15.0 CONSTRUCTION

Such environmental effects as might be associated with the construction stage of Indian Point Unit No. 3 have already occurred since the unit has been under construction since August, 1969. Since the construction is well advanced, a substantial commitment of economic resources has already been made in the Unit. A brief review of the completed construction activities follows:

15.1 Status of Construction

Those construction activities which have taken place during the year and a half since the issuance of the construction permit include the construction of the foundation for the vapor containment liner, pouring of internal concrete within the vapor containment building, and the erection of the polar crane (see Figures 34 and 35). More recently, the commencement of the placement of major equipment has taken place within the vapor containment building, including two of the four steam generators (Figures 36 and 37) and the reactor coolant pumps supports. At present, preparations for the placement of the reactor pressure vessel are underway (Figures 38 and 39).

Turbine hall construction has proceeded to the point where the building is enclosed (Figures 40 and 41) and preliminary piping installation is underway (Figure 42). The turbine generator stator and rotor have been delivered and located within the turbine hall (Figures 43 and 44). Tubing of the condenser has started. Other structures such as the primary auxiliary building, waste holdup tank pit, control room building, and fuel handling building are in earlier stages of construction. Overall estimates of the total percentage of Unit No. 3 construction completed to date is about 50%, with the expenditure as of May 31, 1971, approximately 115 million dollars. An overall aerial view is given in Figure 45 which illustrates the status of construction as of January, 1971.

From the above, it can be seen that the construction of Indian Point Unit No. 3 is well underway. The contractor, Westinghouse Electric Corporation, is estimating completion of the major portion of the construction operations by February, 1973, at which time, it is planned that the reactor coolant system hydrostatic test will be performed. It is estimated that the testing period between this hydrostatic test and plant acceptance will be approximately one year in duration. Thus the target date for full power operation is the first quarter of 1974.

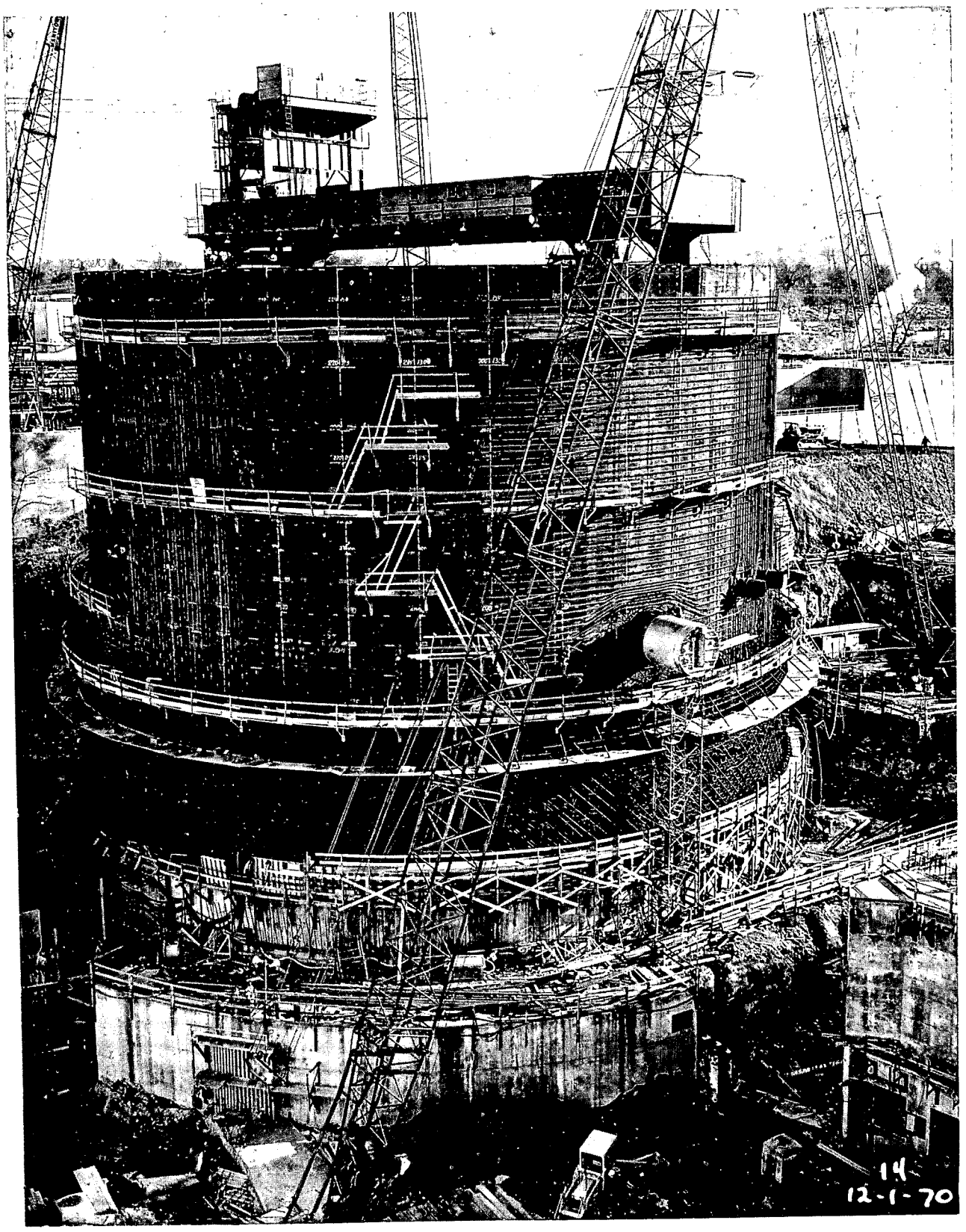

Figure - 34 Exterior view of the Vapor Containment Building showing rebar work and the personnel lock

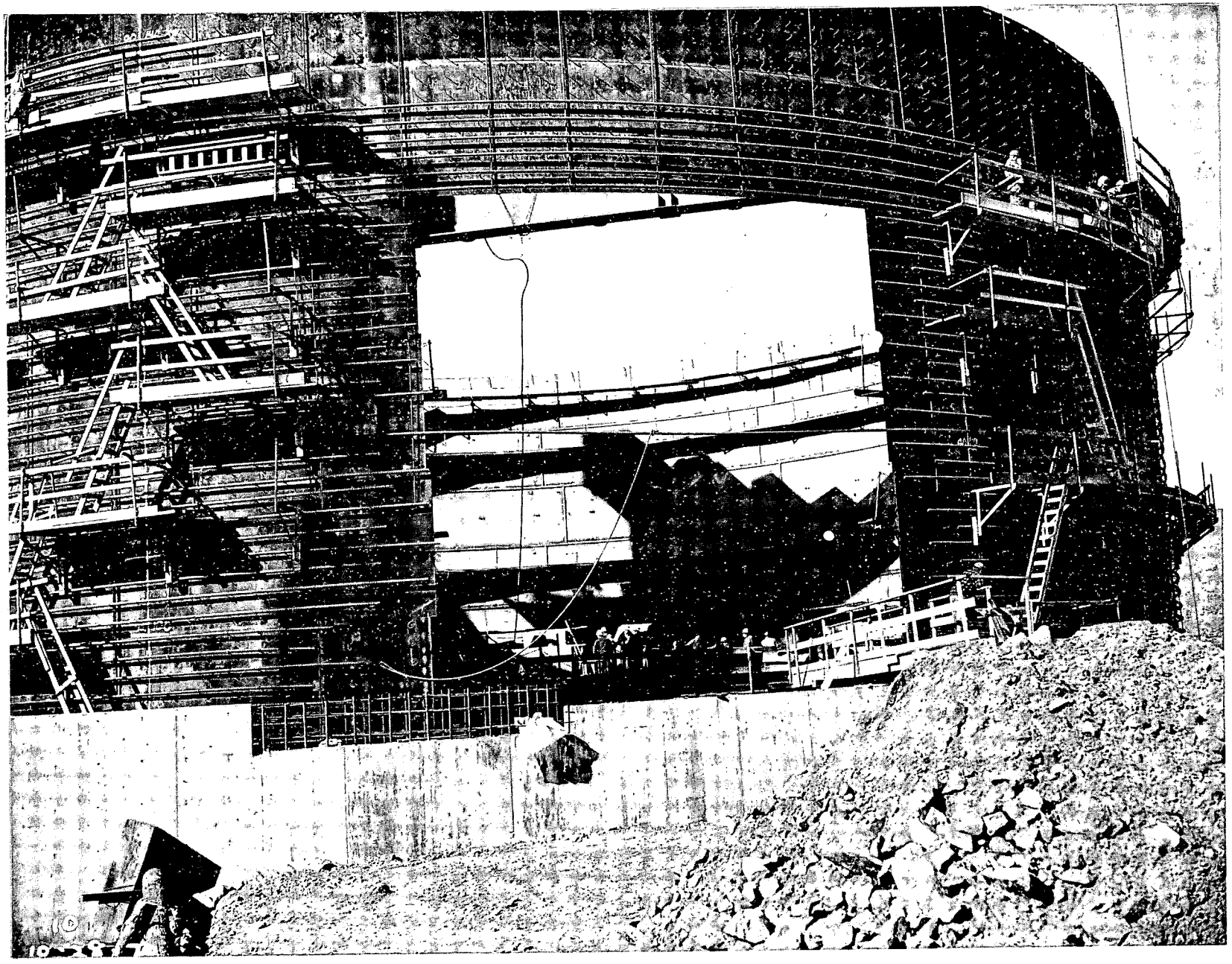

Figure - 35 Vapor Containment Building shield wall being erected.

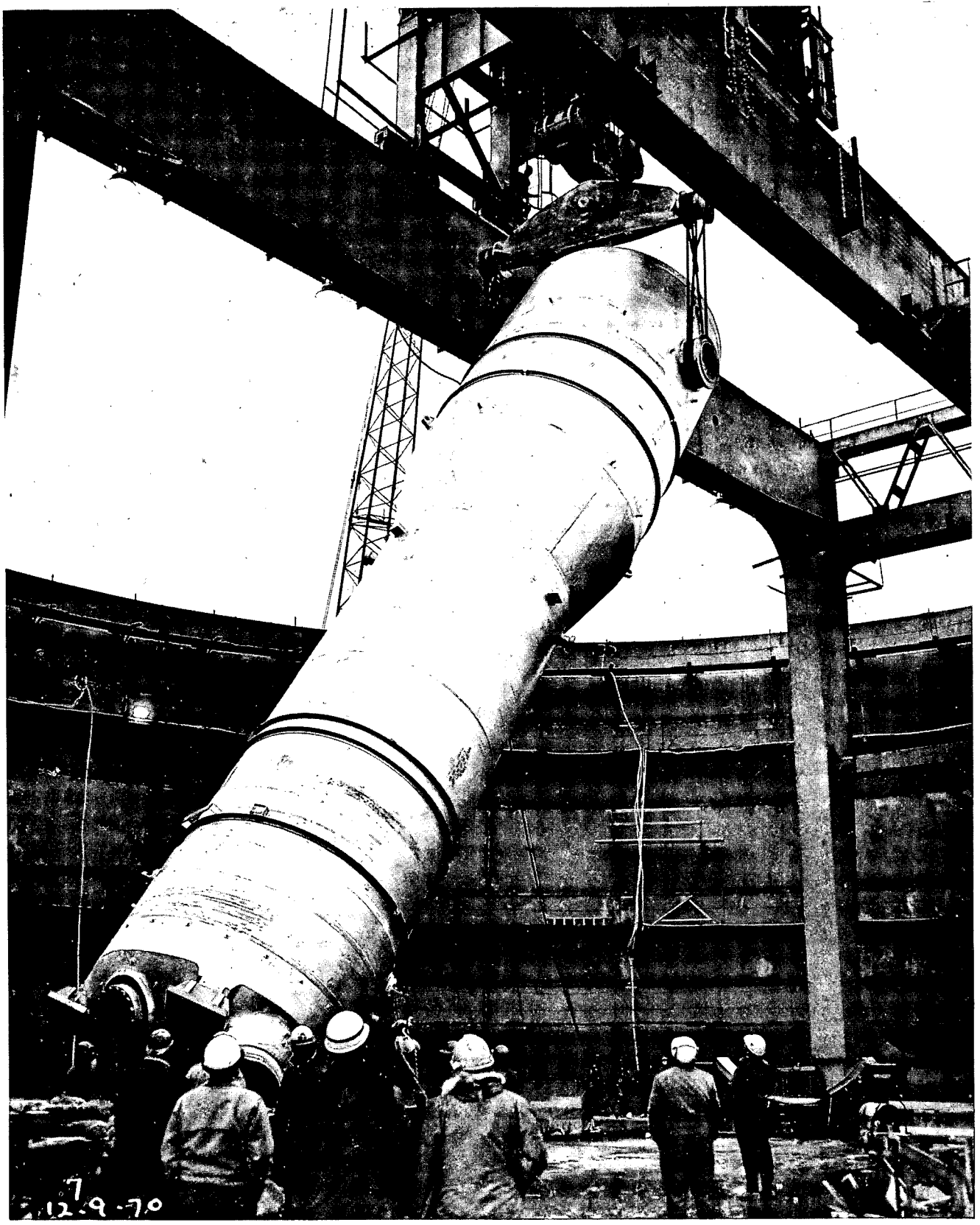

Figure - 36 Steam generator being lifted into position to be set

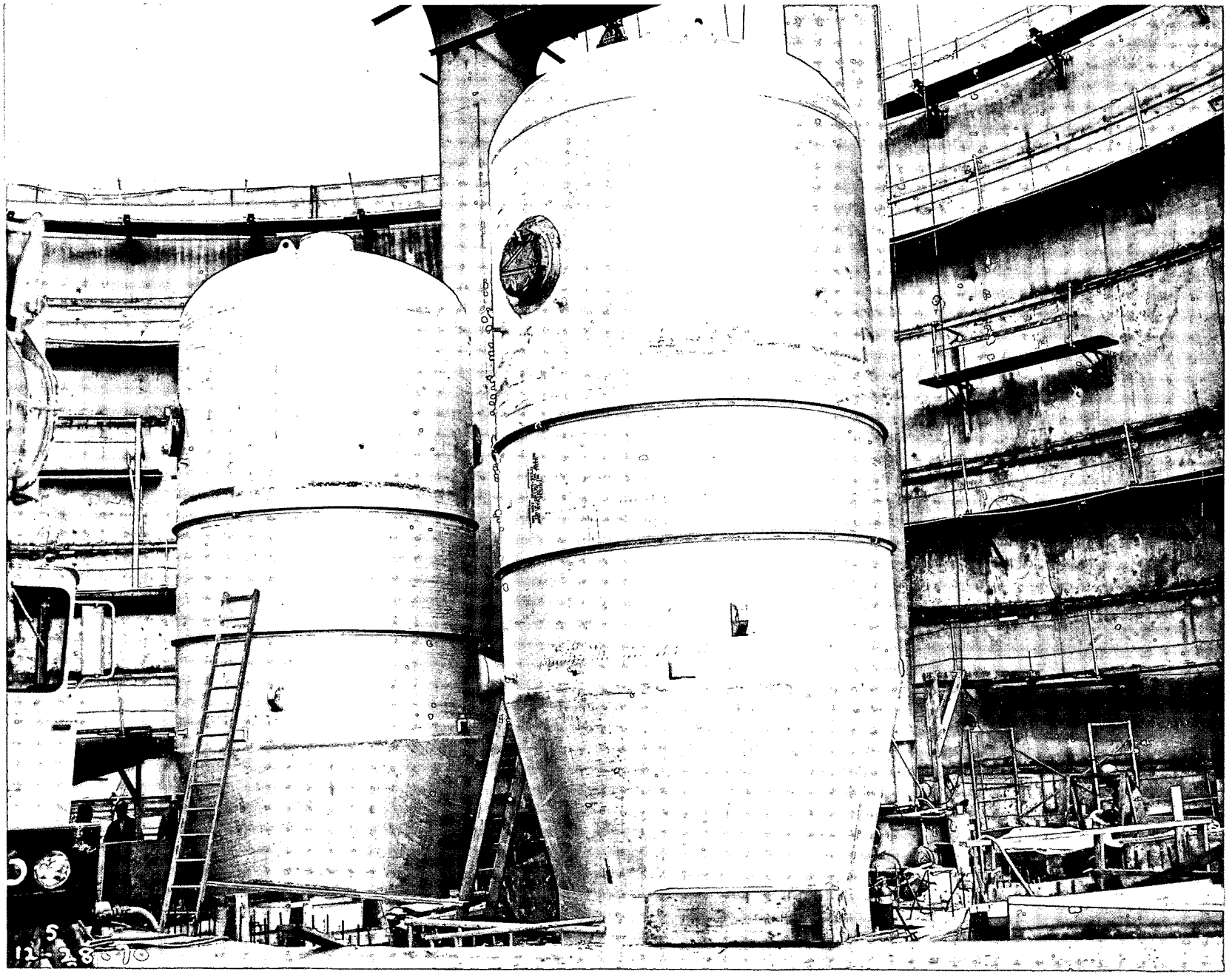

Figure - 37 Steam generators No. 33 and No. 34 set in place

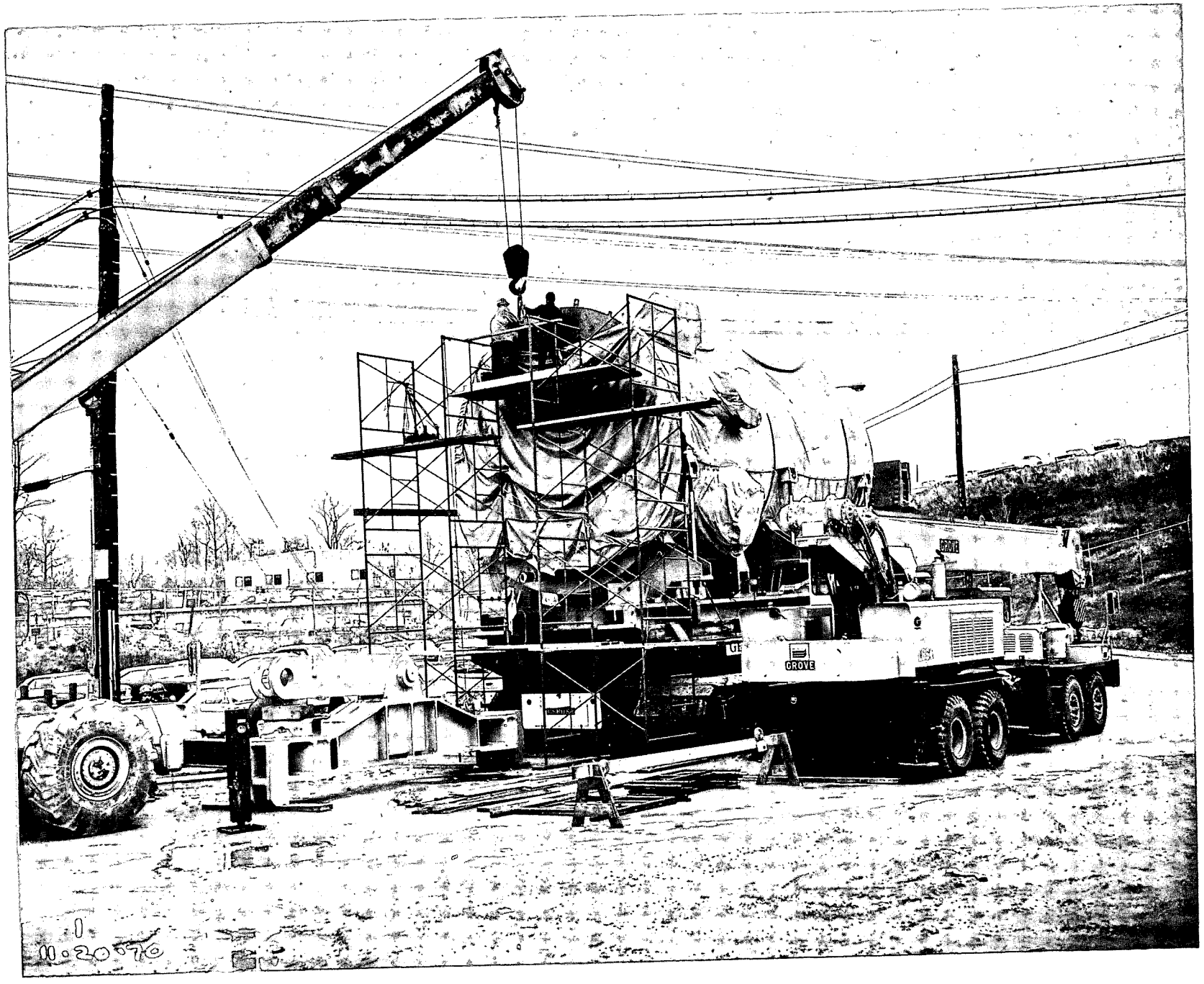

Figure - 38 Reactor vessel at foot of the temporary road where preparations are being made to attach lifting rig

