William J. Cahill
Vice President

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May 9, 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 90-day requirement in the NRC Confirmatory Order of February 11, 1980.

Attachment B is a revised answer to previously submitted 60-day item C.1 dealing with steam generator operating level. Dryout time increase is 3.0 minutes rather than the 1.34 minutes previously submitted.

Very truly yours,

William J. Cahill, Jr.
Vice President

Attach.

ATTACHMENT A

D. The following measures shall be implemented within 90 days of the date of the order:

1a. The licensee shall establish the on-site emergency preparedness manning levels on each shift as contained in Table 1 attached to this Appendix.

Response: Consolidated Edison will provide the required on-shift manning levels by May 11, 1980.

1b. Power Authority and Consolidated Edison shall jointly arrange to provide additional personnel as contained in Table 1 available to the plant on call within 60 minutes.

Response: Consolidated Edison and the Power Authority will jointly provide the required additional on-call personnel by May 11, 1980.

2. The Power Authority and Consolidated Edison shall jointly review and identify the significant differences between Indian Point Unit 2 and Unit 3 and shall evaluate these differences in light of present regulatory standards and requirements. Consolidated Edison shall provide a justification for the design differences or shall recommend design changes.

Response: In order to identify significant design differences between Unit 2 and Unit 3, Consolidated Edison and the Power Authority performed a functional review of existing plant structures and systems required for reactor protection or engineered safeguards or whose failure would result in Part 100 type events. The results of this review are presented in Appendix 1 of this Attachment.

Subjects of recent NRC generic review programs such as Emergency Planning, Security and Fire Protection were not considered in this review. Both Units have programs for these areas which have recently been reviewed and approved by the NRC as satisfying current requirements.

3. The licensee shall establish a temporary on-site inter-disciplinary review group consisting of, as a minimum, representatives from the NSSS vendor, the architect-engineer and the plant maintenance and operations staffs. This group shall review and concur in all existing plant emergency procedures. This group shall also review and concur in changes to emergency procedures. Emergency changes may be approved in accordance with current licensee requirements, but shall be subsequently submitted for approval by the review group.

Response: Consolidated Edison and The Authority will jointly establish a temporary inter-disciplinary review group for both Indian Point Unit 2 and Unit 3 by May 11, 1980.

Attachment A

APPENDIX 1

INDIAN POINT UNITS NO. 2 & 3

COMPARISON OF SIGNIFICANT DIFFERENCES

TABLE OF CONTENTS

System: Chemical and Volume Control

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. CVCS/RCS pressure boundary:		
a) Two series check valves in each of the two charging lines downstream of the regenerative heat exchanger (tube side);	a) One check valve upstream and one check valve downstream of the regenerative heat exchanger (tube side);	1. For each case, the difference in valve arrangement results in a differently defined primary system pressure boundary (i.e., the boundary between class 1 and class 2 systems). Basically for Unit 2, the referenced heat exchangers are included in the defined primary system pressure boundary, whereas, for Unit 3, they are outside the defined pressure boundary. The heat exchangers for both units are identical and designed to primary system design requirements. In addition, the actual piping boundary where the piping design pressure changes from 2500 psig to 600 psig is the same for both units.
b) Two series fail closed valves on the letdown line upstream of the regenerative heat exchanger (shell side);	b) One fail closed valve upstream and three parallel fail closed valves downstream of the regenerative heat exchanger (shell side);	
c) Two series fail closed valves on the excess letdown line upstream of the excess letdown heat heat exchanger (tube side).	c) One fail closed valve upstream and one fail closed valve downstream of the of the excess letdown heat exchanger (tube side).	The defined pressure boundaries discussed above for both units, each satisfy regulatory requirements. Also both units have Quality Assurance and Inservice Inspection Programs appropriate for their respective arrangements.
2) Recirculation system for Boron Injection Tank.	2) None.	2. This system was required only on Unit 3 because its Boron Injection Tank is an in-line tank with no level indication located downstream of the safety injection pumps. Its contents are required to be continuously recirculated with the Boric Acid Storage Tank to assure operability. The Indian Point 2 Boron Injection Tank is a suction tank with level indication located upstream of the safety injection pumps. No recirculation system similar to Unit 3 is required to assure operability

System: Service Water

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Six Service Water Pumps at intake structure and three backup Service Water Pumps in the discharge canal.	1. Six pumps at the Intake structure.	1. In the early 70's, there was a reserve fleet of ships moored North and South of the plant in the Hudson River. The three service water pumps in the discharge canal were added during the licensing review on Unit 3 to provide additional protection in the unlikely event that one of those ships broke loose and crashed into the intake structure. These ships have long since been removed from the area. The probability of a ship crashing into the Unit 2 Intake structure is very small. Additionally, there are hose connections on the service water systems of Units 1, 2 and 3, which would allow Unit 2 to tap into either Unit 1 or 3 service water systems, if necessary.

