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April 11, 1980

Re: Indian Point Unit No. 2
Docket No. 50-247

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Denton:

Attachment A summarizes the actions taken in order to comply with the 60 day requirement in the NRC Confirmatory Order of February 11, 1980. All the necessary confirmatory documentation is available at the plant site for your, or Resident Inspector's, review.

Very truly yours,

John D. O'Toole

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C. Within 60 days of the date of the Order, the licensee shall:

1. Review the steady state steam generator operating level to determine the optimum steady state level for the purpose of maximizing dryout time with due consideration for overfilling. The results of this study shall be provided to the NRC.

Response: The steady state steam generator operating level was chosen based on analyses and setpoint-type studies. This level was optimized with respect to Class 1 transients, such as load swings and load rejections, and Chapter 14 FSAR safety analyses. Many other factors entered into the selection of this normal operating level such as mass available for discharge following a secondary pipe rupture, moisture carryover considerations, and steam generator overfilling. Since all of the above were considered in the optimization of the steam generator normal water level, any change (increase) in the normal water level will, of course, cause a departure from optimum.

More detailed information, with regard to the effect of a change in steam generator level on steam generator dryout time, core uncovering time and moisture carryover is provided below.

STEAM GENERATOR DRYOUT TIME

It should be noted that an increase in nominal steam generator level (i.e., mass) is not the prime consideration in calculation of steam generator dryout time. A more important consideration is post-trip mass at the low level setpoint, which is the steam generator mass that is used in dryout calculations. A steam generator dryout calculation computes the time that is required to dissipate the liquid inventory in the steam generator below the low level setpoint due to decay heat generated in the core. Therefore, raising the low level setpoint will increase the post-trip mass and increase the steam generator dryout time.

The current Indian Point Unit 2 low level setpoint results in a steam generator dryout time of 40 minutes. An increase in the low level setpoint of 5% of the narrow range span increases the liquid mass by 2900lb, and the dryout time by about 1.3 minutes (3.8%).

Table 1 provides the detailed calculational results, which are based on best estimate decay heat. In addition, if reactor trip is assumed to occur at the normal operating level, an increase in the normal operating level would result in a commensurate increase in the dryout time.

The IP2 steam generator dryout time of 40 minutes compared to about 3 minutes for TMI, allows considerable time for IP2 operator action, in the event it is required. Operators at TMI took on the order of 8 minutes to realign valves and obtain auxiliary feedwater flow.

CORE UNCOVERING TIME

Based on generic Westinghouse analysis the time required to uncover the core, after dryout of the steam generators, is about 30 minutes. Thus

the total time available to ensure that an adequate heat sink exists, and prevent uncovering of the core, is about 70 minutes. The additional time available, due to an increase in steam generator level of 5% of narrow range is insignificant (less than a 2% increase in total time).

MOISTURE CARRYOVER

The steam generator operating water level has an important effect on moisture carryover margin. This is because of the general trend to increased moisture carryover with an increase in water level above the nominal value. This trend has been observed at a Westinghouse plant operating at slightly below full power conditions. Data obtained from this plant indicates that a water level increase of approximately 5% of span results in a 15% to 25% increase in moisture carryover. Since Indian Point Unit No. 2 is currently operating near the design limit of moisture carryover, it can be concluded that an increase in nominal operating level will result in excessive moisture delivery to the turbine.

CONCLUSION

Present steam generator water levels, both normal operation and low level trip, have been reviewed. The effect of increasing water levels has been shown to be insignificant for Indian Point Unit 2, with respect to increasing operator action time available. Furthermore, such a level increase would lead to potential operating difficulties and turbine damage due to excessive moisture carryover.

TABLE 1

Indian Point Unit No. 2 Steam Generator Dryout Calculational Results

Liquid Inventory, per Steam Generator, at 30 % (Narrow Range) Level	69,400 lb
Steam Generator Dryout Time, Based on 30% Level Trip	40.33 min
Additional Liquid Inventory Due to 5% Increase in 30% Level Trip (i.e., to 35%)	2,900 lb
Steam Generator Dryout Time Based on 35% Level Trip	41.67 min
Increase in Dryout Time Due to 5% Level Increase	1.34 min

C2. Evaluate possible co-impregnation of the charcoal in the plant's air effluent filtration systems with KI and I2 and an amine such as TEDA (triethylene-diamine) to improve the iodine removal capability of these systems. The results of this review shall be submitted to the NRC.