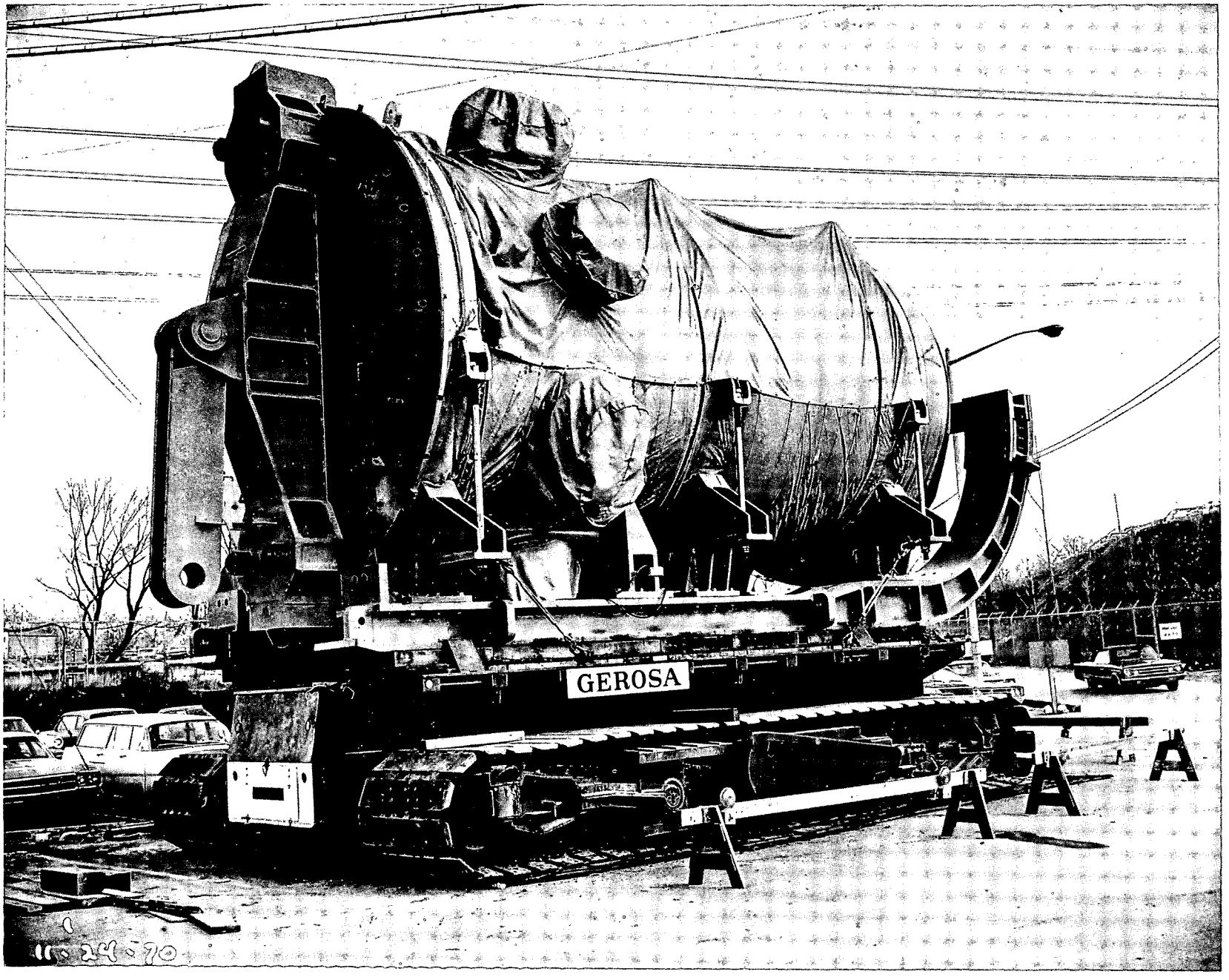

Figure - 39 Reactor vessel with the lifting rig attached

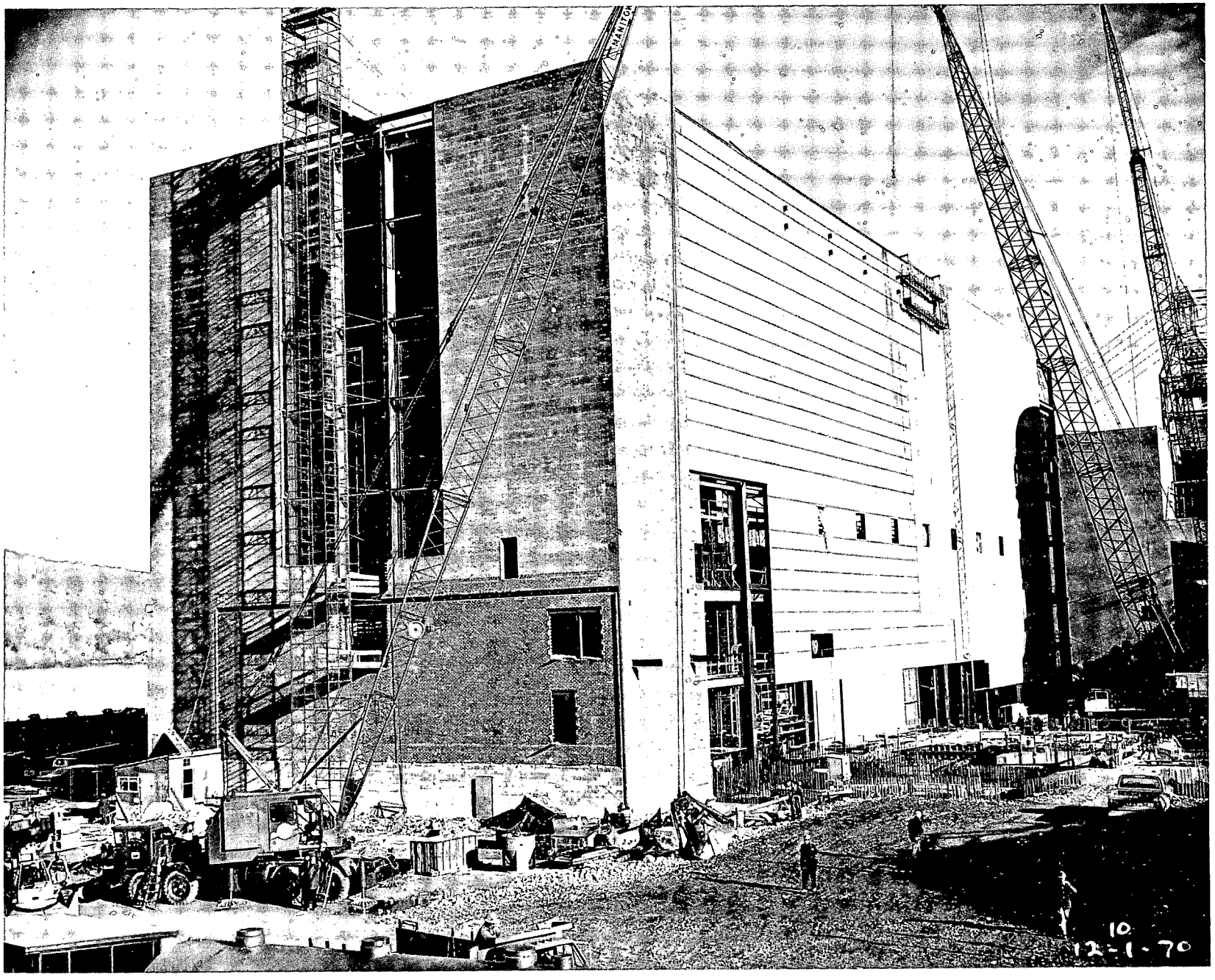

Figure - 40 View of brickwork and siding on the Turbine Generator Building

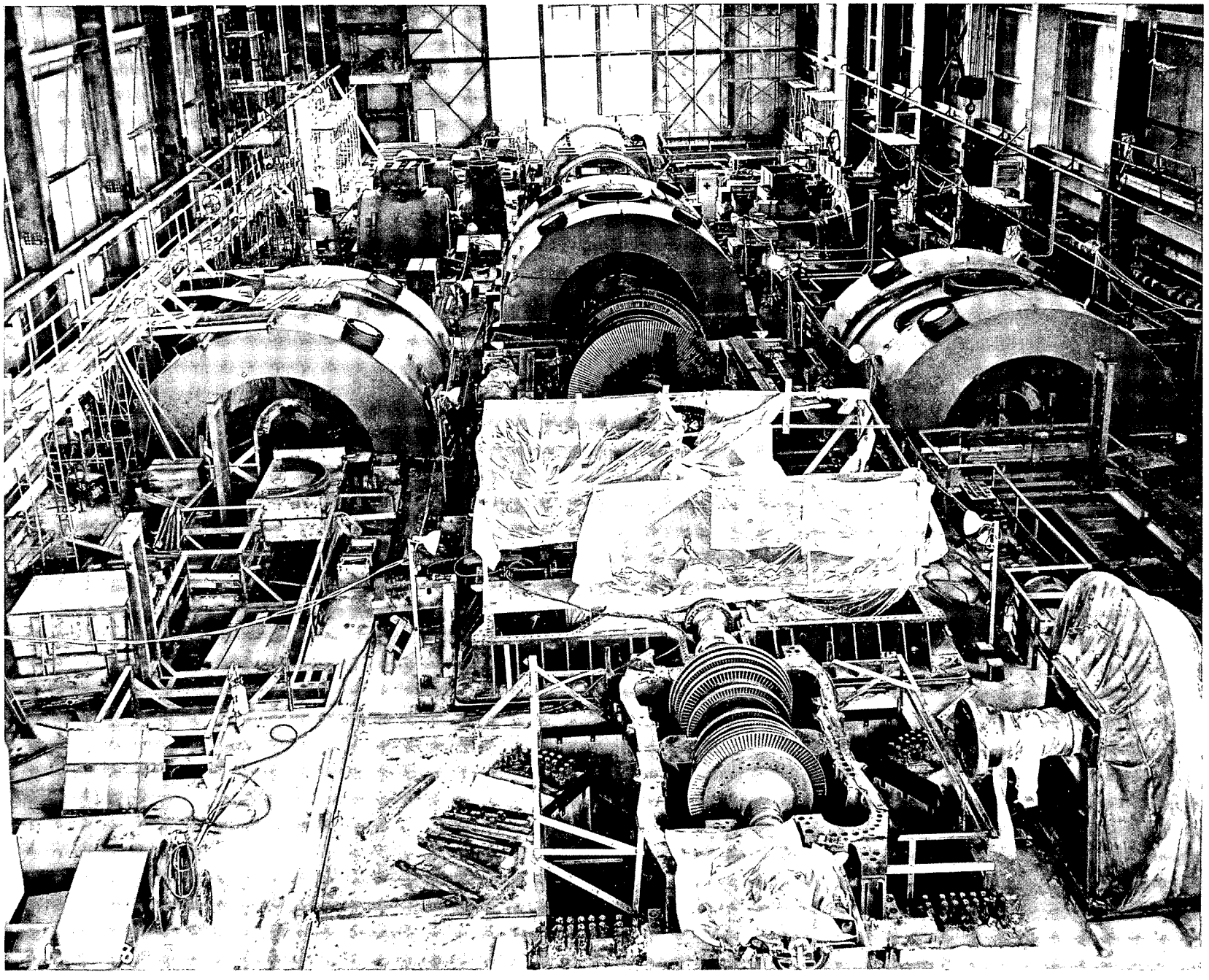

Figure - 41 View looking south of main generator floor

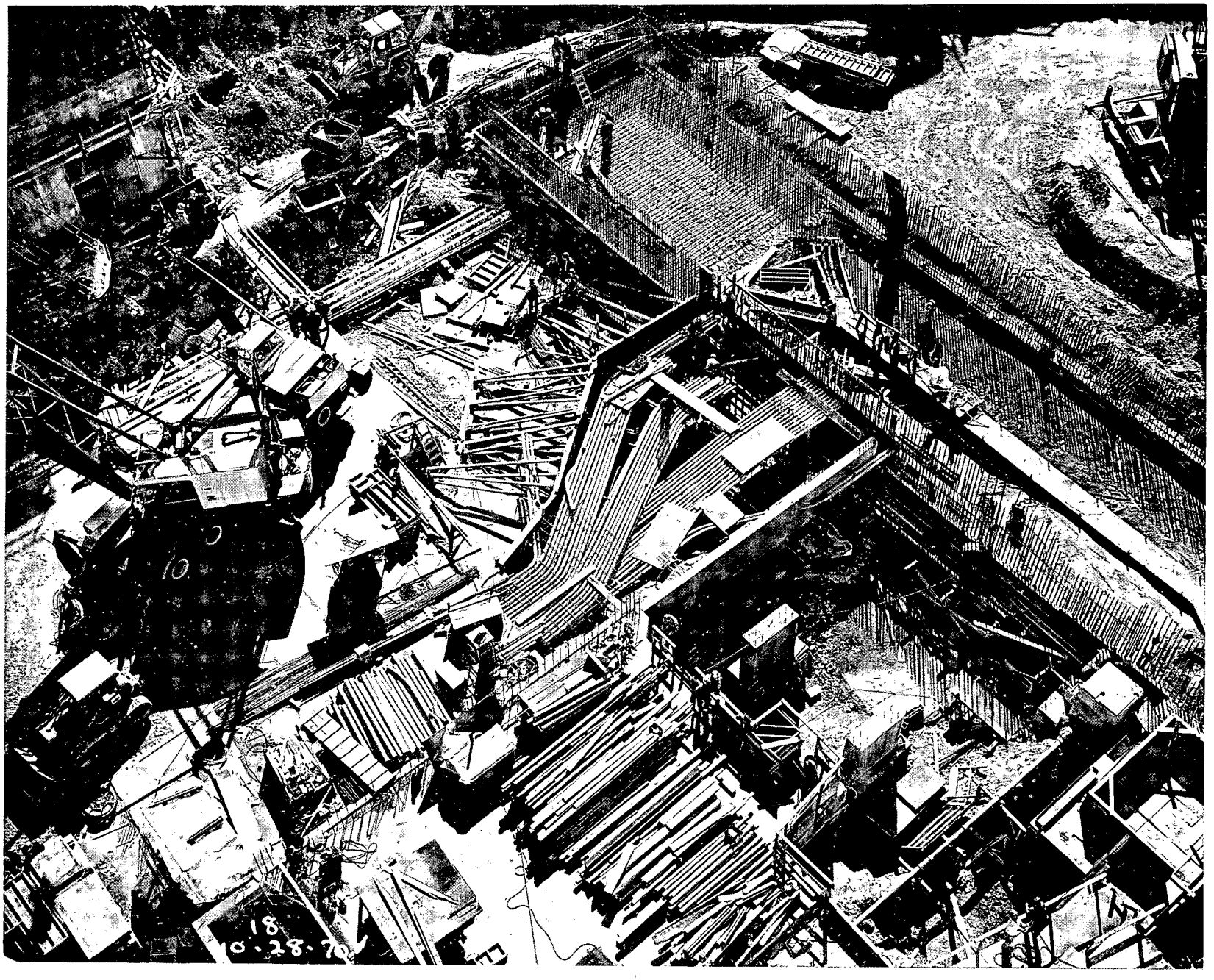

Figure - 42 Conduit piping in the transformer yards leading into the Control Building area

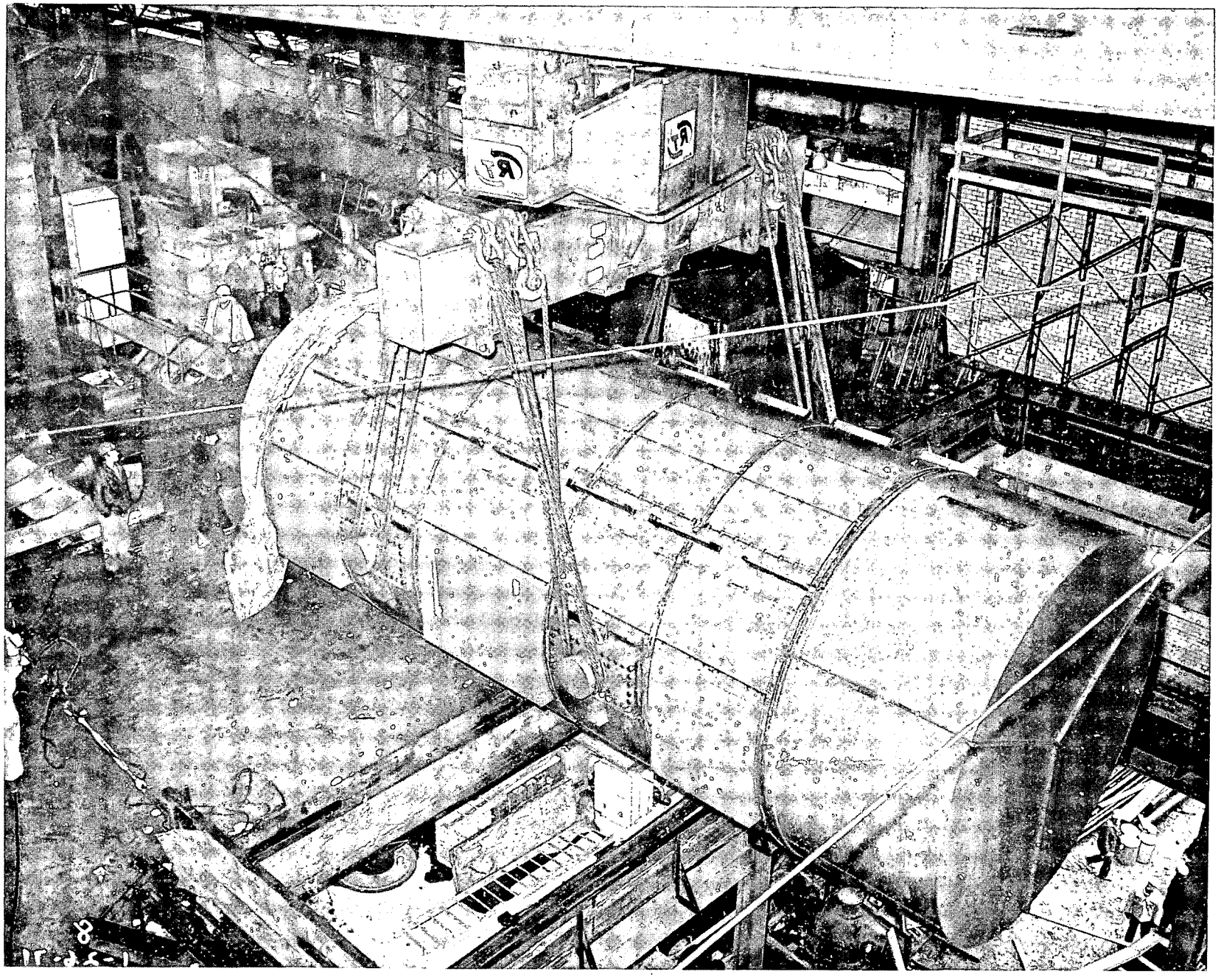

Figure - 43 Stator at main turbine generator floor level ready to be set in place

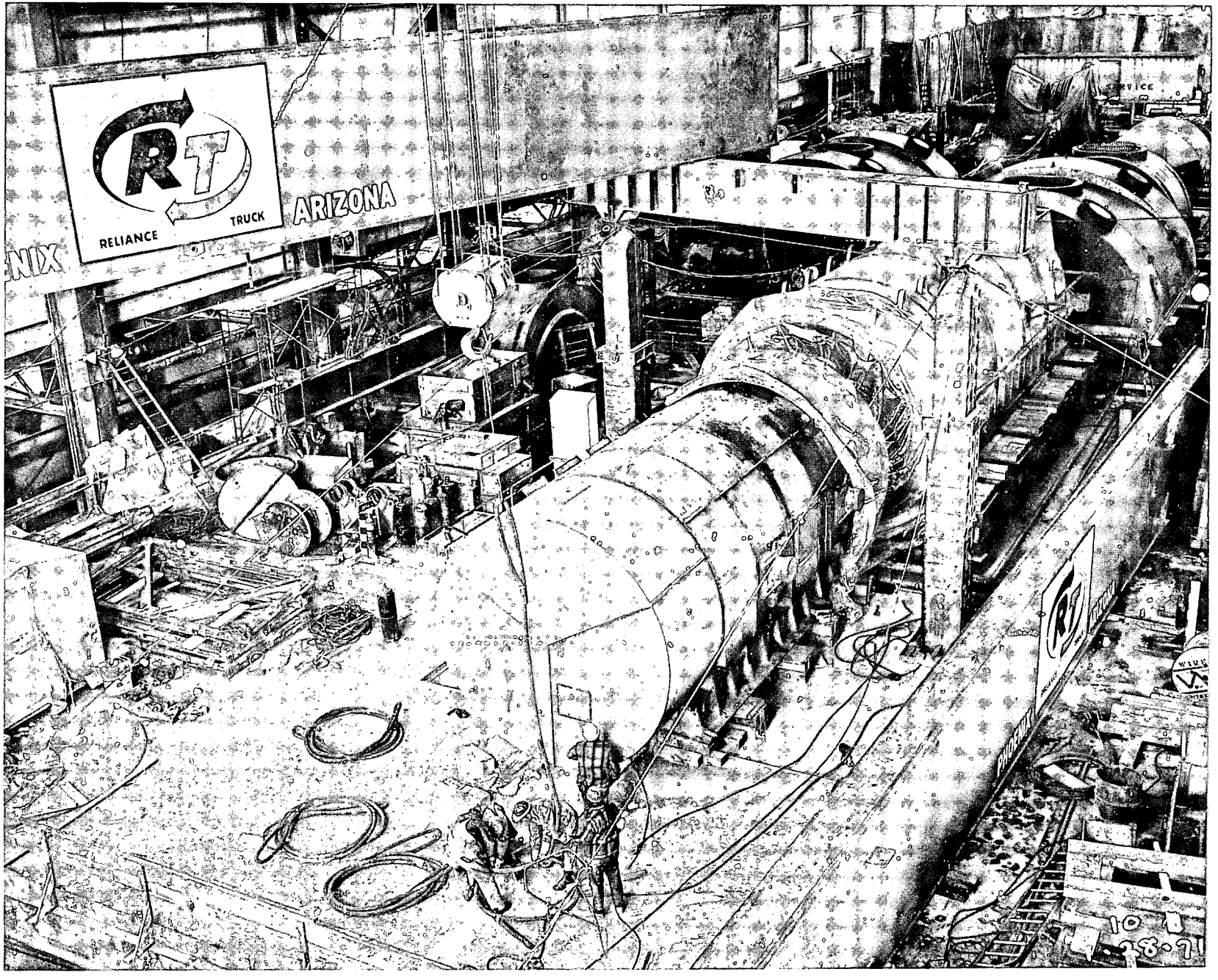

Figure - 44 Stator in place on the main turbine generator floor

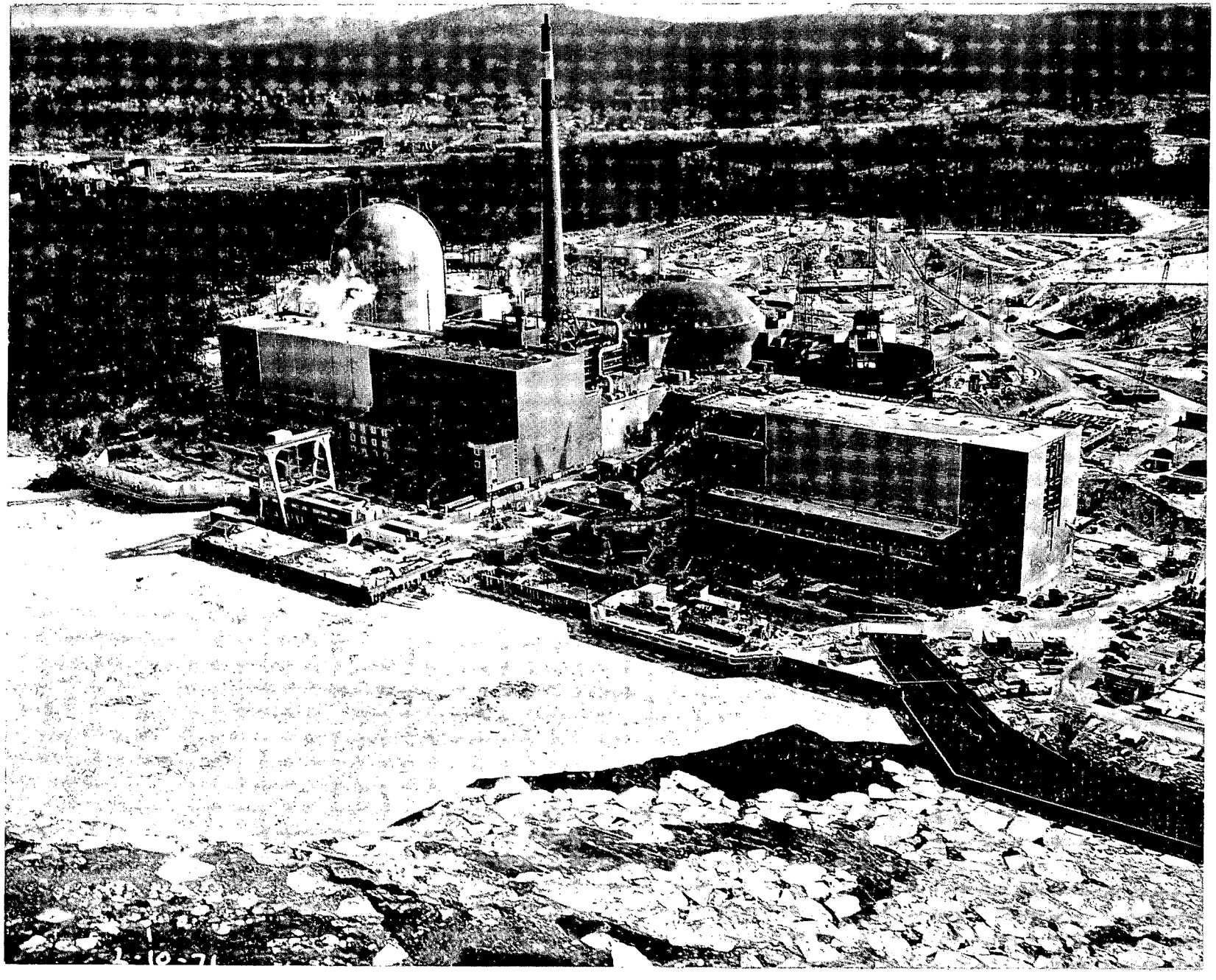

Figure - 45 Aeriel photograph - Displays the overall site construction as of January 1971

In order to reach the point where the plant is ready for its initial reactor coolant system hydrostatic test, several key operations must be performed such as setting of the reactor vessel, installation of reactor coolant pumps, pressurizer installation, installation of all piping within containment, and the eventual closing up of the containment building. Similarly, in other areas, equipment must be installed and its associated piping and electrical work performed.