System: Auxiliary Feedwater

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. AFWS Design	1. AFWS Design	1. In response to the recommendations of the NRC's Bulletins and Orders Task Force, Con Edison will by 8/11/80 a) upgrade the auxiliary feedwater pump actuation logic and flow indication to meet safety grade requirements, and b) power the regulator valves from Class 1E Buses.
a) Auxiliary Feedwater pump actuation logic and flow indication meets safety grade requirements.	a) Auxiliary Feedwater Pump actuation logic and flow indication meets control grade requirements.	
b) Regulator valves are on Class 1E Buses.	b) Regulator valves not powered from Class 1E Buses.	
2. City water system valves on suction to the auxiliary feedwater pumps are powered from Class 1E Buses.	2. City water system valves on suction to the auxiliary feedwater pumps are not powered from Class 1E Buses.	2. A Class 1E power supply is not required for these valves since the city water system is a backup system (to the condensate storage tank). If for some reason the condensate storage tank is not available and the normal power supply to these valves is lost, there is sufficient inventory in the steam generators (approximately thirty minutes) to allow for reconnection of the buses to a Class 1E source or for manual operation of the valves.

System: Component Cooling Water

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Split header design with 3 main component cooling water pumps, 4 auxiliary component cooling pumps, and 2 component cooling heat exchangers-because of the split header arrangement additional equipment is also provided (double the Unit 2 amount).	1. Single header with 3 main component cooling water pumps, 2 auxiliary component cooling pumps, and 2 component cooling heat exchangers.	1. Both the Unit 2 and Unit 3 designs can accomodate either a single active or a single passive failure. In each case the system is a closed system, seismic class I, missile protected inside containment and a low energy system (operates at 70-100°F and designed for 150 psig). Loss of component cooling has been analyzed in the FSAR. (page 14.3.4-23 for Unit 2 and page 14.3.4-25 for Unit 3). The analysis shows that an alternate heat removal path (containment fan coolers) exists. The system is also not required during the injection phase of a LOCA. There are also permanent connections available to provide city water for cooling the RHR pumps, the SI pumps and the charging pumps. There are also flanged connections from the service water and/or fire protection system for cooling these pumps.

System: Residual Heat Removal

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Separate discharge line from each RHR heat exchanger to low head injection lines.	1. Common discharge line from RHR heat exchangers to low head injection lines.	1. Both the Unit 2 & Unit 3 systems can accommodate either a single active or a single passive failure. There is sufficient flow through alternate flow paths to satisfy core cooling requirements (Ref: Unit 2 & Unit 3 FSAR Table 6.2-7b).
2. Separate outlet from each RHR heat exchanger to the high head injection system.	2. Common outlet from RHR heat exchanger discharge to the high head injection system.	2. Both the Unit 2 & Unit 3 systems can accommodate either a single active or a single passive failure. There is an alternate flow path to the safety injection pumps (by-passing the RHR heat exchangers). Heat is removed from the core by boil-off of water to the containment. There is sufficient heat removal capacity via the containment fan cooler units to compensate for the loss of the heat removal capability of the RHR heat exchangers. (Ref: Unit 2 and Unit 3 FSARs-Table 6.2-7b and Section 14.3.4).