Response: All charcoal filtration systems at Indian Point Unit No. 2 were originally filled with charcoal co-impregnated with both KI3 and TEDA. Recently, the Central Control Room filtration system charcoal was

replaced with charcoal co-impregnated with KI and TEDA. Our charcoal supplier has indicated that the use of KI and TEDA rather than KI3 and TEDA is preferred for present day charcoal co-impregnation. Our supplier has informed us that I2 is not used in the co-impregnation process because of its highly corrosive nature. The charcoal supplier has verified that charcoal co-impregnated with KI and TEDA meets the latest requirements of Regulatory Guide 1.52, Revision 2. Therefore, as future charcoal replacements are made, we presently plan to install new charcoal co-impregnated with KI and TEDA.

C3. Evaluate effects on plant systems stability if power is reduced as much as 50%, treating power as a parameter. (For example, the effects on the feedwater flow automatic control).

Response: The IP2 plant operated at various power levels for prolonged periods of time during the initial start-up testing program. Since start-up, operation at reduced loads has occurred on several occasions as a result of equipment outages, testing, backpressure considerations, etc. It has been found that the plant can operate for prolonged periods in a stable condition at 50% power with the feedwater flow control in the automatic mode.

Plant operating history has shown that the secondary side stability and efficiency decrese as plant load decreases.

C4. Submit a schedule to implement the ATWS instrument modification justified in accordance with the Westinghouse analytical results contained in the letter from T. N. Anderson to S. H. Hanauer in NS-TMA-2182 dated December 30, 1979.

Response: The analytical results contained in the December 30, 1979 Westinghouse letter indicate that Indian Point Unit 2 can withstand the consequences of the postulated ATWS events. There are only two functions that are needed to mitigate the consequences of the most severe ATWS events prior to proceeding to long term shutdown conditions. These functions are the actuation of the auxiliary feedwater system and the tripping of the main turbine for those events that result in a potential loss of heat sink such as the loss of load or the loss of main feedwater. Normally, these functions are obtained via the reactor scram signal and through the reactor protection system. Since these are postulated to be unavailable during an ATWS, another diverse method of auxiliary feedwater initiation and main turbine trip will be installed.

The new method will be independent of the scram system and unaffected by a common mode fault in the reactor protection system. It will meet to the extent practicable the design bases for the Alternate Mitigating Systems Actuation Circuitry (AMSAC) described in section 9.2 of the December 30, 1979 Westinghouse letter. It will be installed during the Cycle 5/6 refueling outage presently scheduled for the fall of 1982, for Indian Point Unit No. 2. This is based on the following preliminary schedule:

January 1981	Complete Review and Engineering Design
April 1981	Complete Purchasing of Equipment
April 1982	Complete Delivery of Hardware
Fall 1982	Complete Installation During Refueling Outage Cycle

The above schedule is based on the assumptions and criteria used in the Westinghouse letter of December 30, 1979, referenced above. Should there be any significant changes in the scope of the ATWS instrument modification, as finally approved by the NRC, this schedule may be modified.

C5 Examine methods of establishing the highest reliability for the gas turbines and submit the results to the NRC. The licensee specifically shall:

C5 (1) Provide details of gas turbine controls, modes of operation, and other relevant information;

Response: There are three (3) gas turbines associated with the Indian Point Unit No. 2 plant. Two of these gas turbines are located at the Buchanan Substation and the third is located at the Indian Point site; Each gas turbine is located in its own enclosed building, has separate local operation panels, and "black-start" capability.

Gas turbine power can be provided to Indian Point Unit 2 from any of the three gas turbines via either of the two -13.8 Kv underground feeders or two 138 Kv overhead feeders which connect off-site power to the unit. Maximum flexibility of routing is provided by interties at the Buchanan Substation (138 Kv and 13.8 Kv buses) and at the Indian Point site (138 Kv site switchyard and gas turbine substation 6.9 Kv bus tie).

The operating mode of the gas turbines is manual. This manual start is applicable for both regular and "black-start" modes of operation.

C5 (2) Evaluate possible improvements to the starting and running reliability of the gas turbines;

Response: We are currently investigating improved maintenance and testing procedures and criteria for operability of the gas turbines. This study requires technical communications between Con Edison and the gas turbine manufacturer (Westinghouse). The expected completion date for this investigation is June, 1980, and we will report any significant findings to the Commission shortly thereafter.

C5 (3) Evaluate and initiate actions which will ensure that a gas turbine can be brought on line within one hour after loss of off-site power;

Response: Each gas turbine has "Black-start" capability. The black-start capability can be accomplished within an hour during the condition of loss of off-site power.

We are in the process of developing surveillance procedures which will demonstrate the availability/operability of the gas turbines within one (1) hour after loss of off-site power.

C5 (4) Determine how gas turbine power can be provided to Indian Point Unit 3.