15.2 Impact of Construction Activities

At the Indian Point site today, within the confines of a limited cleared area, there exists the construction site for a nuclear complex with laydown areas, parking lots for workers' cars, construction buildings, an array of heavy equipment and all the activity normally associated with large scale construction. While the temporary environmental impact of such change and activity cannot be termed desirable, the work has been planned and controlled so as to localize any effects.

The main boundaries of the site have been left relatively untouched in an attempt to provide a visual and acoustic shield for the surrounding neighborhood. As construction approaches completion, and work forces and equipment on the site diminish, orderly restoration will begin to accelerate. Complete restoration of the site is expected to be accomplished within one year of the completion of Unit No. 3. At that time a new park with industry hosting recreational, educational and cultural facilities will have replaced an abandoned amenity from another era. Plans for the park are discussed later in this report.

While some minor relocation of wildlife has occurred as a result of construction, approximately one-half of the site peripheral to the construction area remains untouched and provides an immediate refuge. This has held to a minimum the actual distance of wildlife relocation. When the areas disturbed during construction have been restored, rapid wildlife resettlement can be expected. Combustion products released to the atmosphere during construction as a result of the operation of diesel-powered equipment are of the type associated with any large-scale construction job. Dredging and filling generally result in the destruction of benthic organisms in the area involved. Since relatively little dredging and filling were required for the construction of the Unit No. 3 intake and discharge structures, effects of this type were minimal.

16.0 AESTHETICS

It should be emphasized that use of the site during construction was planned, and every attempt was made to restrict clearing and damage. This care has reduced considerably the disturbance inflicted on the natural state of the site during construction and will both simplify and accelerate restoration.

When they are completed, Unit No. 3, the restoration of the construction site, the visitors' facility and the landscaping that is planned will constitute an aesthetically acceptable solution for the site consistent with the multiple uses to which it will be devoted. While the main emphasis will be on the use of nuclear energy to generate electricity, the combination of form, mass, scale, color and texture as related to the topographic and natural quality of the setting will represent a new concept in industrial and civic planning. As may be seen by Figure - 46, which is an artist's rendition of the completed Indian Point complex as seen from the west bank of the Hudson River, complete aesthetic harmony will be maintained.

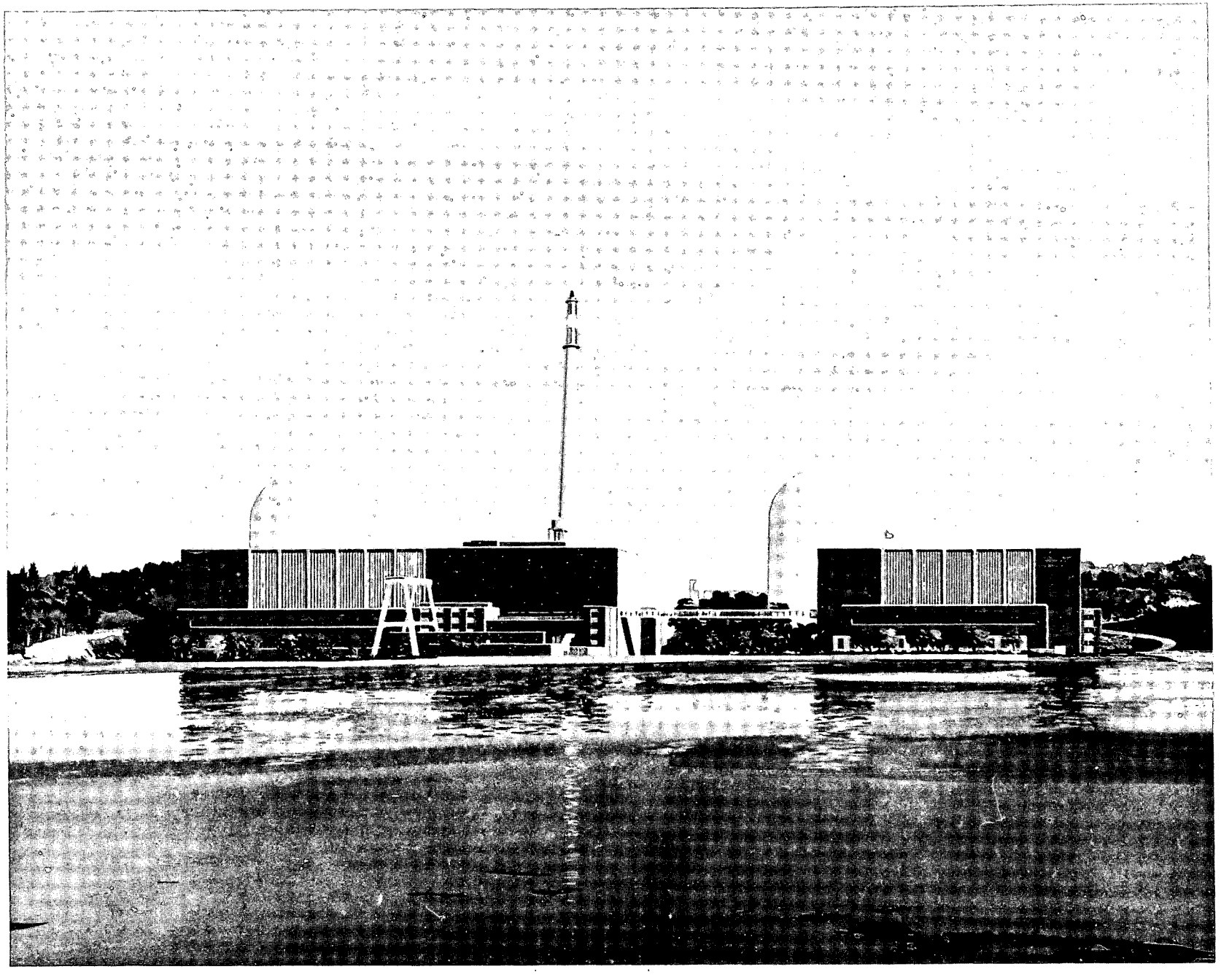

Figure - 46 Artist's rendition of the completed Indian Point complex

17.0 ALTERNATIVES

17.1 Alternative Sources of Power

Indian Point No. 3 is an integral part of Con Edison's long term generation program which has been developed to assure dependable and economical supply of electric power to the people of New York City and Westchester County. Therefore, not only will Indian Point Unit No. 3 be necessary to furnish power during the Summer of 1974, when it is scheduled for service, but also for many years thereafter. Accordingly, it is necessary to consider not only whether any acceptable alternatives to this Unit would be available in 1974, but also over the longer term, in the event the Unit were not granted an operating license.

In view of the fact that Indian Point No. 3 is approximately 70% complete as of September 1, 1972 this section will consider alternatives available in the context of the partially-constructed plant. There would appear to be no purpose in reviewing the decisions made several years ago which led to the commencement of construction of Indian Point No. 3.

(a) Alternatives for 1974

Construction of other new base load plants is not feasible to meet 1974 requirements. A new fossil-fueled plant would require an estimated 6 years of construction time to complete and an alternative nuclear power plant would require an even longer time. Additional time is required for pre-construction regulatory and public approvals, assuming an acceptable site is found.

Gas turbines which could be installed by 1974, are not technically alternatives for a base load plant such as Indian Point Unit No. 3. By 1974 Con Edison will have installed on its system about 2350 MW of gas turbines. Approximately 200 MW of this capacity was installed by the Company to serve as emergency start-up and transit capacity and 2100 MW to provide peak capacity for the early 1970's as compensation for delays already incurred in the Cornwall Pumped Storage plant and to replace capacity lost due to equipment deterioration at older plants which have been used for peaking purposes.

Peaking capacity supplied by these gas turbines is electricity furnished for a limited number of hours per year when demand for electricity is unusually high because of the seasonal increases in demand. This is encountered particularly during the summer for air conditioning, or because of short term outages of other generating units. Gas turbine capacity beyond that already planned for the system would be required to operate for more hours than would normally be the case for gas turbines intended solely for peaking capacity. The recent capacity shortage has forced Con Edison to operate its gas turbine capacity for more than double its intended operating hours. As a result of this experience continued operation at these high levels could cause serious equipment deterioration and reduced reliability.

Purchased power is likewise not a feasible alternative for Indian Point Unit No. 3 for the year 1974. Con Edison already has a commitment for 40 MW of purchased power for the summer of 1974 and is involved in various stages of negotiations to arrange the purchase of an additional 510 MW. These purchases have been included in the estimates of installed capacity and reserve which were discussed in the Need for Power Section and will be necessary even if Indian Point No. 3 is available. Should Indian Point Unit No. 3 be unavailable, the likelihood of purchasing additional capacity to replace the 965 MW capacity of that unit is remote. The availability of additional power for firm purchase will be in large part contingent upon the completion of new facilities which are scheduled for service through 1974. The generally prevailing experience of slippages in utility construction projects involving both generating stations and transmission facilities casts serious doubt on the availability of significant amounts of additional power. To the extent that construction or regulatory delays create capacity deficiencies among members of neighboring power pools, any excess capacity in such pools is likely to be sold preferentially to their deficient members, thereby reducing the amount of power which might otherwise be available to Con Edison.

Con Edison has in the past made emergency purchases of energy from outside the system. Such purchases and other short duration purchases will probably be available in varying quantities from day to day as load and system conditions of other utilities permit. However, there is no assurance as to the availability of such power, and it would be extremely imprudent to plan to meet load demands utilizing emergency purchases without any basis to predict when and how much will be available.

Some additional power might be available by deferring retirement of older stations. As noted in the Need for Power Section, much of this capacity was installed between forty and fifty-six years ago and was scheduled to be retired prior to 1970 as part of the Company's plans for the 3838 MW of new capacity that is now delayed (Indian Point Units Nos. 2 and 3 and the Cornwall Pumped Storage Project). These plants have become increasingly difficult to maintain and are no longer dependable. They will deteriorate further each additional year that they remain in service, despite continuing maintenance efforts. Accordingly, deferment of retirements would not produce a reliable source of power.

A failure to operate Indian Point No. 3 when available will produce an adverse environmental impact in that it will require the Company to make greater use of older fossil-fueled plants until such time as replacement capacity is available. To demonstrate, the Company has analyzed the dispatch of various groups of units which would occur during the first scheduled full year of operation of Indian Point No. 3, both with and without Indian Point No. 3 in service. Table 17-1 indicates the increased energy output and increased sulfur dioxide, nitrous oxides and particulate matter by station that would be emitted if Indian Point No. 3 were not in service as presently scheduled. The increase in the emission of pollutants is expected to be 486 tons per year of particulates, 9706 tons per year of sulfur dioxide and 11,811 tons per year of NO_x.

The economic cost of not operating the plant when available is estimated as approximately 6-1/4 million dollars per month, consisting of an estimated 4-1/2 million dollars as the incremental cost of replacement power and approximately two million dollars per month as the carrying cost of the idle investment.

(b) Long Term Alternatives

As discussed in the Need for Power Section, all experience to date shows an increasing demand for power which Con Edison is legally required to meet. In addition to its construction of Indian Point Nos. 2 and 3, Con Edison is participating in the construction of four fossil-fueled generating units on sites along the Hudson River at Bowline Point and Roseton. Bowline Point No. 1 is scheduled to be in service by late summer of 1972. Roseton Nos. 1 and 2 are scheduled for service prior to the summer of 1973, and Bowline Point No. 2 is scheduled for the Spring of 1975.

TABLE — 17-1

INCREASED GENERATION AND STACK EMISSIONS AT CON EDISON GENERATING STATIONS AS A RESULT OF INDIAN POINT UNIT NO. 3 NOT IN SERVICE FROM JUNE 1974 TO MAY 1975

Station	INCREASED GENERATION (10^6 KWH)	Additional Emissions of Particulates (tons)	SO_2 (tons)	NO_x (tons)
Out of City				
Nuclear				
Indian Point (Units 1 and 2)	222	2	35	38
Fossil				
Bowline Point	335	25	505	552
Roseton	465	117	2332	764
Total Fossil	800	142	2837	1316
Total Out of City	1022	144	2872	1354
In City				
Hudson Avenue	203	31	615	672
Waterside	93	13	250	273
74th Street	47	6	122	133
59th Street	-	-	-	-
Astoria	1279	106	2127	2322
Ravenswood	971	76	1526	1666
Arthur Kill	423	36	728	795
East River	289	26	524	572
Gas Turbines	1020	48	942	4024
Total in City	4325	342	6834	10457
TOTAL SYSTEM	5347	486	9706	11811

NOTE: Assumes 0.3 % sulphur oil for all stations except Roseton, which is 1.0% sulfur oil and gas turbines which are a combination of kerosene (0.05%) and No. 2 Oil (0.2%). Emissions on nuclear units are from Indian Point No. 1 superheater.

Even with these additions, there will remain a need for additional capacity resources. Both the Federal Power Commission and the New York State Public Service Commission have stated that even with the planned additions through 1973, including Indian Point No. 3, there will be an urgent need in 1974 for an additional base load fossil-fueled unit that Con Edison has proposed to build in New York City, at its Astoria plant. Thus, if Con Edison were not to receive an operating license for Indian Point No. 3, it would be necessary to replace the unit with other new resources.

In order to replace Indian Point No. 3 with a new unit, another site has to be found. Con Edison is faced with an extreme shortage of available sites to meet projected load growth even with Indian Point Nos. 2 and 3 in service. In order to obtain permission to construct a new fossil-fueled unit at its Astoria plant, the company entered into a Memorandum of Understanding with the City of New York in which it was agreed that no more fossil fueled boilers for electric generating plants will be located on the New York City mainland. Any use of an alternative site as a replacement for Indian Point No. 3 at a time when sites are scarce would jeopardize Con Edison's ability to obtain sites for future plants needed to meet load growth and to replace obsolete units. It must be noted that if it were necessary to replace Indian Point No. 3, the power supply problems described in the Need for Power Section would continue until completion of the replacement unit.

Gas turbines, as previously discussed, are not a feasible alternative to supply base power. Furthermore, as will be discussed below, they would be a costly alternative.

Con Edison hopes to commence purchasing 800 MW of power in 1977, from Hydro Quebec. The transaction with Hydro Quebec will involve a straight purchase through 1981. Thereafter a seasonal exchange may result. A letter of intent has been executed by both parties. An appropriate export license will be required from the National Energy Board of Canada; and such a license is available only if the power to be exported does not exceed what is needed to meet "the reasonably foreseeable requirements for use in Canada."

In 1978 Con Edison hopes to commence purchase of 500 MW from the Breakabeen Pumped Storage Project of the Power Authority of the State of New York. The Federal Power Commission has not yet licensed this project and it is therefore only a possible source of

power. Assuming these purchases are made, they will be necessary to meet the load growth of Con Edison even with Indian Point No. 3 in operation and are not available as a replacement for Indian Point No. 3.

Con Edison has investigated other possible sources of generating capacity such as the planned Canadian hydroelectric development at Churchill Falls in Labrador. Inquiry in this regard determined that essentially the entire output of the Churchill Falls plant would be required for anticipated load growth in Canada. Despite recent plans announced for major expansion of the Canadian hydro resources in the early 1980's there have been no indications to Con Edison that such resources will be available for sale to the Company. It cannot be assumed that any significant amounts of power from these sources will be available.

A discussion of the alternatives for Indian Point No. 3 must start with the fact that the plant is already under construction and is scheduled to serve the needs of Con Edison's customers by 1974. The benefits are its near term availability to fulfill the need for power, its utilization of a scarce plant site and, as noted above, a reduction of emissions of air pollutants particularly in New York City. As of August 1972, Con Edison will have expended on Indian Point No. 3 approximately $144,335,000 and is committed to pay for the balance of the construction of the plant, leading to a full cost of approximately $317,236,000. If the plant were abandoned, there would be additional costs of permanently closing the facility, re-training of personnel, etc.

A nuclear plant at another site to replace Indian Point No. 3 would preempt a scarce site needed to serve future load growth and would lead to a shortage of power during the time required for its construction which we do not believe would be completed within this decade. Such a plant would cost considerably more than Indian Point No. 3, perhaps two to three times as much.

A fossil-fueled alternative to Indian Point No. 3 would similarly preempt a scarce site needed to serve future load growth and would lead to a shortage of power during the time required for its construction. Such a plant would also encounter environmental objections, primarily based on air pollution. Fuel costs of a fossil plant would be considerably greater than that of a nuclear plant, particularly if very low sulfur fuels are required, and by the

time that such a plant could be built its capital costs would likely exceed those for Indian Point No. 3. It is estimated that costs for a fossil fueled plant that would produce the same capacity and energy as Indian Point No. 3 would be about 18.5 mills per Kwhr, excluding transmission, as compared to 9.4 mills per Kwhr for Indian Point No. 3, in the earliest year the fossil plant could be installed.

The alternative of gas turbines could be available within a shorter period of time than is required for a nuclear or fossil plant. As noted above, the use of gas turbines for base load operation would present unusual problems. This would also be a very expensive alternative. Although gas turbines would have a lower capital cost (estimated to be about $145 per kilowatt excluding transmission) than Indian Point No. 3 (which it is now estimated will cost, when completed, $328 per kilowatt for 965 MW excluding transmission), they would have a much higher production cost (about 16.0 mills per kilowatt hour in 1974 as compared to approximately 2.5 mills per kilowatt hour for Indian Point No. 3 for the first full year of operation).

By August 1972, Con Edison will already have invested $144,335,000 in the construction of Indian Point Unit No. 3. Thus, the alternative of installing gas turbines to provide capacity in place of Indian Point Unit No. 3 and to produce energy for Con Edison customers as part of the total mix of system capacity resources must be compared to the cost to complete Indian Point Unit No. 3 and to provide energy with that unit in service. As a result of the significantly higher fuel costs, total system annual costs will be greater if a gas turbine alternative were installed in place of Indian Point Unit No. 3. The total additional annual cost to install gas turbines, rather than complete Indian Point Unit No. 3, and to produce energy from units with higher fuel costs than Indian Point Unit No. 3, would be approximately $49 million.

The cost of purchased power as a long term alternative to Indian Point No. 3, if such power were available, would be considerably greater than producing equivalent power at Indian Point. The cost of this power varies greatly depending on its source, transmission distance, etc.

The costs for the purchase of firm power are established by negotiations with the seller. In 1970 the cost of firm purchases averaged 8.3 mills per kilowatt hour. During the summer of 1971, in which 920 MW of firm power was purchased, the average cost was 11.1 mills per killowatt hour. Individual purchases ranged from 8.0 to 19.5 mills per kilowatt hour. Costs of power in the future are expected to be greater because they would be based on new plant costs. For example in 1972, Con Edison has contracts for 978 MW of firm purchase with an average cost of 10.4 mills per kilowatt-hour. Individual purchases range from 9.1 to 22.8 mills per kilowatt-hour. By comparison, the cost to generate power at Indian Point No. 3 is expected to be about 9.0 mills per kilowatt hour, for the first full year. This includes the capital cost already expended on Indian Point No. 3. If only the additional capital remaining to be expended is included, the cost to generate power at Indian Point No. 3 is about 6.0 mills per kilowatt hour.

Supplemental and emergency purchase of power may be expected to be available for short periods and in varying quantities in the future. However, both forms of purchased power are intended to be of short duration and are available only when the seller's system has capacity in excess of its own requirements. Supplemental power may be scheduled in advance of use where it is known a deficiency will exist. It is usually made available at the seller's cost (which includes start-up and operating charges and fuel and incremental maintenance costs on the seller's highest cost equipment) plus 10% or $20 per MW/day and 5 mills, whichever is greater. Emergency purchases are those which are not prescheduled, but rather are requested at the time of an emergency when a company's load carrying capability is in jeopardy. The purchase price for emergency purchase is seller's cost plus 10%. From June 1, 1971 to September 30, 1971, the average cost of supplemental and emergency purchases was 15.7 mills per kilowatt hour. In 1970, the average cost of supplemental and emergency purchases experienced by Con Edison was 11.5 mills per kilowatt hour. This is already considerably higher than the cost of power from Indian Point Unit No. 3 and as demonstrated by the costs in 1970 and 1971 it may be expected that these costs will increase in the future.

Con Edison does not believe there is any basis for not licensing Indian Point No. 3 and for replacing it with one of the alternatives discussed. The overriding consideration in

in Con Edison's view is that the time required to install an acceptable base load alternative to Indian Point No. 3, if one can be installed, would be of such duration as to extend the current power supply crisis in New York City and Westchester throughout the remainder of this decade. The failure to license Indian Point No. 3 would also involve the loss of $317,236,000 which is to be expended on the Plant and the additional cost of the construction of an alternative plant. The long-term environmental costs of operation of Indian Point No. 3 are minimal, and are more than off-set by the benefit of reduced air pollution in the New York City area which will result from operation of this Unit. Hence, avoidance of the minimal environmental costs does not justify rejection of the environmental benefit to be obtained from operation of Indian Point No. 3 or incurring the great economic loss from the abandonment of that Unit.