System: Residual Heat Removal

INDIAN POINT 3	INDIAN POINT 2	REMARKS
3. Pressure interlock to provide automatic closure of RHR Suction Valves MOV's-730 & 731 whenever RCS pressure increases above RHR design pressure and a pressure interlock to prevent opening of 730 & 731 until the RCS pressure has decreased to below 450 psig.	3. Pressure interlock to prevent opening of 730 & 731 whenever the RCS pressure is greater than 450 psig.	3. Both Unit 2 and Unit 3 designs incorporate a pressure interlock to preclude opening these valves while the RCS pressure is greater than the RHR design pressure to avoid overpressurizing the RHR System. The Unit 3 design also has an automatic closure feature for 730 & 731 upon increasing RCS pressure. The auto-close feature is not required for Unit 2 since: (1) during plant startup existing procedures require closing and deenergizing valves 730 & 731 prior to increasing RCS pressure above RHR system design pressure, and (2) the existing RCS overpressure protection system (OPS) and the existing RHR relief valve capacity are adequate to preclude RHR system overpressurization should the RHR system be in communication with the RCS during a design basis overpressurization transient.
4. Containment sump isolation is accomplished via the first containment isolation valve (885A) located outside containment at the containment wall within a container which is an extension of the containment boundary.	4. Unit 2 has a separate 18" motor operated butterfly valve (1805) located in the containment sump for isolation. Two containment isolation valves (885A&B) are located outside containment similar to Unit 3 except that 885A is not required to be located within a container because of the existence of valve 1805.	4. Both designs are acceptable. Each arrangement has two series containment isolation valves located outside containment for the sump discharge line. Unit 2 has a third valve in series located inside containment. For either unit, should any one of these valves be found failed closed, the alternate (and perferred) recirculation path (using the independent internal recirculation pumps and the recirculation sump) exists.

System: Safety Injection

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Eight Hi Head cold leg injection lines.	1. Four Hi Head cold leg injection lines.	1. Both designs meet the 10CFR50 Appendix K criteria for emergency core cooling systems.
2. Boron injection tank situated on discharge of safety injection pumps - special orfice in discharge line for flow balance.	2. Boron injection tank (BIT) located on suction side of safety injection pumps.	2. Unit 3 BIT was relocated to discharge side of safety injection pumps to improve the time it takes borated water to get into the reactor coolant system following a steamline break. Although borated water will reach the RCS sooner with the Unit 3 design, both arrangements satisfy the design criteria for borating RCS following a steamline break (that is, DNB limits are met, radiation releases are within the requirements of 10CFR100, and there is no return to criticality for the "credible steam break").
3. No automatic control of crossover valves 851A & B on discharge or SI pumps.	3. Automatic control of crossover valves 851A & B on discharge of SI pumps.	3. The Unit 3 design utilizes safety injection system flow orifices to balance flow through the safety injection discharge headers for any combination of operating safety injection pumps. The Unit 2 design is such that upon failure of safety injection pump 21 or 23, the appropriate crossover valve will automatically close to permit the "middle" safety injection pump 22 to feed the

System: Safety Injection

INDIAN POINT 3	INDIAN POINT 2	REMARKS
		main discharge header of the failed pump. The time delay circuits for the auto-close feature are set sufficiently high to permit loading of safety injection pumps on the diesel generators for the loss of offsite power case. Both of the designs are acceptable and are capable of withstanding a single failure in the safety injection pump/ crossover header valving arrangement.

System: Diesel Fuel Oil Transfer

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. All three diesel generator fuel oil transfer pumps are automatically connected to 1E power supplies.	1. All three diesel generator fuel oil transfer pumps are stripped on loss of offsite power or SI, but can be reconnected to 1E power supplies.	1. Each diesel generator has a fuel oil storage day tank which when filled to capacity has about a 2 two hour supply of fuel oil. There is a low level alarm which alerts the operator in the control room when the tank is 50% full-(1 hour supply of fuel oil). The fuel oil flows from the day tanks to the diesel generators by gravity feed. Since, after receipt of the low level alarm, there is approximately 1 hour to reconnect the fuel oil transfer pumps to a 1E power supply, automatic connection is not required.
2. Each of the 3 fuel oil transfer pumps is "unitized" to its own day tank and diesel generator.	2. Any fuel oil transfer pump can supply any day tank for any diesel generator. Operation of the 3 transfer pumps is controlled by a common selector switch.	2. As discussed previously, there is at least a one hour supply of fuel oil in each diesel generator day tank. Even if the selector switch were to fail, there is sufficient time to bypass the failed switch contacts. Nevertheless, to improve reliability, it is planned to accomplish modifications at next Unit 2 refueling outage to disconnect the existing common selector switch and provide individual selector switches for each of the three fuel transfer pumps. The additional flexibility of being able to supply any diesel generator's day tank from any fuel transfer pump will be maintained.

