

The direct cause of the event was a secondary plant transient that was initiated when CV#2 was re-opened admitting a volume of wet steam to the first stage of the turbine. CV# 2 had been closed for 4 hours during repairs to the LVDT and associated linkage. During this time the associated downstream drain valve to the condenser remained closed, allowing an accumulation of condensate in the pipe.

The root cause of the event was an inadequate assessment of the risk associated with performing the valve maintenance on-line, which led to the development and implementation of a flawed game plan that included the use of a valve test procedure that was inappropriate for the CV#2 maintenance. The valve test procedure did not address the build-up of moisture that accumulated in the steam piping during the maintenance. At the time of this event, there was no formal procedural guidance for the removal of a CV from service for on-line maintenance.

Previous success in completing on-line repairs to control valves led to a belief that use of the control valve test function would be successful in returning the valve to service. However, there were significant differences between the two prior repairs and the July 2006 Unit 2 repair as indicated below:

- In 1993, a Unit 3 main turbine CV#4 on-line repair was accomplished using the test function and jumper installation to close, hold, and restore the control valve for similar repairs. However, the Unit 3 turbine at that time operated in the partial arc admission with drain valves (EIIS – TF) that opened automatically whenever the control valves closed. Since then, turbine controls were changed to full arc admission and the respective drain valves automatically open only upon turbine trip.

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- A 1993 on-line repair was made to Unit 1 CV#1 which would not fully close during a CV test. Because the on-line repair was completed with CV#1 in the open position, steam flow through the pipe prevented moisture accumulation.

7. CORRECTIVE ACTIONS:

On July 27, 2006, all monthly CV testing in Unit 2 was suspended until the root cause of the plant transient was determined. A standing order was issued to prohibit performance of CV maintenance on-line, and remained in effect until procedural guidance was provided in 40OP-9MT02, “Main Turbine,” for removal of a CV from service for on-line maintenance which was included in a revision to 40OP-9MT02 on January 19, 2007.

A copy of the causal investigation report was provided to the Licensed Operator Continuing Training (LOCT) and Engineering Training personnel to be utilized for Operating Experience training. This information was presented to Operations personnel in the LOCT as part of the lesson plan for Operational Decision Making.

8. PREVIOUS SIMILAR EVENTS:

Arizona Public Service reported a previous event caused by a main turbine control system upset which occurred on June 7, 2004, in Unit 3. A main turbine EHC system malfunction caused main turbine control and intercept valves to close, resulting in a reactor trip on LO DNBR, LER 50-530/2004-002-01. The event was similar because the event started with a main turbine control system response. The causes were dissimilar because the prior event was the result of EHC component failure and overly conservative factors applied to the CPC which have been corrected. No other similar event has been reported to the NRC within the last three years caused by main turbine control system response.