17.2 Alternative Fish Protection Measures

The Consolidated Edison Company has considered various new intake structures, modifications of the existing intake structures and other fish protection alternatives at the Indian Point Station. A brief description of these measures follows.

(a) Air Bubble Curtain

An air bubble curtain of a modified design was tested at Indian Point Unit 1 during February 1971 and proved effective at reducing the number of fish impinged in the test bay. Based on that test a complete air bubble curtain is being installed at the intakes of Units 1 and 2. The air curtains being installed are an improved design over the device found unsatisfactory in April 1963. The cost of a permanent installation for Units 1 and 2 will be approximately $1,700,000.

(b) Habitat Alteration

Early this year, a hole in the river bottom directly in front of the intake at Unit 3 was filled in an effort to eliminate a desirable fish habitat close to the intake structure.

(c) Common Intake Structure

As described in Section 9.1, Condenser Cooling Water System, (see also Figure 18) Con Edison is considering a new intake screen structure for the Indian Point generating units. Engineering design and hydraulic modeling of this project are underway.

This concept consists of a common intake structure built farther out in the river with a single row of vertical traveling screens parallel to the river flow. This structure would screen water for all three units at Indian Point and would be designed to permit intake velocities below 0.3 feet per second during the colder parts of the year and 0.5 feet per second in the summer. The traveling screens will also deny access under the wharf to the fish, thereby eliminating the possibility that the wharf is acting as an attraction mechanism. The effectiveness of this structure will depend on low intake velocity and washing of the front of the screens by river's stronger currents.

The estimated cost of the new intake is $12-$15 million.

(d) Horizontal Traveling Screens Straight Line in the River

This is similar to item (c) except horizontal traveling screens replace the vertical traveling screens. As the name implies, screen panels on the horizontal traveling screen move in a horizontal fashion thus pushing the debris and fish to the side within the water column rather than lifting it out of the water as in the vertical traveling screen. The horizontal traveling screen is still in the developmental stage and has not been commercially demonstrated.

The cost of this structure would greatly exceed $11,500,000 and would, of course, have to include costs for development and testing.

(e) Vertical Traveling Screens W Shape with By-pass in the River

This is similar to item (c) with the vertical traveling screens placed in two or three V shaped arrangements with by-passes and fish pumps for removing fish. When the screens are placed at an angle in the flow, a unidirectional flow pattern is established immediately in front of the screen. The velocity component through the intake screen can be increased to 1-1/2 feet per second. The velocity component in the by-pass is 1.4 times the component through the screen and carries the fish into the by-pass. The fish are then returned to the river either by pumping or lifting from the by-pass water. By-passes have been successfully used without pumps or lifts on free flowing streams on the west coast especially for the migratory species of fish. Their application to an estuarine body requires pumps to maintain

flow in the by-pass. Fish mortality in fish pumps can be expected to range from 5 to 50% based on limited testing made to date.

The cost of such and intake structure would be approximately $14,600,000.

(f) Relocation of Vertical Traveling Screens at the Front of the Forebays at Units 1 and 2

Since the vertical traveling screens are recessed inside the forebay at Unit 1, a situation is created where small fish entering the forebay lose the freedom of lateral movement and ultimately impinge on the screen. To rectify the situation fixed screens have been placed out front which require frequent cleaning and added manpower. The vertical traveling screen can be placed at the front of the forebay where the fish will be free to move laterally in front of the screen to avoid impingement. If the screens were to run continuously, an impinged fish could be washed off the screen with practically no delay thereby reducing the mortality rate of impinged fish. Vertical traveling screens at Unit 3 are located at the front of inlet bays.

The cost of such a relocation of the vertical traveling screens will be approximately $1,000,000 for Unit 2. It will be higher for Unit 1 because of the existing wharf.

(g) Vertical Traveling Fish Basket

A vertical traveling fish basket installed in front of the fixed or vertically traveling screens to scoop fish from in front of the screens has been proposed as a measure for fish protection at Indian Point. The basket, still under development, is reported to be effective in simulated experimental runs with salmon and trout conducted by the National Marine Fisheries Service at Seattle. Con Edison expects to install and test the device at Indian Point. The practicability and effectiveness of such a facility for Indian Point has yet to be demonstrated.

Con Edison has employed consultants to determine whether other possible alternatives were used by other utilities in this country and in England, and that study has not revealed any promising alternative procedure. Con Edison has not rejected any alternative because of cost.

The alternative of shutting down the plant in event of fish impingement problems requires a balancing of competing factors. As discussed in Section 17.1, a shutdown of the plant would produce a serious power shortage and increased emissions of air pollutants on New York City. If, for purposes of analysis, the power shortage problem can be ignored, there is an environmental trade-off between air pollution in New York City and fish protection at Indian Point. It is necessary to compare the known problems of air pollution and the known risk of damage to the fish population, which damage, if any, is not irreversible. In balancing these problems, Con Edison is influenced by the fact that the best judgement of its consulting experts based on present available information is that the fish problems have not had any significant detrimental effect on the Hudson River Fishery in the area of the plant, and any effect they might have had is not irreversible. This is confirmed by the evidence of the continuing abundant fish life in the vicinity of Indian Point. The public interest favors solving the known problems of air pollution and power shortage while continuing to search for the best possible solution to the fish protection problem.

17.3 Alternate Cooling Methods

17.3.1 Indian Point Unit No. 3 Cooling Water System

The cooling water system designed and constructed for Indian Point No. 3 is termed a once-through system. Water is screened to remove debris, pumped directly through tubes in the condensers where it cools the turbine exhaust steam until the steam condenses, and is then returned to the river through a discharge structure designed to create mixing with sufficient additional river water so as to satisfy applicable water quality criteria of the State of New York.

The Indian Point Unit No. 3 turbine operates on steam, a portion of which is extracted from the turbine for reheating of the condensate that is reused in steam generators. The remainder of the steam expands in the turbine performing work to drive the generator. When all useful work has been taken from the steam, there still remains a considerable quantity of energy that must be rejected to a heat sink. The Indian Point Unit No. 3 heat sink consists of three 306,000 square foot condensers, each cooled by up to 280,000 gpm of Hudson River water. The temperature rise of the condenser cooling water is 16.3°F with a turbine generator output of 965 MW(e). The total heat rejection by the condensers is 6.84×10^9 Btu per hour.

In addition, 30,000 gpm of Hudson River water is used as service water to cool auxiliary equipment. The design temperature rise of the service water is 7.3°F. Heat associated with steam generator blowdown is negligible. The total heat rejected to service water is 0.11×10^9 Btu/hr and the total temperature rise (service water + condenser cooling) is 16.0°F.

17.3.2 Description of Alternative Cooling Systems

(a) General

"Alternative cooling systems", as defined in this section, are cooling methods other than the existing Indian Point Unit 3 once through system. These include dry and wet (evaporative) cooling towers of both mechanical draft and natural draft types, natural cooling ponds, spray ponds with powered spray module (PSM) fixtures, and other special types.

This section presents a brief description of each cooling system.

(b) Closed and Open-Cycle Systems

The alternative cooling systems described herein can be operated on either closed or open-cycle. In closed-cycle operation, condenser outlet water flows through a cooling tower or pond and is then re-circulated to the condenser inlet. In open-cycle operation, condenser circulating water, after being cooled by towers or ponds, is returned to a river.

The closed-cycle arrangement offers minimum thermal emission to river and minimizes the potential for fish impingement problems associated with large condenser circulating water flows. The disadvantages of closed-cycle operation include a degradation of turbine performance and heat rate because of high turbine backpressure; and less dilution for chemical and radioactive wastes. In addition, closed-cycle cooling alternatives introduce other environmental impacts such as fogging, drift and salt deposition, which may not be severe, but would be new and unnecessary for the Indian Point community.

In an open-cycle system, river water is pumped to the cooling element, cooled, and returned to the river. The water is returned to the river at a temperature higher than the river water temperature. Approximately 60% of the heat absorbed in the condenser by the circulating water is rejected to the atmosphere. The remaining 40% is discharged to the river (see page 17-47). In addition, since large amounts of cooling water are still required from the river, the fish impingement problem associated with the once-through cooling system is not reduced. For these reasons, closed-cycle cooling alternatives are considered preferable to open-cycle cooling alternatives.

(c) Dry Cooling Towers

Dry cooling towers are similar in operation to automobile radiators (See Figure 17-1). Condenser circulating water is pumped through finned tube heat exchangers where atmospheric air absorbs and carries away heat without directly contacting the circulating water. The flow of air can be promoted by fans as in the mechanical induced-draft design or by the natural draft principle as in the hyperbolic tower design. In the latter, the temperature difference between atmospheric air and the exhaust air within the hyperbolic shell creates a density difference which induces air flow through the tower.

In contrast with the wet cooling tower which uses evaporation as the principal method of heat transfer, the dry cooling tower has no evaporation from its system. The environmental impact of dry systems do not, therefore, include such conditions as fogging, drift, salt deposition, and thermal additions to river water. Also, blowdown and make-up water volumes are small and have practically no environmental effect. On the other hand, since heat transfer in dry cooling towers is entirely dependent on convection, much larger heat transfer areas are required. Most significantly, ambient dry bulb temperature is theroetically the lowest temperature to which the condenser coolant can be cooled. This would often result in turbine exhaust pressures in excess of 6 inches Hg, a condition that would be incompatible with the existing Indian Point 3 turbine-generator, which has a maximum limit of 5 inches Hg backpressure for continuous operation. The loss of turbine capacity at these high backpressures, together with high capital, fuel and maintenance costs, make dry cooling tower alternatives uneconomical.

The petro-chemical industry has utilized air blast cooling units for dissipating waste heat. However, these air exchangers are used usually to cool fluids with temperatures up to 150°F, which is at least 30°F higher than the Indian Point Unit No. 3 condenser coolant exit temperature.

In order to obtain condenser coolant exit temperatures necessary for dry-cooling tower operation, the present condenser must be retubed for multi-pass operation. The resulting high turbine exhaust pressure may not cause severe structural problems on the existing turbine and condenser; however, it would impose operational restrictions on the existing turbine, which has a maximum limit of five inches Hg backpressure for continuous operation. (For example, a 150°F condenser water exit temperature would produce 160°F turbine exhaust steam which results in 9.5 inches of Hg turbine backpressure).

Had the installation of Indian Point been designed initially for dry towers, the additional cost to the project would have been about $72 million. Dry towers are not a feasible alternative to the existing cooling system because the turbine generator plant is not designed to operate with exhaust steam at the elevated temperatures. There would be significant operating costs caused by unit derating resulting from additional auxiliary power requirements and

thermo dynamic performance deterioration and added maintenance if dry cooling towers were incorporated into the existing turbine-condenser system.

(d) Wet Evaporative Cooling Towers

As suggested by its name, heat transmission in a wet cooling tower is a combination of a sensible heat transfer between hot water droplets and ambient air, and from evaporation off the droplets. This process is achieved by pumping the warm circulating water to a distribution system in the tower and allowing it to splash down in a cascade fashion through numerous layers of fill. Depending upon the elevations of the air louvers installed on the tower side, air can be introduced to the tower in a direction resulting in a counter current between air and water droplets (as in the "counterflow" tower, shown on Figure 17-2), or forming a cross flow pattern between water droplets and air (as in the "crossflow" tower, shown on Figure 17-3).

In principle, the counterflow tower is more efficient thermally because of its maximum use of air-water heat transfer time; however, the crossflow tower offers less resistance to air flow and consequently lower energy consumption for mechanical draft towers.

Wet cooling towers, as well as dry cooling towers, are classified into mechanical-draft and natural-draft (hyperbolic) types, according to the method of inducing the heat absorbing ambient air to flow through the towers. Natural-draft wet towers are shown on Figures 17-4 and 17-5, respectively, for counterflow and crossflow types.

Since evaporation takes place in wet cooling towers, such adverse environmental effects as fogging, drift, icing and blowdown disposal do occur. However, the high-level plume discharge of a natural-draft cooling tower lessers local fogging, drift and icing conditions.

The scenic impact of evaporative cooling towers must also be considered. Natural draft towers for Indian Point Unit No. 3 would consist of a single tower approximately 500 feet high and having a base diameter of 525 feet. Mechanical draft towers would consist of three banks of towers, each bank approximately 500 feet long, 70 feet wide and 60 feet high.

The thermodynamic properties of ambient air are important to the successful operation of a natural-draft cooling tower. The density difference, or driving force to induce air inflow, decreases with higher ambient wet bulb temperatures and increases with greater relative humidity*. Therefore, the hyperbolic cooling tower performs best when the wet bulb temperature is low and relative humidity is high. Unfortunately, in the United States, favorable natural draft conditions do not normally occur simultaneously with high power demand periods. This non-coincidence, the relatively high expense of natural-draft towers, and the usual availability of river or lake water help explain the relative unpopularity of natural-draft cooling towers in this country.

Evaporative cooling towers were not used for Indian Point Unit No. 3 because there was no apparent need for them from an environmental standpoint. To add a single natural draft cooling tower or three banks of mechanical draft towers at this time would cost approximately $60 million dollars.

Beyond the capital cost associated with the addition of cooling towers, there would be significant operating costs caused by unit derating resulting from additional auxiliary power requirements and thermodynamic performance deterioration, added maintenance, and cost of chemical treatment of make-up and possibly tower blowdown water. For a mechanical draft cooling tower the additional fuel cost due to performance deterioration and additional auxiliary power requirements would be $1,950,000 per year and the cost due to capacity loss would be $17,000,000. For a natural draft cooling tower, the additional fuel cost due to performance deterioration and additional auxiliary power requirements would be $2,000,000 per year and the cost due to capacity loss would be $22,000,000.

A further consideration for the evaporative alternatives is the fact that the Hudson River in the vicinity of Indian Point has a salinity content of 100 to 7,000 ppm. Hudson River water would be used as make-up to compensate for evaporative losses drift, and blowdown (approximately 30 million gallons a day) in a closed cycle or in the open cycle case, the total flow over the tower. The feasibility of piping this amount of makeup water from the

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*J. C. Campbell, A New Look at Cooling Towers for the Power Generation Industry, presented at Cooling Tower Institute Winter Meeting, January, 1969, Houston, Texas.

New York State Chelsea Pumping Station was investigated in 1970. The study indicated that while no particular engineering design difficulty would be anticipated, the capital investment would be high enough to make this project impractical. Also, there may be environmental (biological) problems due to the extensive construction and installation of the piping in the river. Finally the availability and the right-of-way would be another serious consideration. The estimated cost of such a pipeline system is as follows:

Capital cost (1971) - Pipeline, substation intake pump and pumping station plus indirect cost.	$31,000,000
Annual Operation maintenance & Insurance	$1,024,000

(e) Natural Cooling Ponds

A natural cooling pond is a simple method resembling the once-through cooling system except that the warm condenser circulating water outlet is first channeled to a pond (rather than directly to the river). Heat transfer by various physical processes, such as radiation, convection, and evaporation takes place in the pond and the cooled water is then recirculated to the condenser inlet (for closed-cycle operation) or simply returned to the river.

This cooling system is simple and requires no complicated construction. Its disadvantages may include fogging, icing and blowdown problems. Furthermore, its extensive surface area requirements, ranging from two to three acres per MW(e) for nuclear plants,* would require close to 3,000 acres for a plant with Indian Point Unit No. 3's capacity. Since the total Indian Point site is only 239 acres, this eliminates cooling ponds as a possible cooling method for Indian Point Unit No. 3.

The additional fuel cost due to performance deterioration would be approximately $2,580,000 dollars per year and the cost due to capacity loss would be $22,900,000 dollars per year.

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*D. O. Lima, Pond Cooling by Surface Evaporation, Power, March 1966.

(f) Spray Ponds

Spray ponds are a modification of natural cooling ponds and perform similarly to wet cooling towers. In spray ponds, heat from the water is transferred primarily through eveporation and partly by conduction to ambient air.

Spray pond cooling systems use nozzles that atomize water into droplets or fine particles to give the most effective heat transfer area per unit volume of water. Both the spray height and spray size, which depend on design pressure affect the system thermal performance and drift loss. Higher pressure produces a higher dispersion of finer spray that may be blown away by the wind, the lower pressure produces a lower level of larger droplets which when compared with smaller droplets, provide smaller surface area per unit weight and shorter travelling time for effective heat transfer.

The powered spray module (PSM) system consists of multiple, independently operated units arranged in series - parallel. A floating control pump assembly in each unit sucks water from a canal and distributes it through below-surface piping to four isolated, floating spray nozzles (see Figure 17-6). After the water is cooled by being sprayed through the initial spray modules, it falls back into the canal and is reprocessed by other spray modules installed downstream.

To add a spray pond at this time would require approximately 60 acres of land and would cost approximately $75 million dollars. The additional fuel cost due to performance deterioration and additional auxiliary power requirements would be $2,580,000 per year and the cost due to capacity loss would be $22,900,000.

There are adverse environmental effects associated with a spray pond at Indian Point. During winter operation, drift and spray would result in severe local icing. The effect of salt content of the spray is not known but it is highly likely that the local flora would be severely affected. Under adverse humidity conditions, local fogging can occur. Also, their performance is dependent upon wind speed and direction.

(g) Beneficial Use of Heat

All the above alternative cooling systems are specifically designed for heat rejection to the environment. It would be highly desirable to be able to use this rejected heat in some beneficial way. For example, this heat might be considered for low grade thermal needs such as domestic and low temperature processes. However, these facilities require temperature levels not compatible with the existing Indian Point Unit 3 turbine-generator and are not immediately adjacent to the heat source. There is no potential for high domestic of industrial consumption of heat within the proximity of Indian Point.

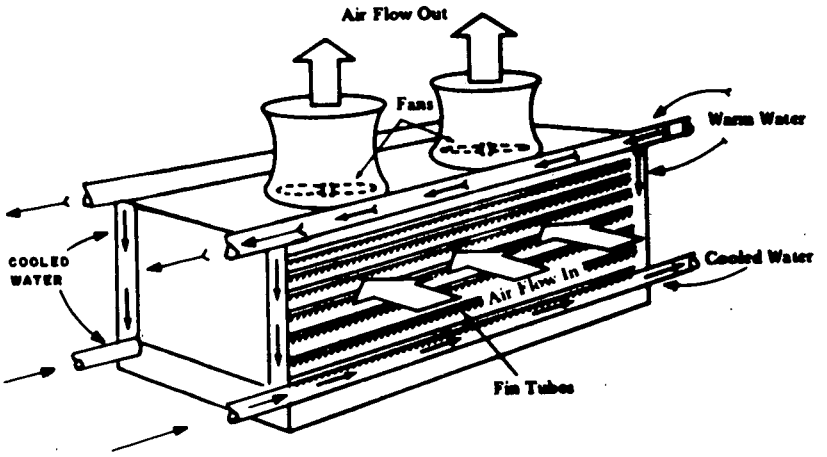

Figure 17-1. Dry Cooling Tower

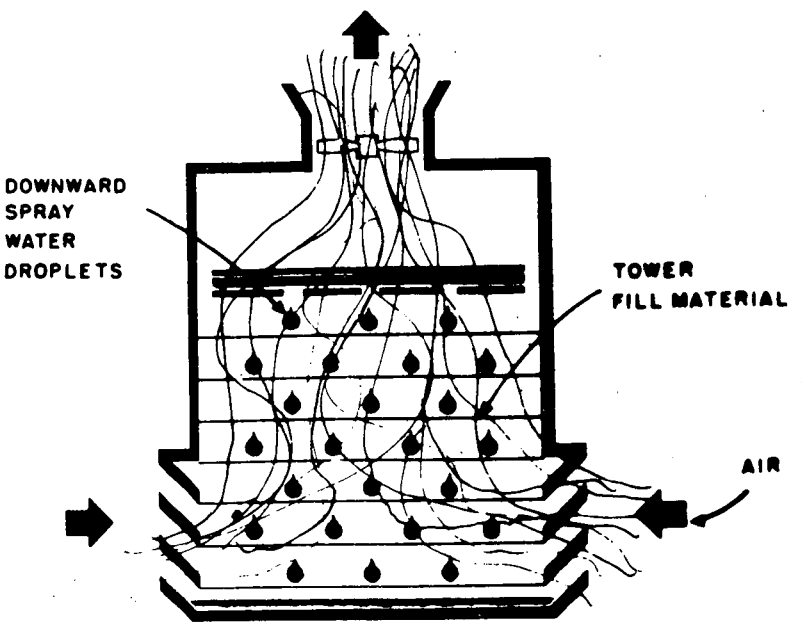

Figure 17-2. Mechanical - Draft Wet Tower (Counterflow)

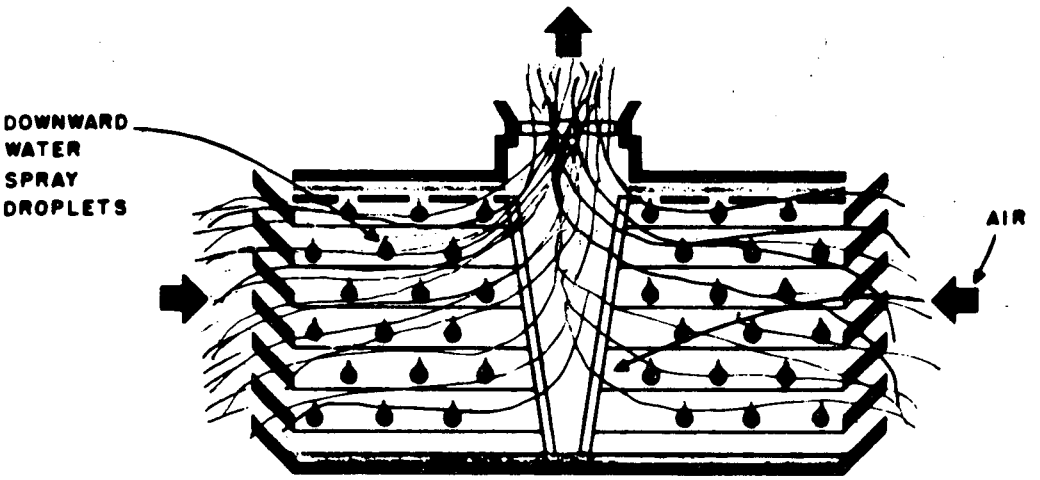

Figure 17-3. Mechanical - Draft Wet Tower (Crossflow)