System: Tornado Protection

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Effects of tornado loads in the design of category I structures was a licensing requirement.	1. Such loads were not a licensing requirement for Unit 2.	1. Although there was no licensing requirement, tornado protection is provided for Indian Point 2 in the following ways: a) The containment building is inherently capable of meeting the tornado protection criteria. b) Natural protection from high winds is afforded the control building, the primary auxiliary building and the Diesel Generator Building since they are protected by the turbine building to the west, the Indian Point 1 and the Indian Point 3 buildings to the South, the rising hillside to the East, and the Unit 2 containment building and rising hillside to the North.

System: Seismic Instrumentation

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Seismic Instrumentation was installed in the containment building per the requirements of Regulatory Guide 1.12 (April 1974).	1. None	1. Both units are located at the same site. There is no need to have a set of instrumentation in each plant because information recorded at Unit 3 is applicable to both plants. There is a Unit 3 procedure (PEP-S-1) which requires notification of the Unit 2 control room operator if a seismic event has been recorded. This philosophy is consistent with the requirements of Regulatory Guide 1.12 and ANSI Standard N18.5.

Indian Point Units No. 2 & 3
Comparison of Significant Differences

System: Radiation Monitoring

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Gas and particulate radiation monitoring system in control room.	1. None.	1. Con Edison is planning to provide a gas and particulate radiation monitoring system in the control room at the next refueling outage.

System: Ventilation

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Two 60% capacity HVAC units for the Unit 3 control room.	1. Two 50% capacity HVAC unit for the combined Unit 1-2 control room.	1. The Unit 2 Control Room shares a common enclosure with the Unit 1 Control Room. As described in the response to Question 7.19 in the Unit 2 FSAR, either the Unit 1 or the Unit 2 air conditioning unit is capable of maintaining the functional capacity of the Control Room (ie temperature less than 120°F). The Unit 3 Control Room air conditioning system is also designed to maintain the functional capacity of the Control Room under all conditions (see Unit 3 FSAR Section 9.9).

System: Piping Design Criteria

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Dynamic analysis of Reactor Coolant Loop	1. Dynamic analysis of Reactor Coolant Loop	1. Reactor coolant loops of Units 2 and 3 are structurally indistinguishable. Unit 2 design was validated by Unit 3 dynamic analysis. (see Unit 2 FSAR Question 1.9).
2. Dynamic analysis of 2" high head safety injection and 6" or larger Class 1 lines. Static analysis of all other piping systems.	2. Static design of all piping systems. Verification of static design by dynamic analysis for selected worst case systems. Portions of the following systems were dynamically analyzed: a) Safety injection b) Residual heat removal c) Service water d) Accumulator discharge e) Containment Spray f) Containment Cooling (See Unit 2 FSAR Question 1.9)	2. Unit 2 static design is based on span charts limiting seismic stress to 3000 psi. Also, frequency criteria used to keep piping fundamental frequency outside of structure frequency. The conservative Unit 2 design criteria resulted in a large number of seismic restraints (550 as compared to 150 on Unit 3). Many of these snubbers are being removed currently by reanalysis and comparison with Unit 3.

System: Piping Design Criteria

INDIAN POINT 3	INDIAN POINT 2	REMARKS
3. Load Combinations a) Normal: Dead Weight, Thermal, Pressure b) Upset: Normal + OBE c) Faulted: Normal + SSE d) Faulted: Normal + Pipe Rupture e) Faulted: Normal + Pipe Rupture + SSE	3. Load Combinations a) Normal: Dead Weight, Thermal, Pressure b) Normal + OBE c) Normal + SSE d) Normal + Pipe Rupture	3. IP2 FSAR criteria did not require combination of SSE & pipe rupture loads. However, it can be shown by comparison to Unit 3 that the Unit 2 design is adequate for such a combination. (Unit 2 FSAR Question 1.9). The Reactor Coolant Pipe Layout for Unit 2 and Unit 3 are structurally indistinguishable. Some modifications have been made to the Unit 3 S.G. & RCP supports in one loop based on a dynamic analysis for combined blowdown & SSE case. The effect of these modifications is strengthening of certain local areas in RCS & SG support system to gain additional margin for combined SSE & pipe rupture load. Since the Unit 3 analysis, however, was overly conservative in that the absolute summation of intra-model responses was used, we are reviewing whether similar modifications would significantly improve the capability of the support systems on Unit 2.