Response: Similar to Indian Point Unit 2, gas turbine power can be provided to Indian Point Unit 3 from any of the three gas turbines via either of the two -13.8 Kv underground feeders or two 138 Kv overhead feeders which connect off-site power to the unit. Maximum flexibility of routing is provided by interties at the Buchanan Substation (138 Kv and 13.8 Kv buses) and at the Indian Point site (138 Kv site switchyard and gas turbine substation 6.9 Kv bus tie).

C5 (5) Evaluate the limitation that Indian Point Unit 2 not be operated if the gas turbines are out-of-service.

Response: The present Indian Point Unit No. 2 Technical Specification requires that one gas turbine generator shall be operable at all times; if this requirement cannot be met, then, within the nex seven (7) days, either the inoperable condition shall be corrected or an alternative independent power system shall be established. Of the above mentioned requirements cannot be satisfied, the reactor shall be placed in the hot shutdown condition utilizing nonmal operating procedures. If the previously mentioned requirements cannot be met within an additional 48 hours, the reactor shall be placed in the cold shutdown condition utilizing normal operating procedures.

The diversity and flexibility inherent in the offsite power supply system available to IndianPoint make it a highly reliable system. Independent power sources enter the Buchanan Substation (located adjacent to the site) from the Consolidated Edison power grid, and two (2) 138 Kv overhead transmission lines and two (2) 13.8 Kv underground feeders supply the Indian Point site from the substation. Existing inter-ties permit cross-feeding from any incoming power line to any unit. Indian Point Unit No. 2 is designed to maintain a safe shutdown condition and mitigate postulated accidents even without the availability of the offsite power supply. This emergency power is provided by three onsite diesel generators. The gas turbines, therefore, provide a third contingency AC power source available to the site in the highly unlikely event that the offsite power source is lost and all three diesel generators are inoperable. It should be noted that any one of the three (3) gas turbines has more than enought capacity to operate engineered safeguards equipment and maintain the plant in a safe shutdown condition.

Therefore, considering the probability of having both the offsite power system and all three diesel generators inoperable during a specific seven day period when all three gas turbines might be inoperable, we believe that the present technical specification limitations on gas turbine operability are sufficient.

C5 (6) Establish an on-site group reporting to offsite management. The function of the group shall be to examine plant operating characteristics, NRC bulletins, Licensing Information Service advisories and other appropriate sources which may indicate areas for improving plant safety. Where useful improvements can be achieved, the group shall also develop and present detailed recommendations for revised procedures, equipment modifications or other improvements.

Response: An On-Site Safety Review Group has been established to perform the functions indicated above. This group consists of three (3) Consolidated Edison employees and three (3) Authority employees. Each group of three consists of one (1) Senior Engineer with approximately 5 to 7 years technical experience and 2 other individuals each with approximately 1 to 2 years technical experience.

The group will operate as a single committee of 6 with the Chairman of the committee alternating between Consolidated Edison Senior Engineer and Authority Senior Engineer. The Senior Engineer shall report to the Power Authority Senior Vice President Nuclear Generation and the Consolidated Edison Vice President, Power Generation. Reports and recommendations issued by the on-site committee shall be jointly distributed to both Consolidated Edison and Authority managements. Events occurring on either unit will be reported to both management organizations.

Tasks applicable to both plants shall be reviewed by the full 6-member committee with subsequent plant specific actions monitored by the respective plant group of 3.

Consolidated Edison will have its group of 3 in place by April 11, 1980.

Detailed procedures governing the operation of the group will be developed in conjunction with the Authority.

A7. Require that all reactor operators and senior operators conduct simulator training and in-plant walk through of the following emergency procedures. The in-plant walk-throughs shall be completed prior to the next reactor startup following issuance of the Order, or within thirty days of the date of issuance, whichever occurs first. Those reactor operators and senior reactor operators who have not received simulator training within the past three months on these items shall be given such simulator training within 60 days of the date of the Order:

a. Plant or reactor startups to include a range wherein reactivity feedback from nuclear heat addition is noticeable and heat up rate is established.

b. Manual control of steam generator level and/or feedwater during startup and shutdown.

c. Any significant (10%) power change using manual rod control

d. Loss of Coolant

(i) including significant PWR steam generator leaks
(ii) inside and outside containment
(iii) large and small, including leak rate determination
(iv) saturated reactor coolant response (PWR)

e. Loss of core coolant flow/natural circulation

f. Loss of all feedwater (normal and emergency)

g. Station blackout

h. Anticipated Transients Without Scram (ATWS)

i. Stuck open relief valve on secondary side

j. Intersystem LOCA

Response: Reactor operators and senior reactor operators have received simulator training as called for above.

The necessary documentation was reviewed, and found acceptable, by the NRC's resident inspector.