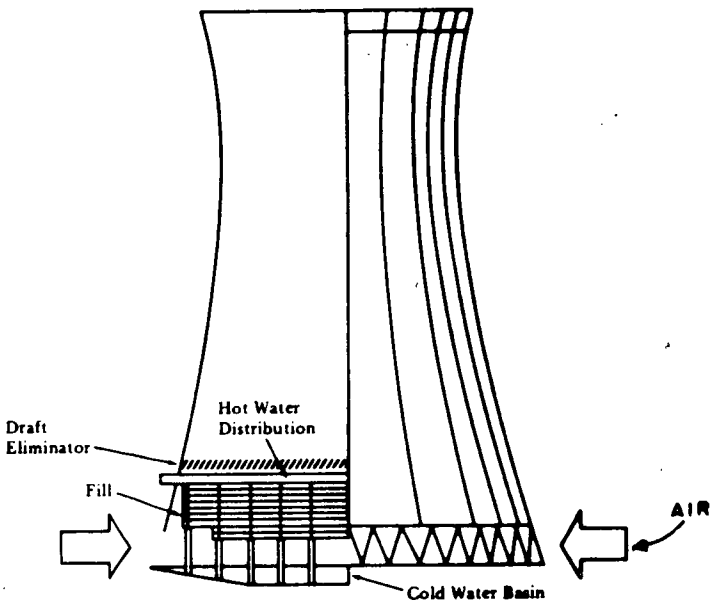

Figure 17-4. Natural - Draft Wet Tower (Counterflow)

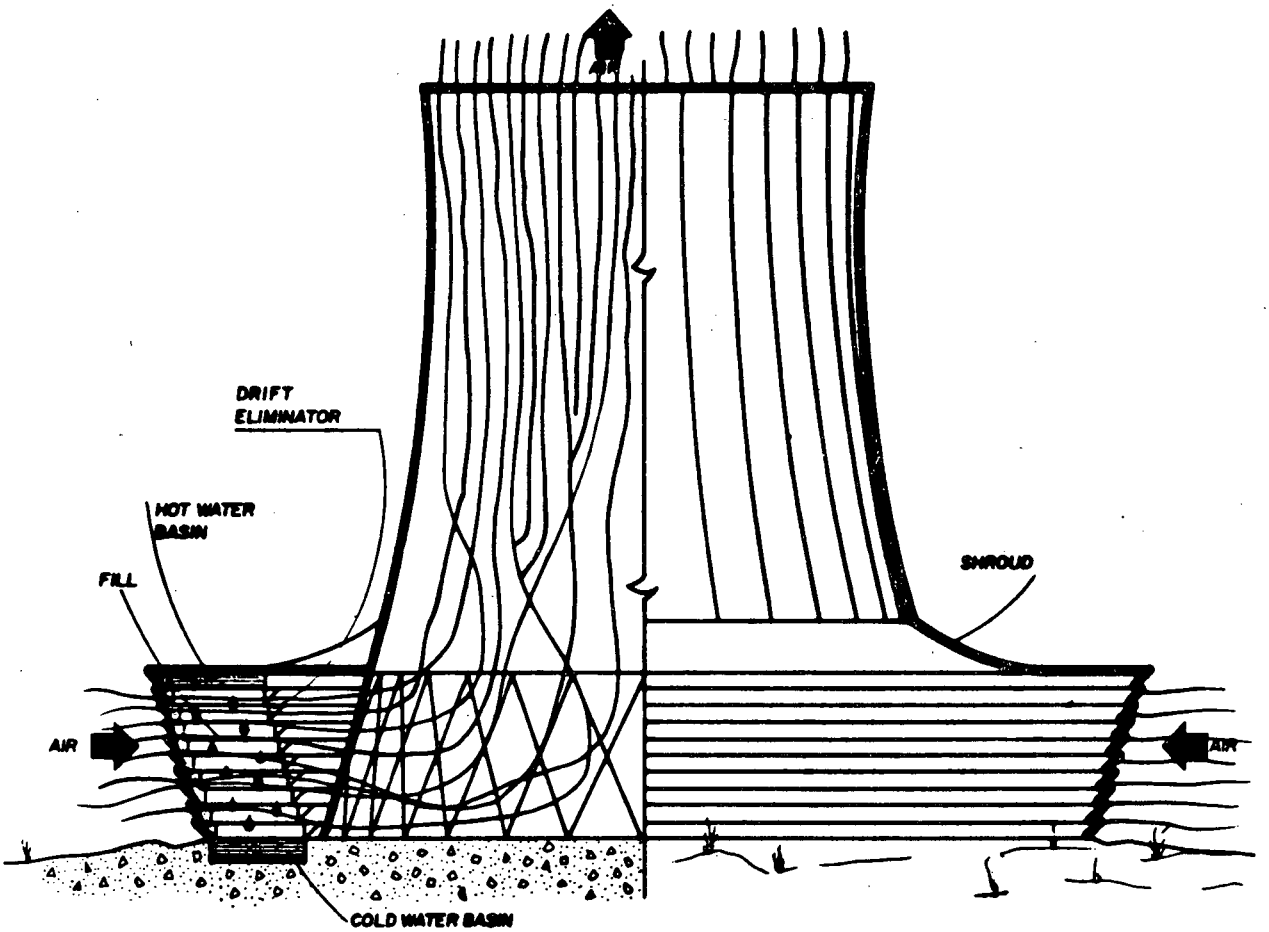

Figure 17-5. Natural - Draft Wet Tower (Crossflow)

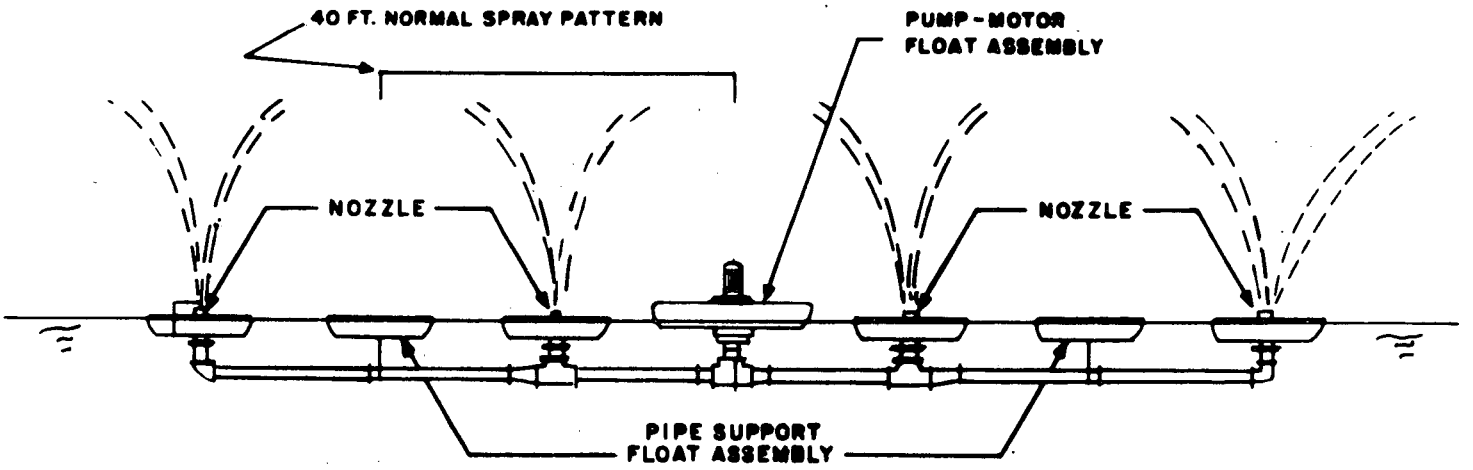

Figure 17-6. Spray-Pond Cooling with Power Spray Modules

17.3.3 Benefit-Cost Analysis

(a) General

The foregoing analysis shows that the only feasible alternatives are closed-cycle evaporative cooling towers and spray ponds. These would require very large economic costs as described earlier. The benefit of these alternatives would be the avoidance of thermal discharges to the Hudson River. The environmental effects of these discharges have been discussed in Section 9.0. In view of the minimal nature of these effects, Con Edison does not believe there is any justification for incurring these costs. In addition, some reduction in fish impingement may also be realized.

The adverse environmental effects that closed cycle evaporative cooling towers and spray ponds may introduce have already been noted.

The purpose of this section is to provide additional documentation in support of the engineering and cost information presented with regard to the alternative cooling systems selected for discussion in the Benefit/Cost analysis (Section 22). These alternatives are as follows:

Natural draft wet cooling towers operated in a closed-cycle configuration (Alternative BB).

Mechanical draft wet cooling towers operated in a closed-cycle configuration (Alternative BC).

Land-based spray ponds operated in a closed cycle configuration (Alternative BD).

The scope of the information provided for each of the cooling alternatives considered is as follows: location and physical arrangement, structural modifications, cost estimates (capital, contingency and maintenance) and design assumptions.

(b) Location and Physical Arrangement

Figures 17-7 through 17-9 show the location (south of Unit 3) and the physical arrangement of each of the alternative cooling systems.

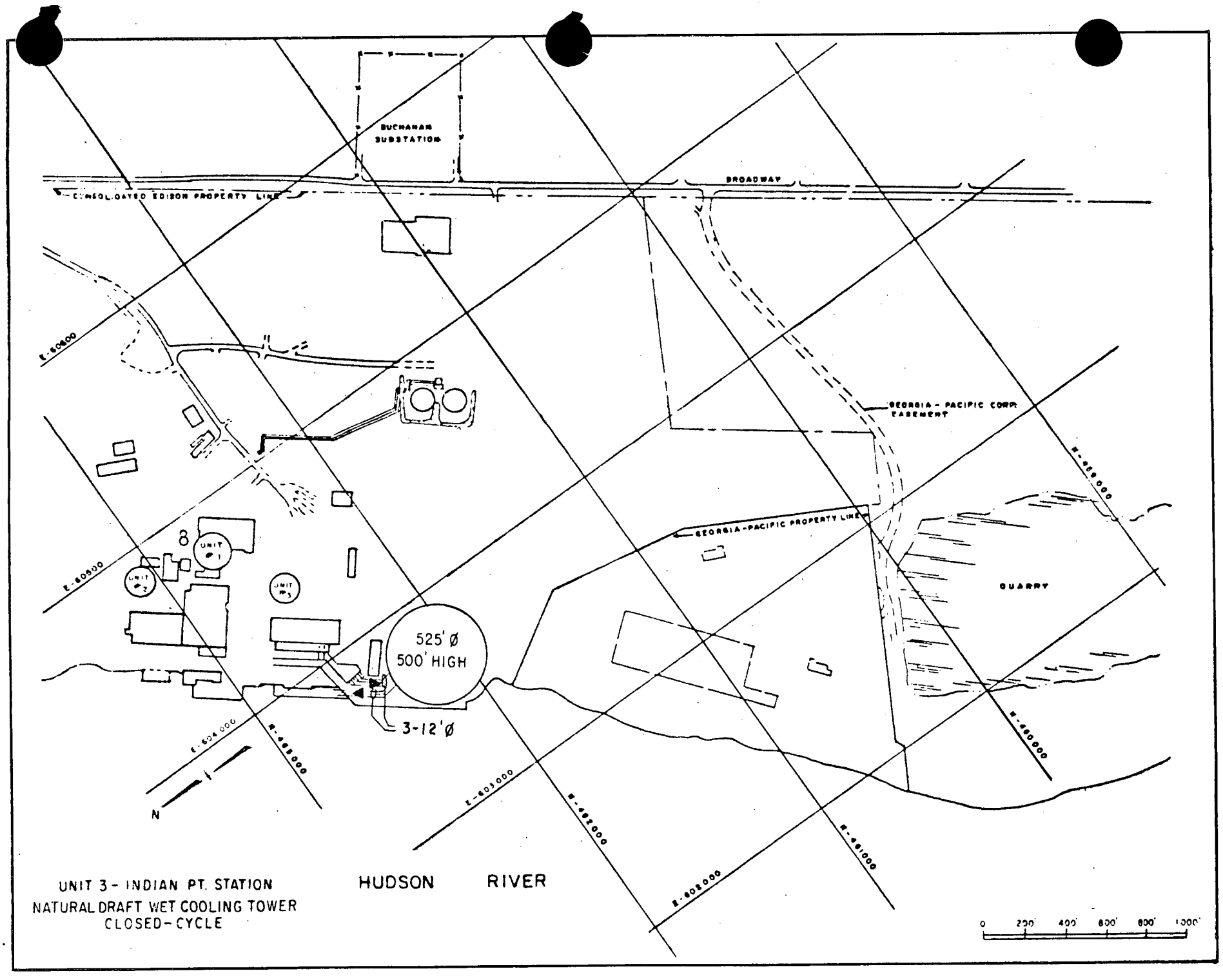

Figure 17-7 Unit 3 — Indian Point Station Natural Draft Wet Cooling Tower Closed-Cycle

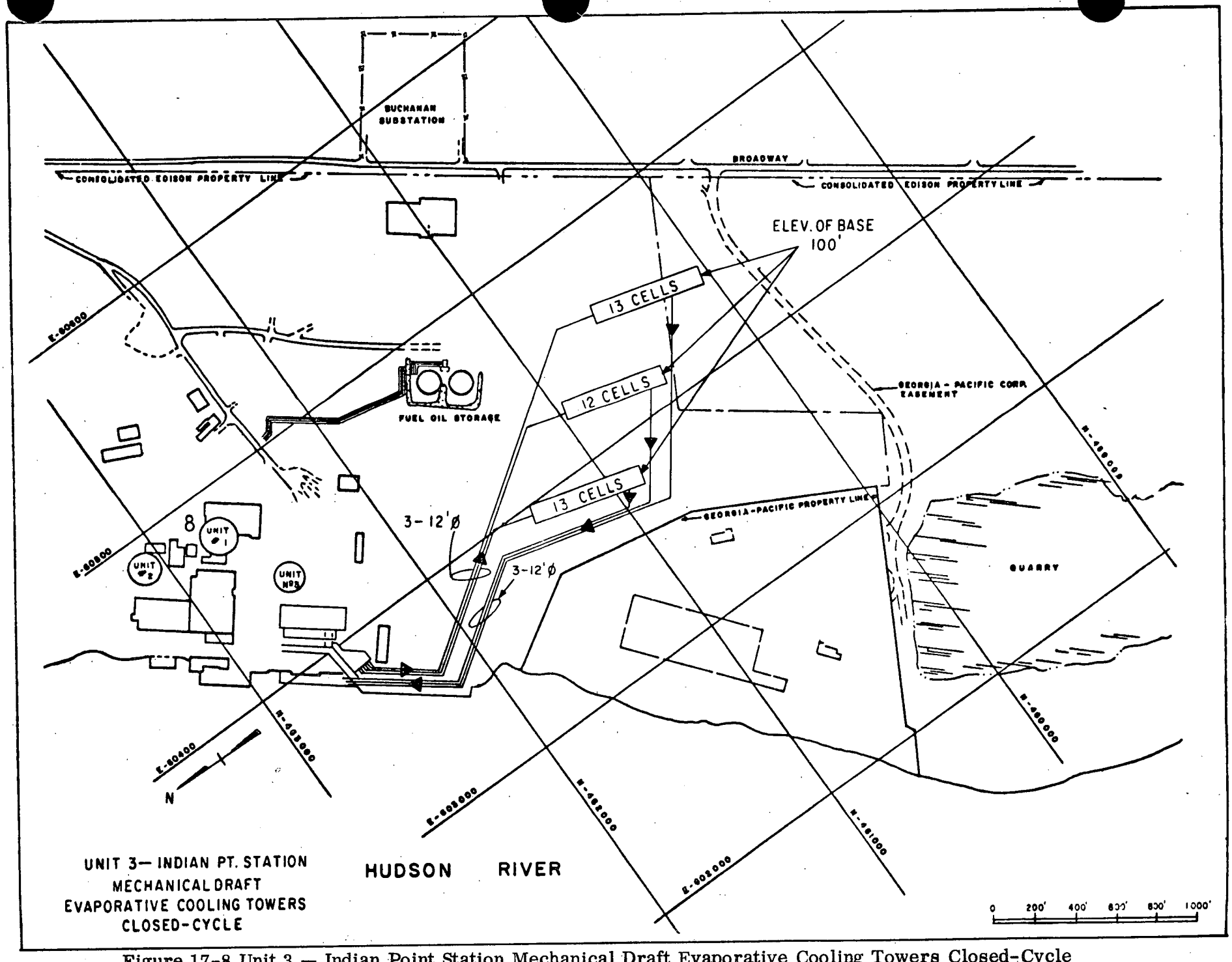

Figure 17-8 Unit 3 — Indian Point Station Mechanical Draft Evaporative Cooling Towers Closed-Cycle