Indian Point Units No. 2 & 3
Comparison of Significant Differences

System: Electrical Separation

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Electrical a) Each Diesel Generator is located in its own compartment.	a) Diesel Generators are not compartmentalized. However, oil splash shields have been erected between the diesel generator units. The diesel generator building has also been fire-proofed. Back flow prevention check valves are being installed on drain lines.	1. Con Edison is installing for Unit 2 an alternate shutdown system which, when combined with any of three available gas turbines, will provide the capability to attain and maintain a safe shutdown condition independent of all offsite power and onsite emergency diesel generators . The system will also be electrically independent of and physically separate from the control room, the cable spreading room, the switchgear room, the electrical tunnel, the electrical penetration area, and the Diesel Generator Building. The gas turbines can also be used to power Unit 3 equipment.
b) Flight and supervisory panels upgraded to IEEE-420.	b) During licensing review, a mechanistic failure analysis was performed on the flight and supervisory panels. Specific protective features (e.g. physical barriers) were incorporated into the final plant design. Various administrative controls and technical specifications were also adopted.	
c) Cable raceways have unitized routing throughout -separate channels for each train. Minimum separation distance of one foot. There are two electrical tunnels.	c) Separation is provided on a function by function basis. There is a minimum two channel raceway throughout with a third or fourth raceway provided at points where required. Minimum separation distance of one foot or metal barrier. There is one electrical tunnel.	

System: 480 Volt A.C. Distribution

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Diesel connects to 480 volt safeguards Bus 3A via Bus 2A and bus tie 2AT3A; Each safeguard pump is supplied via a single circuit breaker.	1. Diesel connects to 480 Bus 2A and 3A via two separate diesel output breakers; Service water pumps 22 and 25 and SI pump 22 can be powered directly from Bus 2A or 3A via separate circuit breakers.	1. Both designs meet present criteria.

Indian Point Units No. 2 & 3
Comparison of Significant Differences

System: 125 Volt D.C.

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. 3 batteries	1. 4 batteries	1. The Power Authority is planning to install a fourth battery during the next Unit 3 Refueling/Maintenance outage.
2. Unitized design with no automatic transfers (each battery provides control power to only one Diesel Generator and its associated 480v switchgear).	2. Automatic D.C. transfers between redundant batteries 21 and 22. (Would maintain all safeguards loads on loss of a D.C. feed).	2. Con Edison, per letter dated April 23, 1980, will modify the Unit 2 design to eliminate automatic transfer of loads between batteries 21 and 22. Under the proposed system, which will utilize existing batteries 23 & 24, at least two of the four batteries would have to fail before a single Unit 2 diesel generator or 480v switchgear would be lost. The existing Unit 3 and the proposed Unit 2 designs both satisfy the requirements of Regulatory Guide 1.6.

System: 120 Volt A.C.

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. 3 Independent inverters with a fourth instrument bus supplied from a safeguard MCC via a constant voltage transformer. A single alternate power source from the AC lighting distribution system is available to provide backup AC power to the instrument buses one bus at a time.	1. 4 Independent static inverters each backed by an independent battery. Each inverter contains a static transfer switch which allows the 120 VAC bus to be fed directly from 1 of 4 independent alternate AC power sources. There is a bypass switch at each inverter which allows manual transfer to the alternate AC power source independent of the static transfer switch.	1. The Unit 3 design is being upgraded to power all four instrument busses from separate battery banks thus increasing the reliability of the vital instrument bus power source. Both the present Unit 2 design and the proposed Unit 3 designs meet present criteria.

System: Protection Logic

INDIAN POINT 3	INDIAN POINT 2	REMARKS
1. Diesel Generators connect onto 480 volt buses on undervoltage.	1. Diesel Generators start and idle on undervoltage but connect onto Buses only on undervoltage with "SI" or "UNIT TRIP".	1. Both designs meet present criteria.
2. Diesel sequencing logic is unitized and located at switchgear (three separate logic trains).	2. Two separate diesel sequencing logics located in control room; signals from either actuate all safeguards bus loads.	2. Both designs meet present criteria.

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 ~~1.5~~ 3.0 minutes (~~3.8%~~ 7.5%).

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%~~ approximately a 4% 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	43.33 ~~41.67~~ min
Increase in Dryout Time Due to 5% Level Increase	3.0 ~~1.34~~ min