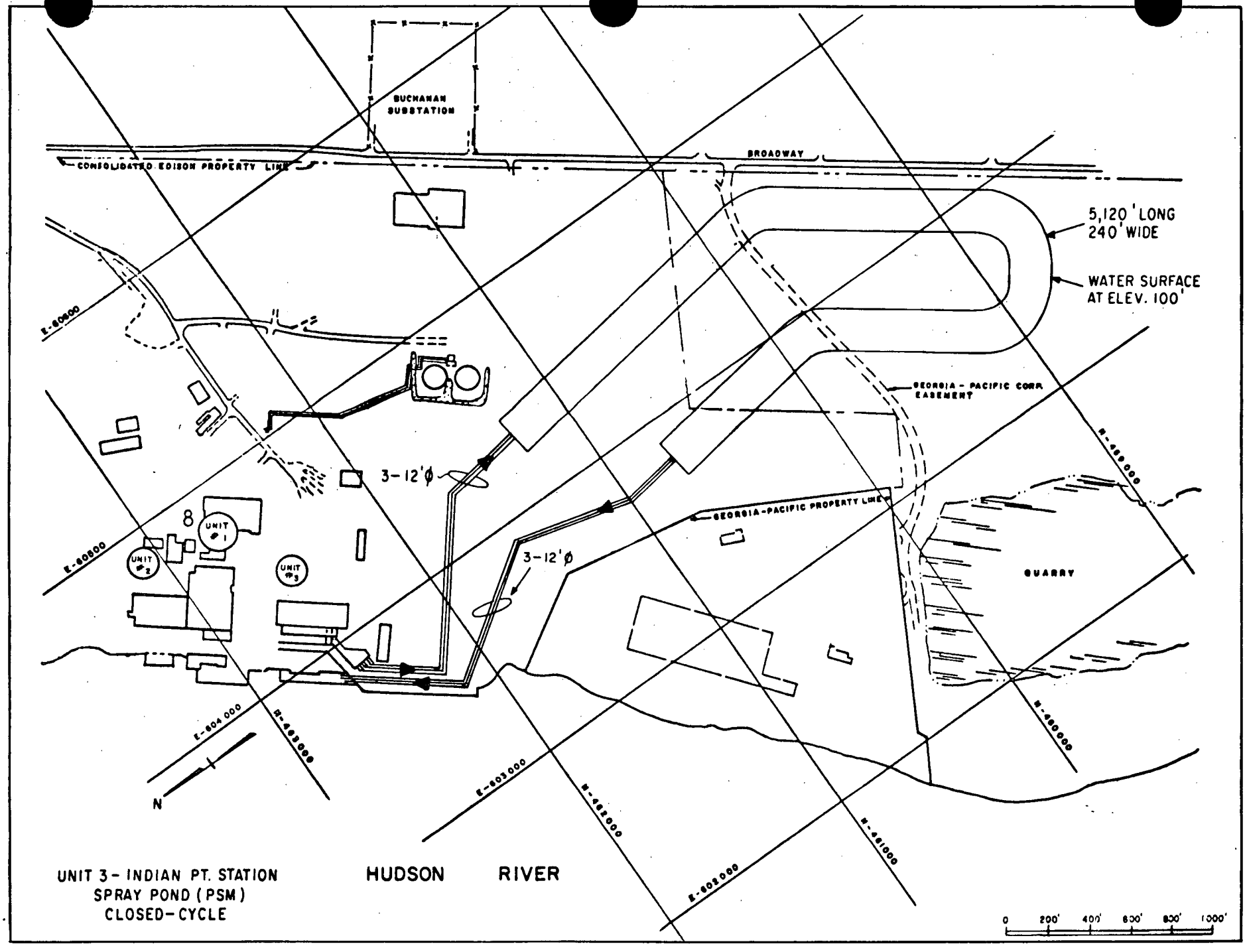

Figure 17-9 Unit 3 — Indian Point Station Spray Pond (PSM) Closed-Cycle

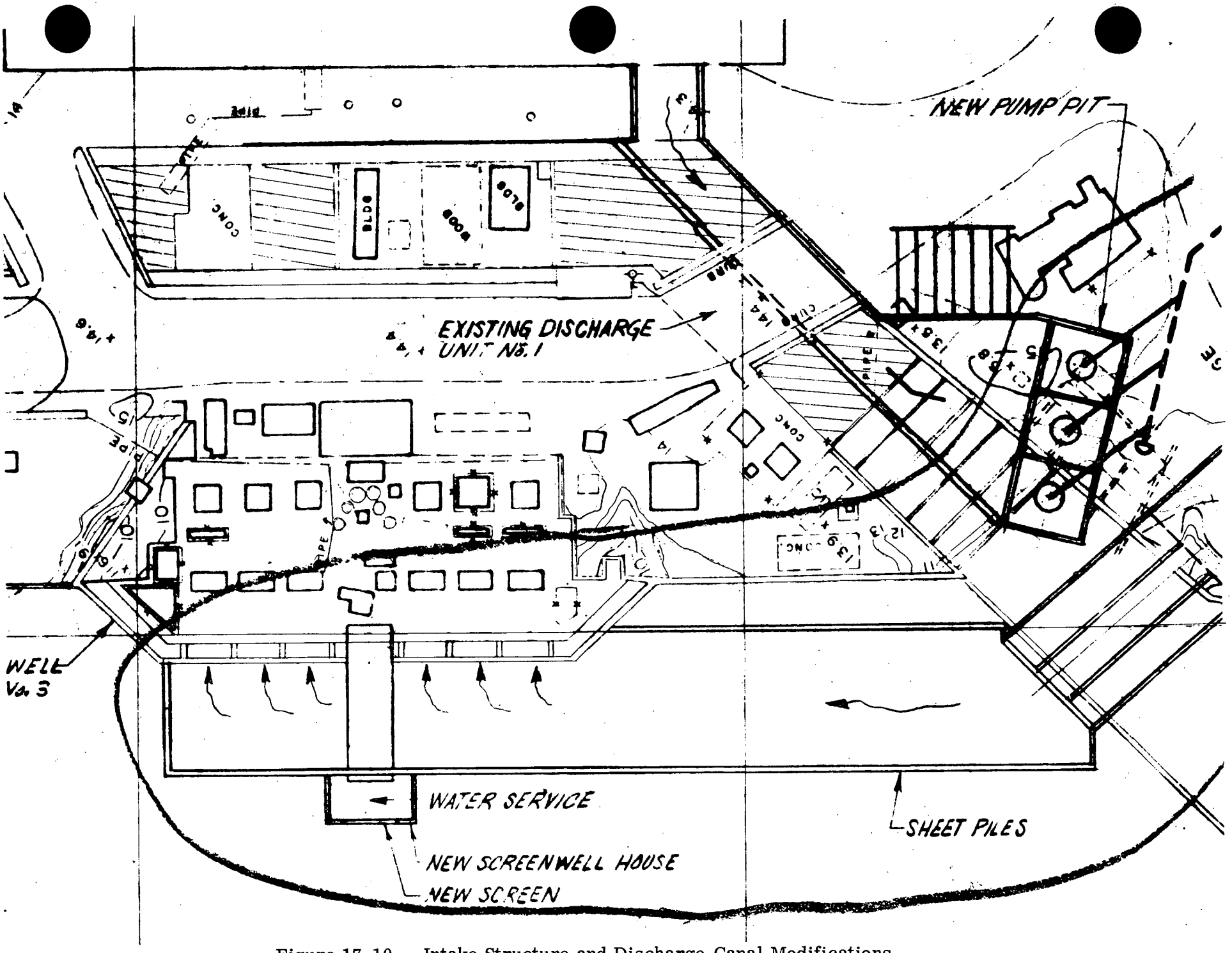

Figure 17-10 — Intake Structure and Discharge Canal Modifications

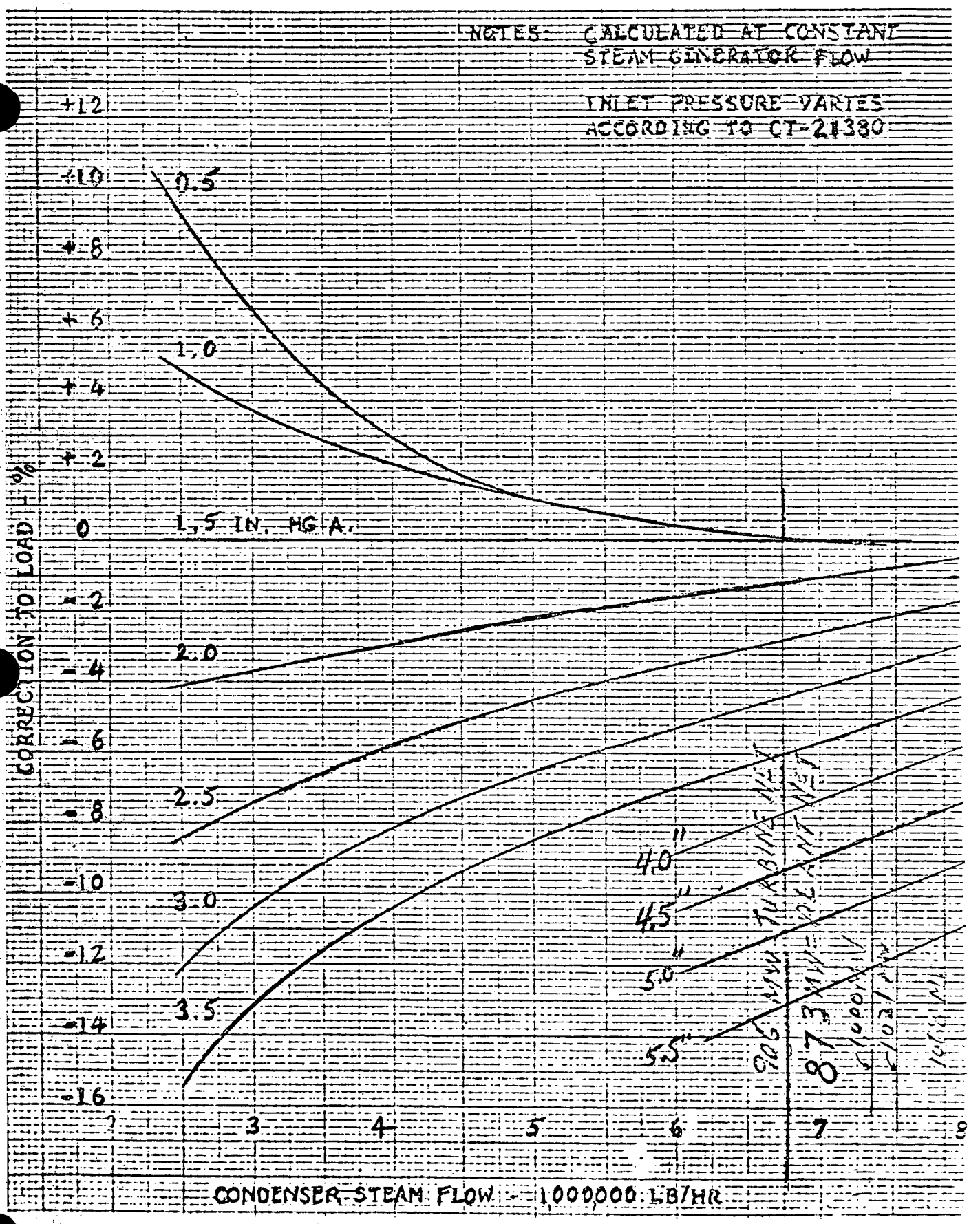

Figure 17-11 — Vacuum Correction to Load

Table 17-2 presents a physical description (size and number) of the major equipment, structures and components such as cooling towers or spray modules, circulating water booster pumps and piping runs for each of the alternatives considered.

(c) Major Construction Details

Major construction work anticipated for each of the proposed cooling systems is described below:

(1) Clearing, Grading, Excavation and Foundations

The clearing, grading, excavation and foundation requirements are based on the land area and volume necessary for the alternative cooling systems, and the nature of the land occupied. Spray ponds occupy the most area whereas mechanical-draft cooling towers require the least. With regard to foundation loads, natural-draft cooling towers have the largest and spray ponds have the smallest. For the location selected, cover clearing, earth excavation, rock excavation, removal of rubble and grading would be required.

(2) Condenser Discharge Tunnel Modification

The condenser discharge tunnel connecting Unit 3 with the river discharge canal would be blocked off as required to prevent Unit 3 condenser coolant from by-passing the cooling towers or spray pond. This could be accomplished by installing stop logs at suitable locations, as indicated in Figure 17-10. Figure 17-10 also shows a new canal to be constructed, outside the Unit 3 Turbine-Generator Building, leading to a new circulating-water booster pump house.

(3) Circulating Water Booster Pump-House

Vertical circulating water booster pumps would be placed in a pump-house south of the Unit 3 Turbine-Generator Building.

(4) Piping Installation

Most of the piping leading to and returning from cooling towers or cooling ponds probably would be underground, except for those segments which may be elevated in the immediate vicinity of the cooling element. Should an alternative be selected for detailed design, it may be desirable to install some additional piping above ground.

TABLE — 17-2

PHYSICAL DESCRIPTION OF ALTERNATIVE COOLING SYSTEMS

Title	CLOSED CYCLE		
	Nat. Draft BB	Mech. Draft BC	Spray Pond BC
Cooling Elements			
a. No. of Nat. Draft Towers, Mech. Draft Cells or Spray Modules	1	38	192
b. Dimension:		Two 520	
Length or dia., ft.	525	One 480	5,120
Width, ft.	--	70	240
Height, ft.	500	60	--
c. No. of motors	--	38	192
d. BHP (each)	--	200	75
e. Static Pump Head, ft.	100	140	100
Circ. Water Booster Pumps			
a. No.	6	6	6
b. Cap. (each) 10^3 gpm	145	145	145
c. TDH, ft.	120	160	120
d. BHP, (total)	33,000	44,000	33,000
Piping			
a. Dia. ft.	12	12	12
b. Length, ft.	3,700	13,200	11,500
Dimensions			

(5) Intake Structure Modification

As shown in Figure 17-10, the modified intake structure would include a sheet-pile enclosing structure with provisions for supplying river makeup water for the closed-cycle operation and river water to the service water pump pit. Flow control weirs would be required to regulate water level at each circulating water pump pit.

(6) Blowdown Line

A 22-inch blowdown line with a motor-operated valve would be provided as a by-pass across the seal in the condenser discharge tunnel to allow discharge of chemical and radioactive wastes from the plant through the river discharge canal.

(7) Auxiliary Transformer

One plant auxiliary transformer would be required to serve the new motors for circulating water booster pumps, mechanical-draft tower fan motors, spray module pump motors, and related electrical equipment.

(d) Cost Estimates

(1) Capital Estimates and Contingencies

Table 17-3 shows the estimated capital cost and the total cost including contingencies for the installation of each of the cooling system alternatives beginning in 1973 and ending in 1976. These estimates are based upon the items listed in Table 17-2 and the construction work discussed in Section (c).

The major costs are the installed cost of the cooling elements, the cost of excavation and foundations and the (installed) cost of piping. As can be seen from Table 17-3, the natural draft cooling alternative has the lowest estimated capital cost while the spray pond alternative has the highest estimated capital cost.

The contingencies used to estimate the total cost of each of the cooling alternatives are detailed in Table 17-4, for each million dollars of capital expended.

TABLE — 17-3

COST ESTIMATES FOR COOLING SYSTEM ALTERNATIVES
(MILLIONS OF DOLLARS)

	CLOSED CYCLE		
	Nat. Draft	Mech. Draft	Spray Ponds
Excavation and Foundation	8.75	3.20	10.90
Modify Intake Structure	0.75	0.75	0.75
Booster Pump House	1.47	1.47	1.47
Cooling Element (Installed)	10.00	4.60	4.00
Booster Pumps (Installed)	1.78	1.67	1.44
Piping:			
Condenser — Pump House	0.20	0.20	0.20
Pump House — Cooling Element	5.00	17.72	15.38
Blowdown Line	0.07	0.07	0.07
Electrical Costs	3.25	4.60	5.80
TOTAL (BASE COST)	31.27	34.28	40.01
TOTAL (WITH CONTINGENCY AND ESCALATION)	58.66	64.31	75.06

TABLE — 17-4

CAPITAL ESTIMATE SUMMARY

CAPITAL ESTIMATE SUMMARY

ESTIMATE NO.

PROJECT/LAYOUT NO.

ACCOUNT NO. DATE 9/1/72

REQUESTED BY

LOCATION/DESCRIPTION

ESTIMATED BY

Installation of Cooling System

CHECKED BY

Alternatives for Indian Point

PROJECT START DATE 1973

Unit No. 3

PROJECT COMPLETE DATE 1976

CONTRACT LABOR AND MATERIAL (UNIT PRICE CONTRACTS)		1,000,000
COMPANY LABOR		20,000
PROJECT MANAGEMENT AND INSPECTION		
COMPANY TRANSPORTATION		
CONTRACT LABOR		
CONTRACT MATERIAL		
OVERHEAD AND PROFIT ON CONTRACT MATERIAL		
COMPANY MATERIAL		
SALES TAX		
STORES HANDLING		
TOTAL DIRECT COST		1,020,000
20 % CONTINGENCIES		204,000
SUB TOTAL WITH CONTINGENCIES		1,224,000
12 % ENGINEERING AND ENGINEERING SUPERVISION		147,000
SUB TOTAL WITH ENGINEERING		1,371,000
1.6 % ADMINISTRATION AND SUPERVISION		22,000
		1,393,000
PAYROLL TAXES AND PENSIONS		
% OF COMPANY LABOR		
21.5% OF COMPANY ENGINEERING	32,000	
		32,000
SUB TOTAL		1,425,000
17.5% ESCALATION		250,000
ESCALATED TOTAL		1,675,000
12 % INTEREST DURING CONSTRUCTION		201,000
		1,876,000
ESTIMATED TOTAL		

ESTIMATE BASED ON

CONSTRUCTION DEPT. CONCURRANCE BY

(2) Maintenance Costs

For the natural draft tower, the cost of maintaining the fill was estimated at $200,000 dollars per year.

For the mechanical draft towers, the cost of maintaining the fill was estimated at $13,000 per year per cell. The cost of maintaining the 200 HP fan motors was estimated at $4,000 per year per motor. The total cost of maintaining the mechanical draft towers would be $647,000 per year which includes $495,000 for the fill and $152,000 for the fan motors.

For the spray pond, maintenance was estimated at $1,500 per 75 HP motor per year.

The incremental generating costs associated with each of the cooling system alternatives are discussed in the "BENEFITS" section of the Benefit/Cost analysis (Section 22).

(e) Design Assumptions

(1) Wet Bulb Temperature

The wet bulb temperature is the equilibrium temperature that would be measured if air was adiabatically saturated with moisture. A peak wet bulb ambient air temperature of 77°F and a summer average wet bulb temperature of 65°F were used as the basis for the performance calculations. Typically, the wet bulb temperature will equal or exceed 77°F in the vicinity of Indian Point only during 1% of the summer months. Although no precise measurements of the wet bulb temperature in the vicinity of Indian Point presently exist, wet bulb temperature measurements for air conditioning purposes do exist for surrounding areas.* These measurements show the wet bulb temperature to be in the range of 70 to 80°F. These wet bulb temperatures have been and are being used for design within the Indian Point area and have not caused design inadequacies to the knowledge of Con Edison.

A river water temperature of 75°F at the condenser inlet was used in order to compare the power generation loss of each of the cooling alternatives to the once-through cooling

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*Cooling Tower Fundamentals and Application Principles published by Marley Company, 1969.

system. This temperature is more representative of the yearly average maximum river water temperature than the highest-ever recorded value of 79°F which occurs infrequently.

(2) Approach Temperature

The approach temperature is defined as the temperature of the effluent from the cooling element (tower or pond) less the ambient air wet bulb temperature. For the closed-cycle alternatives, a high approach temperature can be realized because the cooling element effluent is returned to the condenser inlet and not discharged to the river. Under these conditions, the primary consideration is balancing generation losses against the capital investment and the operating costs of the plant. High approach temperatures reduce the number and the size of the cooling elements required, but also result in larger generation losses. The approach temperatures selected for the closed cycle cooling alternatives for the 77°F wet bulb temperature condition are as follows: 22°F for the natural draft cooling towers, 15°F for the mechanical draft cooling towers, and 20°F for the spray pond. The size and the number of the cooling elements listed in Table 17-2 are based on these approach temperatures.

(3) Range

The temperature range of a cooling element is defined as the difference between the cooling element inlet and effluent temperatures. This parameter depends on the plant electrical output, the reactor thermal output, the turbine exhaust pressure and the cooling water flow rate through the condenser. For Indian Point Unit No. 3 operating at the initial turbine guarantee of 1000 MW (gross), the design values are as follows: 3025 MW(t) reactor output, 1.5" Hg absolute turbine exhaust pressure and a condenser cooling water flow rate of 840,000 gpm and service water cooling in the amount of 30,000 gpm, thus making a total of 870,000 gpm.

For closed-cycle cooling, the cooling element temperature range is equal to the temperature rise across the condenser (16.5°F). All the heat absorbed by the cooling water passing through the condenser is rejected to the atmosphere by the cooling element.

(4) Main Turbine Exhaust Pressure

The saturation temperature of the main turbine exhaust steam determines the main turbine exhaust pressure. Once the turbine exhaust pressure is known, then the resulting turbine output load can be determined. The saturation temperature is found by summing the wet bulb temperature, the approach temperature, the temperature range and the condenser terminal temperature difference with allowance for air in-leakage. This technique was used to calculate the peak generation losses for each alternative shown in Table 17-5.

In order to illustrate this technique, consider a closed cycle natural draft cooling tower operating with the following conditions: a peak wet bulb temperature of 77°F; an approach temperature of 22°F; a temperature range of 16.5°F and a condenser terminal temperature difference of 9.5°F. The saturation temperature of the main turbine exhaust steam is 125°F. This corresponds to an exhaust steam pressure of 3.95" Hg absolute. From vendor's data (Figure 17-11), the load correction factor for a 3.95" Hg absolute exhaust steam pressure and a turbine rating of 1000 MW (gross) is approximately -6.8% or a load reduction of 68 MW. The resulting net turbine output is then 932 MW (Item 1, Table 17-5).

For the once-through cooling system operating with a 75°F river water ambient temperature, a 16.2°F temperature rise across the condenser and a condenser terminal temperature of 9.5°F, the resulting saturation temperature is 100.7°F. This results in a main turbine exhaust pressure of 1.97" Hg absolute. Referring to Figure 17-11, the load correction factor for these conditions is approximately -1.0% or a load reduction of 10 MW. Thus, the net turbine output is 990 MW (footnote (a), Table 17-5). Item 2, Table 17-5 shows the incremental generation loss (58 MW) with respect to the once-through cooling system. In addition, 24.7 MW of auxiliary power is required for the circulating water booster pumps (Item 3, Table 17-5). The total derating resulting from the closed-cycle natural draft cooling alternative is 82.7 MW (Item 4, Table 17-5). Since the power requirement of the normal plant auxiliary loads is 35 MW, the net plant output is 872.3 MW (Item 7, Table 17-5). The values listed for the other alternatives listed in Table 17-5 were obtained in the same fashion.

TABLE — 17-5

GENERATION CAPABILITY OF COOLING SYSTEM ALTERNATIVES
FOR 77°F WET BULB TEMPERATURE
(TURBINE RATING — 1000 MW GROSS)

	CLOSED CYCLE		
	Nat. Draft BB	Mech. Draft BC	Spray Pond BD
1. Net Turbine Output With Alternative, Mw	932 (3.95")	956 (3.25")	939 (3.75")
2. Incremental Loss of Turbine Capacity (With Respect to Once-Through System) (Mw) (a)	58.0	34.0	51.0
3. Cooling System Auxiliaries, Mw	24.7	30.3	35.4
4. Derating Because of Alternative, Mw (2+3)	82.7	64.3	86.4
5. Normal Plant Auxiliary Load, Mw	35.0	35.0	35.0
6. Total Derating, Mw (4+5)	117.7	99.3	121.4
7. Net Plant Output, Mw	872.3	890.7	868.6

(a) The turbine net Mw for the once-through cooling system is 990 (2.00" Hg absolute).

Table 17-6 shows for each alternative cooling system the yearly average generation loss and the resulting increased net plant heat rate. To calculate the turbine capacity loss for a closed-cycle natural draft cooling tower on an average summer day, the following conditions were assumed: a summer average wet bulb temperature of 65°F, a 30°F approach temperature, a 16.5°F temperature range and an 9.5°F condenser terminal temperature difference. The resulting saturation temperature of 121°F corresponds to an exhaust steam pressure of 3.54" Hg absolute. Referring to Figure 17-11, the load correction factor for these conditions is -5.2% or a load reduction of 52 MW. To obtain a yearly average capacity loss, the average summer day derating was divided by four resulting in a loss of 13 MW (Item 1, Table 17-6). This capacity loss combined with power requirements for cooling system auxiliaries (24.7 MW) and normal plant auxiliary loads (35 MW) results in a total derating of 72.7 MW. The net plant output is then 927.3 MW (Item 6, Table 17-6). The net plant heat rate (Item 7) is the reactor thermal output (3025 MW(t)) divided by the net plant output (927.3 MW) or 11,132 Btu/kwhr. The values for the other alternatives listed in Table 17-6 were obtained in the same manner.

(5) Drift

The drift assumptions for the various cooling elements considered were derived from the following sources:

a) With regard to natural draft cooling towers, studies (including test measurements) performed by Pickard, Lowe and Associates - "Forked River Nuclear Station Unit 1 Natural Draft Salt Water Cooling Tower - Assessment of Environmental Effects," published January 1972 indicate that the drift from such devices is 0.0025%.

b) For spray pond modules, vendors estimate the drift to be 0.004%.

c) For mechanical draft cooling towers, vendors guarantee 0.008% drifter.

(6) Blowdown

The blowdown rate for each closed-cycle cooling alternative was based on the requirement of maintaining the concentration of the closed cycle cooling water at two cycles. This

TABLE — 17-6

YEARLY AVERAGE GENERATION CAPABILITY AND CHANGE IN NET PLANT HEAT RATE FOR ALTERNATIVE COOLING SYSTEMS (TURBINE RATING - 1000 MW GROSS)

Item	CLOSED CYCLE		
	Nat. Draft BB	Mech. Draft BC	Spray Pond BD
1. Loss of Turbine Capacity, Mw Average (a)	13.0	6.5	11.0
2. Cooling System Auxiliaries, Mw	24.7	30.3	35.4
3. Sub-Total Derating Because of Alternative, Mw (2+3)	37.7	36.8	46.4
4. Normal Plant Auxiliary Load, Mw	35.0	35.0	35.0
5. Total Derating, Mw (3+4)	72.7	71.8	81.4
6. Net Plant Output, Mw (Gross rating -5.)	927.3	928.2	918.6
7. Net Plant Heat Rate (Btu/kwhr) (b)	11,132	11,122	11,238

NOTES:

(a) Yearly average derating is equal to 1/4 average summer day derating.

(b). For turbine rating of 1000 Mw (gross) net plant heat rate for once-through cooling system is 10,697 Btu/kwhr.

limit was selected on the basis of data collected by the U. S. Geological Survey at Tompkins Cove, N. Y. (Table 4-1 of the Indian Point Unit No. 3 Environmental Report) and studies performed by Quirk, Lawler and Matusky (Figure 13 of Appendix A and Figure 2 of Appendix J of the Indian Point Unit No. 3 Environmental Report) which show that for the major part of the year the blowdown concentration would not exceed the maximum river salinity expected during the year.

The blowdown rate is also influenced by drift and evaporation. The drift assumptions were discussed in Subsection (5). The evaporation will be 1% of the circulating water for every 10°F of cooling range.*

The cooling element temperature range for closed cycle cooling is equal to the temperature rise across the condenser, 16.5°F. Therefore, it is assumed that 1.65% of the cooling water would be evaporated. Knowing the drift (D) and evaporation (E) effects, the blowdown rate (B) can be calculated using the following relationship: B (gpm) = 0.01 (E-D)% times the cooling flow (gpm). For example, for a natural draft cooling tower with a cooling flow of 870,000 gpm, the blowdown rate, B (gpm), is 0.01 (1.65-.0025) times 870,000 gpm or 14,333 gpm. Table 17-7 summarizes the drift, blowdown and evaporation losses for all three alternatives.

(7) Chemical Treatment

The application of intermittent chlorination at the inlet to the condenser provides tower growth inhibition. Controlling the pH of the circulating water and operating at only two cycles of concentration avoids the use of additional chemicals for scale control as well as minimizing the dissolved solids in blowdown.

During periods of reduced salinity which may be accompanied by an increase in the ratio of calcium to sulfate content in the circulating water, the use of sulfuric acid would be employed to exchange sulfate for bicarbonate ions in the circulating water. Since the

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*Betz Handbook of Industrial Water Conditions, P255 and Leung and Moore; Combustion, Nov. 1970, "Water Consumption Determination for Steam Power Plant Cooling Towers."

TABLE — 17-7

BLOWDOWN, DRIFT AND EVAPORATION EFFECTS

		Nat. Draft	Mech. Draft	Spray Pond
Drift	% *	.0025	.008	.004
	gpm	22	69.6	34.8
	10^6 gpy	11.6	36.6	18.3
10^6 lbs. of TDS/yr.		1.06	3.35	1.68
Blowdown	% *	1.648	1.642	1.646
	gpm	14,333	14,285	14,320
	10^6 gpy	7,533	7,508	7,327
10^6 lbs. of TDS/yr		691	688	690
Evaporation	% *	1.65	1.65	1.65
	gpm	14,355	14,355	14,355

* percent of total circulating water (870,000 gpm)

gpy - gallons per year

TDS - total dissolved solids

solubility of calcium sulfate is much greater than calcium carbonate, the tendency of scaling occurring is avoided. In addition, this treatment tends to maintain the pH of the circulating water more nearly neutral.

(8) Thermal Discharge to River Calculation

a) Once Through Cooling System

The heat generated is found using the following relationship:

$$Q_i = M_i (\Delta h)_i$$

The steam flow to the condenser is as follows:

M_1 - Low Pressure Turbine Steam Exhaust (lbs/hr)	7,106,566	
M_2 - Boiler Feed Pump (lbs/hr)	141,561	
M_3 - Low Pressure Extraction for Moisture Removal (lbs/hr)	54,674	
	7,302,801	lbs/hr

The differential specific enthalpy for each component is:

Δh_1 - (993.9 - 59.7) = 934.2 B/hr per lb. of steam

Δh_2 - (969.8 - 59.7) = 910.1 B/hr per lb. of steam

Δh_3 - (1041.4 - 59.7) = 981.7 B/hr per lb. of steam

The resulting Q values are:

$$Q_1 = (7.107 \times 10^6)(934.2) = 6638.95 \times 10^6 \text{ Btu/hr}$$
$$Q_2 = (0.142 \times 10^6)(910.1) = 128.83 \times 10^6 \text{ Btu/hr}$$
$$Q_3 = (0.055 \times 10^6)(981.7) = \underline{53.67} \times 10^6 \text{ Btu/hr}$$
$$Q_{Total} = 6821.45 \times 10^6 \text{ Btu/hr}$$

The Service Water requirements (30,000 gpm or 15×10^6 lbs/hr) times the temperature rise (7.3°F Average rise) results in a Q of 109.5×10^6 Btu/yr. Therefore, the total Q is 6930.95×10^6. The actual value used is 6950×10^6 Btu/hr.

b) Open Cycle Alternatives

In order to determine the heat emitted to the water body on a yearly average basis, the year was broken into two time periods; summer and the remainder (fall, winter, spring) of the year. The average temperature conditions assumed for these two time periods are listed below:

	Summer Conditions °F	Remainder of Year Conditions °F
Average River Temperature	74	49
Average Rise Across Condenser	14.6	14.6
Condenser Water Outlet Temperature	88.6	63.6
Average Wet Bulb Temperature	65	35
Approach	11	21
Return to River Temperature	76	56
Tower Inlet Temperature	88.6	63.6
Tower Effluent Temperature	76.0	56.0
Range	12.6	7.6
Yearly Average Range	8.85°F	

The yearly average range of 8.85°F results in approximately 60% (8.85/14.6) of the heat absorbed in the condenser by the circulating water being rejected to the atmosphere. Therefore, the heat emitted to the river body is 40% of the 6950×10^6 Btu/hr calculated in part (a) or 2780×10^6 Btu/hr.

c) Closed Cycle Alternatives

The method used to calculate the heat emitted to the water body for closed cycle cooling is demonstrated for the natural draft cooling alternative. The heat carried by the blowdown from the cooling tower to the river can be found by taking the product of the flow rate of the blowdown water and the temperature difference between the blowdown water and river water. The temperature of the blowdown water exceeds the temperature of the river water by 22.5°F, as

a year-round average. This 22.5, when multiplied by a blowdown flow of 7.67×10^6 lbs/hr (1.648% of 870,000 gpm) gives 161.3×10^6 Btu/hr of heat discharged to the river. The temperature conditions assumed are listed below.

	Summer Conditions °F	Remainder of Year Conditions °F
Condenser Water Inlet Temperature	95	83
Rise Across Condenser	15.1	15.1
Condenser Water Outlet Temperature	110.1	98.1
Average Wet Bulb Temperature	65	35
Approach	30	37
Tower Effluent Temperature	95	72
Less Average River Temperature	74	49
Resultant River Temperature Rise	21	23
Yearly Average	22.5°F	

The heat discharged to the river for mechanical draft cooling towers (121×10^6 Btu/hr) and the spray pond (145×10^6 Btu/hr) was calculated in a similar manner.

18.0 PRODUCTIVITY AND USE OF RESOURCES

The use of the Indian Point site to provide electric power to an intensely populated area is unquestionably and substantially beneficial to the health, welfare and safety of the general public. Industrial, residential and recreational activities in the surrounding areas will not be compromised or curtailed in any way. In fact they will benefit.

Every possible effort has been made by Con Edison to insure that no adverse effect on the environment results from the operation of its Indian Point facility. Continuing monitoring programs will also contribute to assure that these efforts are successful.

Where such effects are unavoidable, they are, as is substantiated by this report, maintained within acceptable limits. Moreover, when it is compared with the utilization of fossil fuels and associated air pollution, Indian Point Unit No. 3 may have enhanced the overall health and safety of the general public while providing them the energy needed to maintain a high standard of living and consequently a wider share of life's amenities for all.

The construction and operation of the Indian Point generating station will involve the commitment and use of a certain amount of land, air and water. Of these, only land is removed as a resource available for other types of activity. The portion of this site used for the nuclear units will be small and the balance of the area is to be concurrently used for recreational and educational purposes. Moreover, there is no intrinsic reason why at the end of the useful life of this nuclear facility its ultimate decommissioning cannot be accomplished, and accomplished in a way which would leave the site a more useful resource than it was before the first unit was built. Thus, the short term use of the site for the generation of electricity and public recreation and educational purposes will enhance its long-term productivity. In addition, this short-term utilization of land, air and water at the Indian Point site is not considered to be an irreversible or irretrievable commitment of a resource.

The only resource used at Indian Point that is irretrievable is the Uranium-235 portion of the fuel consumed within the nuclear units. A report of the National Fuels and Study Group estimates that at today's rate of fuel consumption, our total recoverable reserves of fossil fuel would last some 800 years. But when projected increases in the rate of consumption are taken into account, the estimate of 800 years shrinks to 200 years or less. And, if low grade sources are left out of this calculation, the estimate shrinks

further to 100 years or less. Based on data recently published by the U. S. Atomic Energy Commission,* reserves of uranium potentially represent 10 to 50 times or more the energy equivalent of our reserves of fossil fuel. In this light, therefore, the utilization of Uranium-235 at the Indian Point facility not only represents the efficient use of a more abundant resource while postponing the depletion of valuable fossil resources, but is also consistent with the national policy of the United States to promote the peaceful use of atomic energy, a resource which has become available through the harnessing of the atom.

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* Civilian Nuclear Power -- A Report To The President -- 1962, U. S. Atomic Energy Commission, Washington, D. C.

19.0 ACCIDENTS

This section considers as required the environmental risks due to the postulated classes of accidents designated in the AEC's "Scope of Applicants' Environmental Reports", dated September 1, 1971.

The design of various systems incorporated in the plant to mitigate the consequences of postulated accidents is based upon extremely conservative assumptions concerning system performance. However, in order to provide a realistic assessment of the environmental risk associated with these accidents, the evaluations in the following paragraphs use expected performance values based on the assumptions outlined in the proposed Annex to Appendix D to 10CFR50 issued December 1, 1971. A summary of the radiological consequences of each accident is presented in Table 19-1. Estimated environmental consequences are based on that portion of the 1970 census population within a 60-mile radius of the plant who receive at least 0.01 mRem of the genetically significant gamma whole body dose from the accident.

Class 2 — Small Releases Outside Containment

These releases are included and evaluated under routine releases in accordance with proposed Appendix I to 10CFR50. Such an evaluation is discussed in Section 14 of this Environmental Report.

Class 3 — Radwaste System Failure:

3.1 Equipment Leakage or Malfunction

The release of twenty-five percent of the average inventory of one of the large gas decay tanks employed in the Gaseous Waste Disposal System yields a gamma whole body dose of 0.15 mRem and a beta skin dose of 0.21 mRem at a point on the site boundary downwind of the plant. The estimated environmental consequence of such a dose is 0.02 Man-Rem. The release of twenty-five percent of the average inventory of the liquid waste hold-up tank onto the floor of the building would yield an inhalation dose to the thyroid of 0.013 mRem at the site boundary.

planned reserve capacity, including purchases from others, was 1,532 megawatts or 21% of its anticipated peak load.

In 1969, however, delays in the addition of new capacity by other utilities limited the amount of the firm purchased power actually available in that year at the time of the peak load to 260 megawatts, approximately one-third of the 710 megawatts for which Con Edison had contracted. In addition, there were several equipment outages and deratings* experienced during the summer period, which is the period of peak demand on the Company's system. As a consequence, the Company had to request large customers to reduce load voluntarily, to appeal to the general public to conserve electricity and to institute voltage reductions on eight different days on which the loss of capacity ranged from 800 to over 2,000 megawatts. On two occasions the voltage reduction reached the maximum allowable level of 8%**, after which the only load control device available to maintain the integrity of this system is to toally discontinue electric service to some of our customers.

Again in 1970 the Company experienced power shortages even though it had planned to increase its capacity resources from 8,882 megawatts to 9,839 megawatts. This would have represented a reserve of 27% of anticipated peak load, and was to be principally achieved by the addition of almost 1,200 megawatts of gas turbine capacity to the system. Construction and start-up delays, as well as a strike which affected one of Con Edison's suppliers, caused slippage in the schedule for adding the gas turbines. The summer, therefore, started with none of the new gas turbines in operation. They came into operation at various times thereafter, and Con Edison had 874 megawatts in operation at the end of the summer. This together with equipment deratings and forced outages, made it necessary for Con Edison to make appeals again for the conservation of electricity by the public and to institute voltage reductions on fifteen days. On one occasion Con Edison had to resort to discontinuance of service to approximately 1% of its customers. Discontinuance of service to any customers is a drastic measure, and every effort must be made to avoid its recurrence.

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* "Deratings" result from equipment problems which, while they do not require that a generating unit be completely removed from service, restrict its operation to less than its full capacity.

**Voltage reductions in excess of 8% would cause damage to customers' equipment.

3.2 Release of Waste Gas Storage Tank Contents

With the assumption that 100% of the decay tank is released, the radiological consequences of this accident are four times those of the corresponding accident in 3.1 above, or 0.6 mRem gamma whole body dose and 0.84 beta skin dose to an individual at the site boundary. Such a dose yields an environmental consequence of 0.7 Man-Rem.

3.3 Release of Liquid Waste Storage Tank Contents

As was the case for 3.2, the radiological consequences of this accident are four times the inhalation dose estimated for 3.1 above, or 0.052 mRem to the thyroid.

Class 4 — Fission Products to Primary System:

This class of accident is applicable only to boiling water reactors.

Class 5 — Fission Products to Primary and Secondary Systems:

5.1 Fuel Cladding Defects and Steam Generator Leak

These releases are included and evaluated under routine releases in accordance with proposed Appendix I to 10CFR50. Such an evaluation is discussed in Section 14 of this Environmental Report.

5.2 Off-Design Transients that Induce Fuel Failures Above Those Expected and Steam Generator Leak

The radiological effects of this transient have been calculated under the assumptions that it would take the operator ten full minutes after the transient began to take the correct action and that it would take six hours before releases due to the transient were terminated. A total inhalation dose to the thyroid of 6.7×10^{-4} mRem is estimated for an individual at the site boundary. The gamma whole body dose at the site boundary after the transient would be about 0.0043 mRem and the beta skin dose would be about 0.0029 mRem. The environmental consequence of this accident has been calculated to be <.001 Man-Rem.

5.3 Steam Generator Tube Rupture

The radiological effects of the steam generator tube rupture have been calculated under the same time dependent assumptions described above in 5.2. The inhalation dose to the thyroid is estimated to be 1.52 mRem at the site boundary. The gamma whole body dose and beta skin dose were calculated to be 15 mRem and 18 mRem, respectively. The environmental consequence of this type of accident is 165 Man-Rem.

Class 6 — Refueling Accidents:

6.1 Fuel Bundle Drop

With a containment volume leak rate of 0.1% per day, calculations show that the radiological effects of this accident are an inhalation dose of 0.0007 mRem, a gamma whole body dose of 8.1×10^{-5} mRem and a beta skin dose of 1.1×10^{-4} mRem. The environmental consequence of this accident is $<.001$ Man-Rem.

6.2 Heavy Object Drop Onto Fuel in Core

From this accident, again in containment, an inhalation dose of 0.012 mRem has been calculated. The gamma whole body dose would be about 1.4×10^{-3} mRem and the beta dose to the skin would be about 2.0×10^{-3} mRem. The environmental consequence of the accident would be less than < 0.001 Man-Rem.

Class 7 — Spent Fuel Handling Accident:

7.1 Fuel Assembly Drop in Fuel Storage Pool

The inhalation dose to the thyroid for an individual at the site boundary was calculated to be 0.17 mRem from this accident after a two-hour period. The gamma whole body dose is estimated at 1.0 mRem and the beta skin dose at 1.4 mRem. The environmental consequence of this accident is 2 Man-Rem.

7.2 Heavy Object Drop Onto Fuel Rack

For this accident, a two-hour inhalation dose of 0.29 mRem was calculated. The gamma whole body dose was calculated to be 1.8 mRem and the beta skin dose to be 2.6 mRem. The environmental consequence of this accident is 5 Man-Rem.

7.3 Fuel Cask Drop

With seven assemblies in one cask, the effects of this accident were calculated to be 0.1 mRem inhalation dose to the thyroid and an additional 0.014 mRem gamma whole body dose and 0.02 mRem beta skin dose. The environmental consequence of this accident is less than < 0.001 Man-Rem.

Class 8

8.1 Loss-of-Coolant Accidents

After a loss-of-coolant accident, containment isolation would occur within one minute of the accident. After this time, the inhalation dose to an individual on the site boundary from a small pipe break would be 0.0004 mRem. From a large pipe break, this dose would be about 3.5 mRem. A containment leak rate of 0.1% of the volume per day was assumed for this initial minute. The gamma whole body dose was calculated to be 3.6×10^{-6} mRem and 5.7×10^{-3} mRem for the small and large pipe breaks, respectively. The beta skin doses for these breaks were calculated to be 4.6×10^{-6} mRem and 2.9×10^{-3} mRem, respectively. The environmental consequence of such an accident is less than < 0.001 Man-Rem.

8.1 (a) Break in Instrument Line from Primary System that Penetrates the Containment

This accident is not applicable to Indian Point Unit No. 3.

8.2 (a) Rod Ejection

After this accident, containment will be isolated within one minute. The inhalation dose from this accident was calculated to be 0.35 mRem at the site boundary. The gamma whole body dose and beta skin dose were calculated to be 5.7×10^{-4} mRem and 2.9×10^{-4} mRem, respectively. The environmental consequence of this accident is less than < 0.001 Man-Rem.

8.2 (b) Rod Drop Accident

This class of accident applies only to boiling water reactors.

8.3 Steamline Breaks Outside Containment (PWR)

The total effect of this accident, based on a large break, would be releases such that, at the site boundary, the inhalation dose to the thyroid would be expected to be 0.054 mRem, the gamma whole body dose would be 4×10^{-5} mRem, and the beta skin dose would be 9×10^{-6} mRem. The environmental consequences of such an accident would be less than 0.001 Man-Rem.

TABLE — 19-1

RADIOLOGICAL CONSEQUENCES OF POSTULATED ACCIDENTS

Accident Class		Thyroid Dose (m Rem)	Whole Body Dose (m Rem)		Man-Rem
			γ	β	
2	Small Releases Outside Containment	*	*	*	*
3	Radwaste System Failure				
3.1	Equipment Leakage or Malfunction	0.013	0.15	0.21	<.001
3.2	Release of Waste Gas Storage Tank Contents	NA	0.6	0.84	<.001
3.3	Release of Liquid Waste Storage Tank Contents	0.052	NA	NA	NA
4	Fission Products to Primary System	NA	NA	NA	NA
5	Fission Products to Primary and Secondary System				
5.1	Fuel Cladding Defects and Steam Generator Leak	*	*	*	*
5.2	Off-Design Transients that Induce Fuel Failures Above Those Expected and Steam Generator Leak	<.001	0.004	0.003	<.001
5.3	Steam Generator Tube Rupture	1.52	15	18	0.04
6	Refueling Accidents				
6.1	Fuel Bundle Drop	<.001	<.001	<.001	<.001
6.2	Heavy Object Drop Onto Fuel in Core	0.012	0.0014	0.002	<.001

TABLE — 19-1

(Cont'd)

Accident Class			Thyroid Dose (mRem)	Whole Body Dose (mRem)		Man-Rem
7		Spent Fuel Handling Accident		γ	β	
	7.1	Fuel Assembly Drop in Fuel Storage Pool	0.17	1.0	1.4	<.001
	7.2	Heavy Object Drop Onto Fuel Rack	0.29	1.8	2.6	<.001
	7.3	Fuel Cask Drop	0.1	0.014	0.02	<.001
8		Accident Initiation Events Considered in Design Basis Evaluation in the Safety Analysis Report				
	8.1	Loss-of-Coolant Accident				
		Small Pipe Break (Less than 6")	<.001	<.001	<.001	<.001
		Large Break	3.54	0.006	0.003	<.001
	8.1a	Break in Instrument Line from Primary System that Penetrates the Containment	NA	NA	NA	NA
	8.2a	Rod Ejection	0.35	<.001	<.001	<.001
	8.2b	Rod Drop Accident (BWR)	NA	NA	NA	NA

TABLE — 19-1

(Cont'd)

Accident Class		Thyroid Dose (mRem)	Whole Body Dose (mRem)		Man-Rem
8.3	Steamline Breaks Outside Containment (PWR)		γ	β	
	Small Pipe Break (6" or Less)	.011	<.001	<.001	<.001
	Large Pipe Breaks	0.054	<.001	<.001	<.001

NOTES: * Within Limits of Proposed Appendix I to 10CFR50

NA Not Applicable to Indian Point Unit No. 3

In 1971, Con Edison added 624 megawatts of additional gas turbine capacity and, after re-rating some of its older units, it had a reserve installed on its own system equal to only 9% of the estimated peak load. Con Edison has also contracted for 920 megawatts of firm capacity purchases, thus raising the planned reserve to 21%.

This reserve, considering the re-ratings, is of the same order of magnitude as those with which Con Edison faced the summers of 1969 and 1970, and again Con Edison has had to resort to the frequent use of voltage reduction. Through November 30, 1971, Con Edison has reduced voltages on its system on fifteen occasions during the year. Major problems were avoided because forced outages of large units were fewer than in previous years and there were no prolonged hot spells.

19.2 Outlook for 1972

The currently estimated peak load is 8,400 megawatts, and installed capacity, assuming that Indian Point No. 2 is on-line, is expected to be 10,600 megawatts. This includes 400 megawatts from Con Edison's share of Bowline Point Unit No. 1, scheduled to go on-line in July 1972, and 348 megawatts from barge-mounted gas turbines, also scheduled for July 1972. The Company has, in addition, arranged for 395* megawatts of purchased capacity. This will provide a planned reserve of 26.2%. Any delay of those units which are scheduled for service in July 1972 will increase the risk of exposure to peak loads at a time when lower levels of reserve exist.

19.3 Outlook for 1973

Two 600 MW fossil-fueled generating units are being constructed by Central Hudson Gas and Electric (Roseton Nos. 1 and 2) near Newburgh, New York. The first unit is scheduled for service in the Fall of 1972 and the second for the Spring of 1973. Con Edison is a joint owner, with a total share of 480 MW.

Con Edison anticipates a peak system requirement for 1973 of 8,850 MW. If all the new capacity described above should be available, together with two small gas turbines being installed for local area support and with firm purchases of 40 MW and additional

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*Of this, 125 megawatts are from Orange & Rockland's share of the Bowline Point Unit No. 1.

purchases of 490 MW now being arranged for the summer of 1973, Con Edison's planned capacity will be 11,088 MW. This will result in a planned reserve of 2,238 MW or 25.3%.

19.4 Outlook for 1974 and Beyond

Indian Point Unit No. 3 is presently scheduled to be in commercial operation to meet the peak load for 1974. Con Edison's latest evaluation of load growth and prospective power supply indicates that Indian Point Unit No. 3 will represent a significant portion of the capacity which must be maintained in 1974 and future years to assure adequate reliability of service to its customers.

The estimated peak load for 1974 is 9,300 MW, and anticipated installed capacity, assuming that Indian Point Unit No. 3 is on-line, will be 12,307 MW. This includes 800 MW from Con Edison's Astoria No. 6 fossil-fueled generating unit in New York City, two small gas turbines, 40 MW of firm purchased capacity for which the Company has negotiated contracts and another 715 MW of firm purchases for which negotiations are now in progress. It will provide a reserve of 3,007 MW or 32.3%, which will represent adequate reserves to prevent a recurrence of the difficulties which have been encountered since 1969 and allow retirement of older, less reliable generating units which contribute heavily to New York City air pollution.

Without Indian Point Unit No. 3 in service in 1974, anticipated installed capacity will be reduced to 11,342 MW, equivalent to a reserve of only 2,042 MW or 22.0%. This would not be significantly greater than the reserves which have been maintained to date and which have proven inadequate to the needs of the system.

It must be kept in mind that another major unit is scheduled for 1974. The Astoria No. 6 Generating Unit is on a tight construction schedule and is threatened with delay by intervenors in the permit process involving environmental hearings.

If Indian Point Unit No. 3 and Astoria No. 6 were both delayed, the anticipated capacity for the Summer of 1974 would be only 10,542 MW, which provides a reserve of 1,242 MW or 13.4%. Con Edison believes that the public interest requires an end to recurring power crises. That end will come in 1974 if Indian Point Unit No. 3 and the other units referred to are in operation by that date.

19.5 Need to Replace Obsolete Facilities

In addition to meeting the requirements of load growth, the availability of planned new capacity including Indian Point Unit No. 3, is essential to allow the retirement of units which are now 40 to 50 years old and which would have already been removed from service were it not for delays already experienced. These units are inefficient and environmentally undesirable. Because of their inefficiency, they emit substantially more pollutants per MWH than more modern fossil fueled plants. Indian Point Unit No. 3 will not, of course, emit such pollutants.

Moreover, despite substantial expenditures for maintenance, they provide a much less reliable source of capacity than that provided by the newer units, and their reliability has continued to deteriorate. Any delay in the operation of Indian Point Unit No. 3 by relying on the deferral of the retirement of these units scheduled for retirement would be ill-advised because these old units will be unable to provide dependable output when required. A total of 1,438 MW, including three complete generating stations and miscellaneous capacity at five other stations, are planned for retirement through 1974.

19.6 New York Power Pool

Con Edison is a member of the New York Power Pool (NYPP) which membership includes the eight major operating utilities in New York State (see Table-4). Indian Point Unit No. 3 will substantially contribute to the reliability of operation of the New York Power Pool.

The forecasted electric supply situation for the New York Power Pool prepared in September 1971 indicates that New York Power Pool reserves in 1974, with Indian Point Unit No. 3 and Astoria Unit No. 6 in service, will be 6,180 MW or 27.5% of estimated co-incident peak load. If Indian Point Unit No. 3 were not in service this reserve would be reduced to 5,215 MW or 23.2%. This would represent a substantial reduction in New York Power Pool installed reserves and a corresponding reduction in the reliability of the Pool.

Under the rules of the New York Power Pool, each company is required to secure sufficient capacity to meet its needs including purchases of firm power. Pool resources are available for emergencies, but cannot be used as a substitute for necessary capacity additions.

19.7 Consequences of Delay

In the event an operating license for Indian Point Unit No. 3 is not obtained, Con Edison will use its best efforts to obtain substitute sources of power for 1974 and, over the long term, provide replacement capacity. There are substantial difficulties with all of the potential alternatives and it may be impossible, in the short run, to obtain alternative power. As indicated in the preceding sections (see also Section 24.1), this would lead to a difficult power supply situation.

The emergency procedures which would be implemented in the event of a power shortage have been prescribed by the New York Public Service Commission in Case 25937 (August 3, 1971). In accordance with the Public Service Commission's order, the Company would make every effort to contract for the purchase of supplemental and emergency capacity from neighboring utilities. The availability of such capacity will depend largely upon two factors: the installation of new capacity in neighboring systems and the transmission capability between systems. Since neighboring systems have experienced delays in meeting service dates and outage problems similar to those of Con Edison, this source of power cannot be relied upon. Also, Con Edison's attempts to strengthen the transmission system have experienced delays caused by local opposition along transmission line routes.

If emergency power were not available, the Company would be required, depending on the severity of the power shortage, to institute load conservation measures such as voltage reductions and disconnection of customers. The number of instances in which the public would be inconvenienced by these measures would depend on the magnitude of the forced outages of generating equipment installed on the Con Edison system and the availability of capacity in other utility systems for sale to Con Edison on an emergency basis.

The Public Service Commission in its opinion in Case 25937, after discussing all possible emergency measures, concluded as follows:

> "There can be no doubt, of course, that this great region will face awesome difficulties if Consolidated Edison does not, reasonably soon, acquire additional generating and power import capacity. It is to that solution, however, that all energies should be turned and not to measures that so plainly invite economic disaster."

20.0 TRANSMISSION LINES

The Indian Point Unit No. 3 transmission facilities consist of a truss framed into the Turbo-Generator Building, four tubular steel line structures located on the site and two tubular steel terminal structures in the Buchanan Substation. There are four site-located transmission structures (3 double circuit towers and one single circuit tower) which communicate with the Con Edison electrical system at the Buchanan Substation 2100 feet away. These towers are designed to carry 345kv output from Indian Point Unit No. 3 and 138kv input for Indian Point Unit No. 3 light and power facilities or the 138 kv output from Indian Point Unit No. 1.

The tubular steel structures with upswept crossarms, as illustrated in Figure-47, were utilized for this connection in order to maintain aesthetic acceptance and environmental compatibility. The structures provide the minimum effect on the landscape, do not interfere with the operation at the plant, or public land use, cross only one public road, as shown in Figure-2 of this report, and will be installed under controlled clearing and construction procedures. A schematic diagram of the route taken by these transmission lines is given in Figure-48. Figure-49 is a schematic of the ring bus at the Buchanan substation.

The structure type was an integral part of the total Indian Point - Buchanan site development. This development was submitted to the Hudson River Valley Commission for review, comment and approval. The HRVC together with the Village of Buchanan gave their approval of the alignment, structure type, and design and installation procedures.

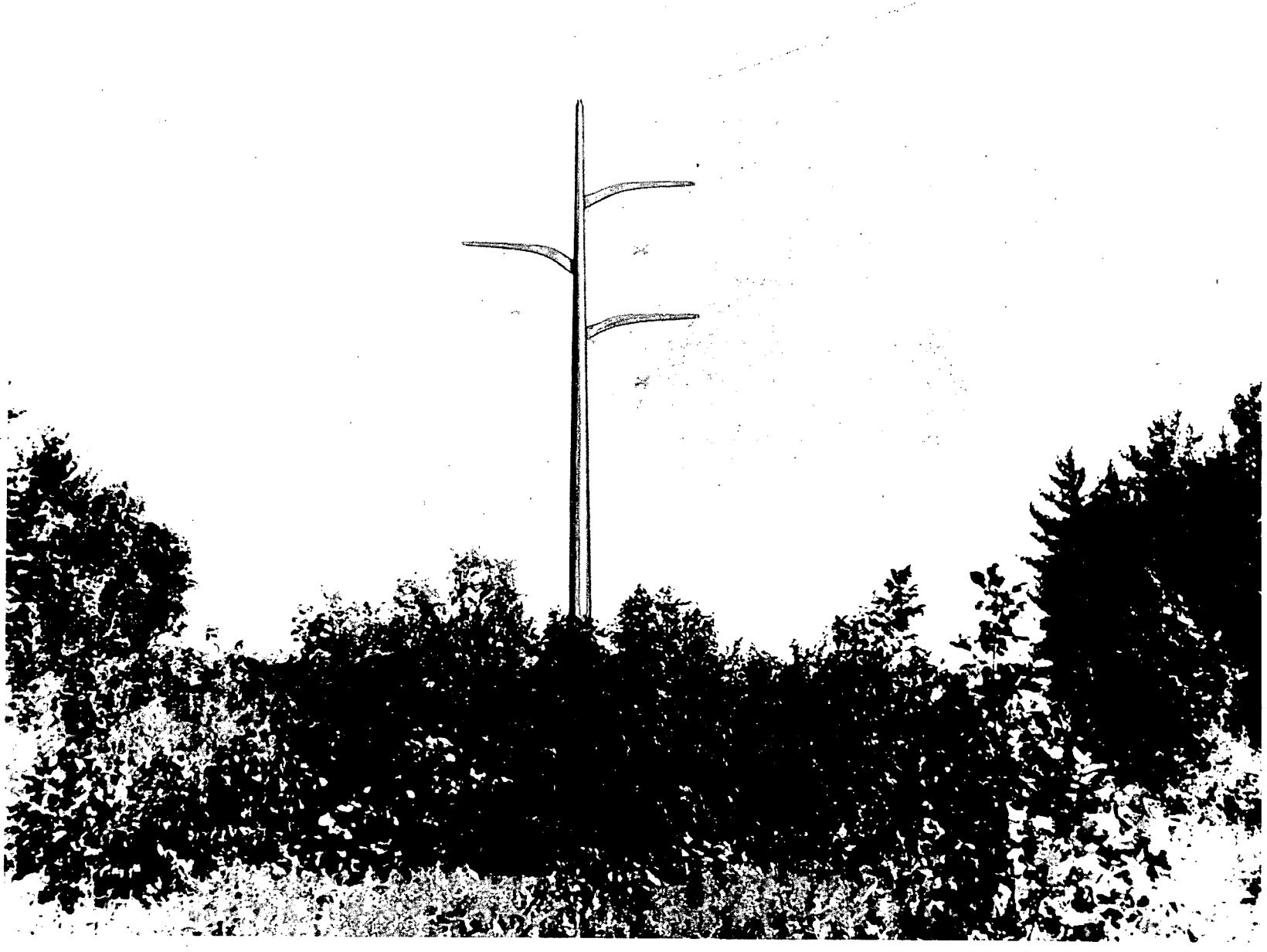

Figure 47. New steel transmission pole.

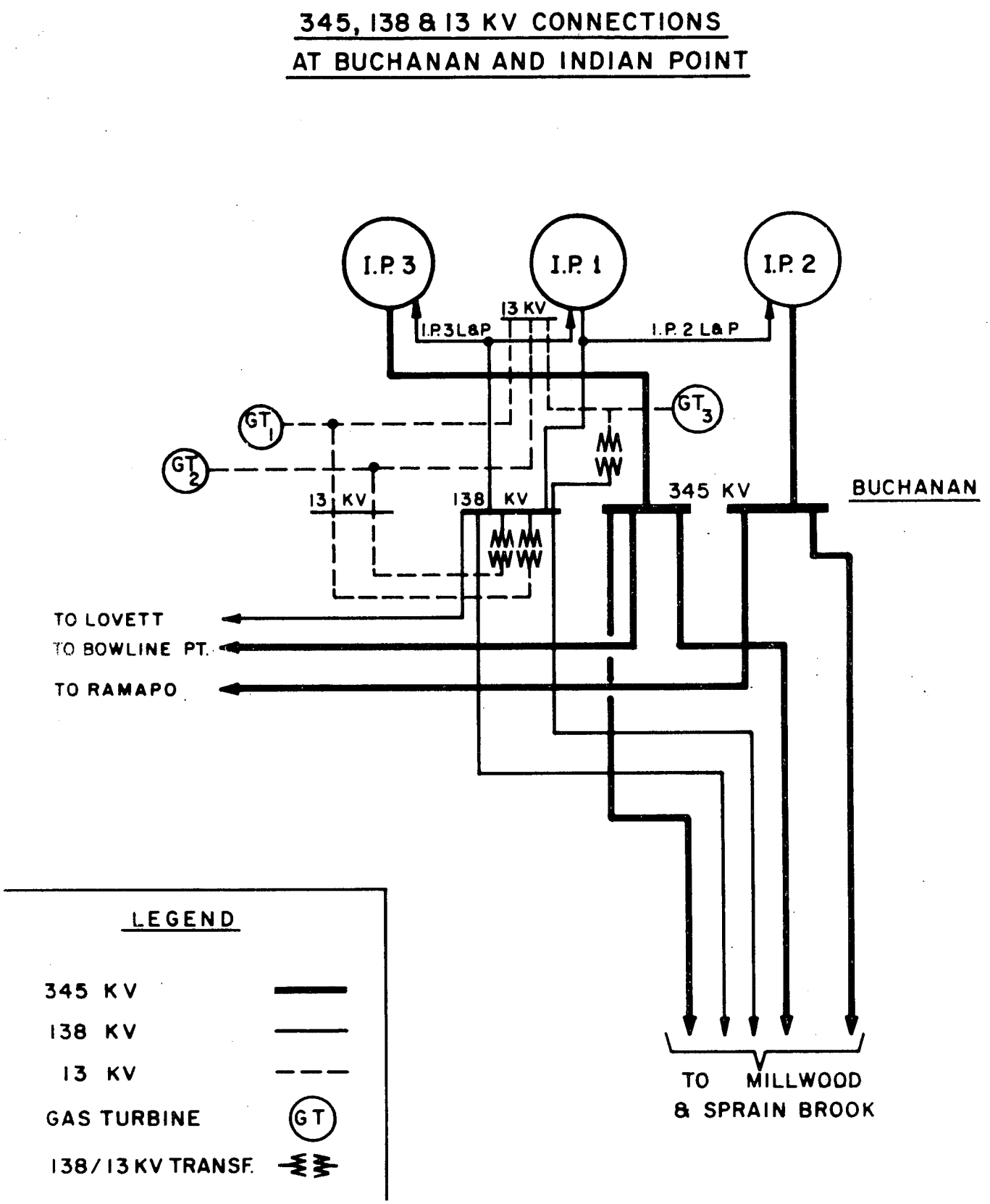

Figure 48 Route of transmission line in the Indian Point-Buchanan area.

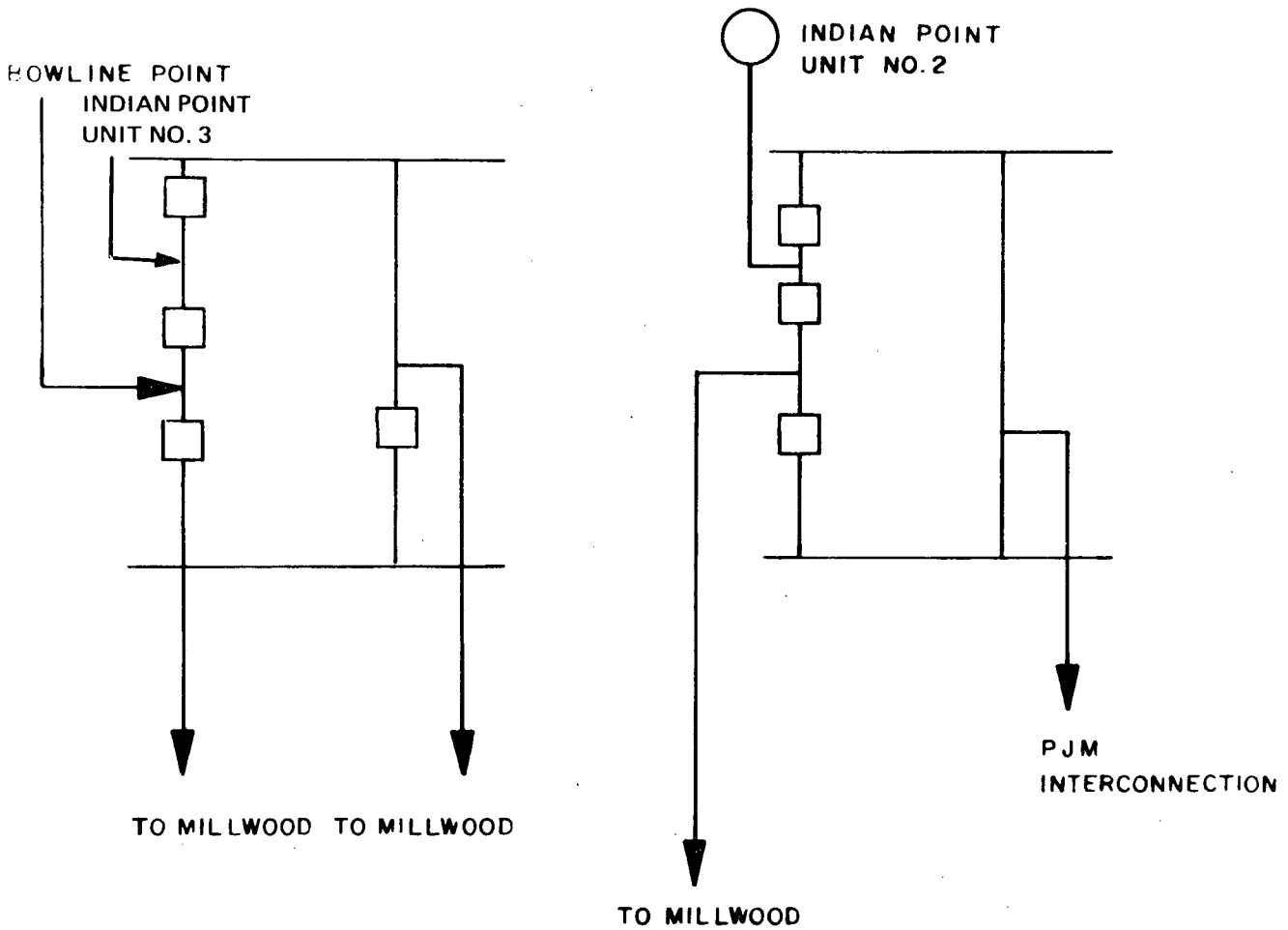

Figure 49 Schematic of ring busses at Buchanan substation.

21.0 TRANSPORTATION OF RADIOACTIVE MATERIALS

General

This section discusses the requirements for transporting new fuel, spent fuel and radioactive wastes to and from the reactor site. In all cases, the shipper will be responsible for securing the necessary licenses for the shipping containers and casks used to transport radioactive material. These containers and casks will be licensed by the fabricator to meet all regulatory requirements, where applicable for the transport of radioactive material, as stated in the Atomic Energy Commission (AEC) Regulations, Part 71 (10CFR71), Subpart C and the Department of Transportation (DOT) Regulations, Part 173 (49CFR173), Subpart G. These standards shall be maintained under the normal conditions of transport, Appendix A of 10CFR71 and Section 173.398(b) of 49CFR173, and the hypothetical accident conditions, Appendix B of 10CFR71 and Section 173.398(c) of 49CFR173.

These conditions are intended to assure that the type of package used, has requisite integrity to meet all conditions which may be encountered during the course of transportation. The normal shipping conditions require that the package be able to withstand such conditions as temperatures ranging from -40°F to +130°F, vibration, shocks and wetting incident to normal transport, without the release of any radioactive material. The accident conditions applicable to new fuel and spent fuel shipments for which the package must be designed include, in sequence, a 30-foot free fall onto a completely unyielding surface, a 40-inch drop onto a six-inch diameter bar, 30 minutes exposure to an environment of 1475°F, and for fissile material, eight hours immersion in three feet of water.

These accident test conditions which must be met are discussed below. New fuel shipping containers and spent fuel shipping casks are referred to collectively as the packages.

(a) Thirty-Foot Free Fall

A 30-foot free fall onto a flat and essentially unyielding horizontal surface. This requires that all the energy of the impact be absorbed by deformation of the package. In addition, the package striking the surface must be in a position for which maximum damage is expected.

(b) Forty-Inch Puncture Test

A free drop through a distance of 40 inches striking, in a position for which maximum damage is expected, the top end of a vertical cylindrical mild steel bar mounted on an essentially unyielding horizontal surface. The bar shall be six inches in diameter, with the top horizontal and its edge rounded to a radius of not more than one-quarter inch, and of such length as to cause maximum damage to the package, but not less than eight inches long. The long axis of the bar shall be perpendicular to the unyielding horizontal surface.

(c) Thermal Test

Exposure to a thermal test in which the heat input to the package is not less than that which would result from exposure of the whole package to a radiation environment of 1475°F for 30 minutes with an emissivity coefficient of 0.9, assuming the surfaces of the package have an absorption coefficient of 0.8. The package shall not be cooled artificially until three hours after the test period unless it can be shown that the temperature on the side of the package has begun to fall in less than three hours.

(d) Water Immersion (fissile material packages only)

Immersion in water to the extent that all portions of the package to be tested are under at least three feet of water for a period of not less than eight hours.

It is unlikely that the new fuel containers and casks will experience conditions as severe as those imposed by the 10CFR71 requirements. Further, since the tests are required to be applied to these packages in sequence, the cumulative severity of these conditions in all probability, far exceeds that to which a container or cask would ever be subjected as a result of an accident during transportation.

Compliance with the above-mentioned regulatory requirements material precludes the release of radioactivity, insures that the contents of the new fuel container or cask remain subcritical and assures package integrity if subjected to a typical highway accident, such as collision with another truck, automobile or stationary object.

21.1 Transportation of New Fuel

In the early years, new fuel will be supplied by Westinghouse from either their Cheswick, Pennsylvania plant or their Columbia, South Carolina plant which are 450 miles

and 800 miles, respectively, from the reactor site. Shipments of new fuel will most likely be made by trailer-truck, with each truck carrying up to seven shipping containers. These containers carry a maximum of two fuel assemblies each. At the present time, the maximum number of new fuel assemblies which can be transported per shipment is fourteen. On the average, future fuel cycles will require about sixty-four new fuel assemblies at approximately one-year intervals; therefore, necessitating about five new fuel shipments per year.

Nuclear material contained in the fuel assemblies is in the form of pellets. Because the fuel has not been irradiated, it does not contain radioactive fission products. Moreover, new fuel requires no coolant during shipment. Compliance to the above conditions of transport precludes the release of radioactive fuel material from the container and insures that the container contents will remain subcritical. For the normal conditions of transport, the container is designed so that the dose rate on its surface shall not be more than 200 millirem/hr, and the dose rate 6 feet from the external surface of the vehicle, shall not be more than 10 millirem/hr. In addition, during the hypothetical accident conditions, the container is designed so that any reduction of shielding would not be sufficient to increase the external radiation dose to more than 1000 millirem/hr at 3 feet from the external surface of the container. Therefore, shipment of new fuel under the normal conditions of transport and the hypothetical accident conditions will result in adherence to the AEC and DOT package standards for the transport of radioactive materials.

21.2 Transportation of Spent Fuel

During the early years of the plant, spent fuel will probably be shipped by a combination of truck and rail. In accordance with a contract executed on September 14, 1971, the shipments will be made to the General Electric Company's Midwest Fuel Recovery Plant (MFRP) at Morris, Illinois. The proposed spent fuel shipping cask will be transported by trailer-truck to a rail siding less than 1.5 miles from the site boundary and shipped the remaining 1000 miles by rail to the MFRP.

Each cask can accommodate a maximum of seven spent fuel assemblies. On the average, future fuel cycles will require the shipment from the plant of about sixty-four assemblies at approximately one-year intervals. This number of assemblies will require about ten spent fuel shipments per year. In future years, it is possible the spent fuel shipments will be made entirely by trailer-truck. Should such a mode of transportation

be used, the capacity of the cask would be at most three assemblies. If this were the case, approximately twenty-two spent fuel shipments would be required annually. Table 21-1 provides a summary of core region replacement and the number of shipments expected per year.

Because the fuel material in the spent fuel assemblies has been irradiated, it contains radioactive fission products. Prior to shipment, the fuel is allowed to decay a minimum of about 100 days so that essentially all noble gases, except Krypton-85, will have decayed away and the Iodine-131 will have decayed away to low levels. Further, the decay heat rate will have diminished such that it amounts to only about 0.1 percent of the heat generation rate of the fuel during reactor irradiation. In addition, spent fuel requires the use of a liquid primary coolant, which typically has been water. Compliance to the normal conditions of transport will insure that the cask contents remain subcritical with no release of radioactive material and no loss of coolant from the cask. For the normal conditions of transport, the cask is designed so that the dose rate on its surface shall not be more than 200 millirem/hr, and the dose rate 6 feet from the external surface of the vehicle shall not be more than 10 millirem/hr. Therefore, shipment of spent fuel under the normal conditions of transport will result in adherence to the AEC and DOT package standards for the transport of radioactive material.

The cask shall be designed and constructed to meet the regulations hypothetical accident conditions applied sequentially, in the following order:

(a) Thirty-Foot Free Fall

Table-18 shows a comparison of the various forces which would be generated by the stopping of the shipping cask, an overweight truck, or an automobile traveling at various speeds upon striking an unyielding surface. As indicated in the table, a 130,000 lb. shipping cask which is equivalent to the GEIF300 traveling at 30 mph, which is the terminal velocity following a 30-foot free fall, would create 7,800,000 pounds of force if stopped within a distance of six inches. A loaded truck, weighing 75,000 lbs. and traveling at 60 mph coming in contact with an unyielding surface is assumed to decelerate within ten feet. Under these condition, the truck would generate a maximum of 900,000 pounds of force, or about 1/8 of the force that would be generated by the 130,000 lb. cask as a result of the

TABLE 21-1

SPENT FUEL ELEMENT SHIPMENTS

Core	Expected No. Elements/Region	Expected No. Shipments/Year*
Indian Point No. 1	40	*6
Indian Point No. 2	64	10
Indian Point No. 3	64	10

*Based on rail shipments with 7 elements per shipping cask

TABLE 21-2

IMPACT ACCIDENT COMPARISON

Object	Weight (Lbs.)	Initial Velocity (MPH)	Stopping Distance (Ft.)	G's	Deceleration Force (Lbs.)
Cask	130,000	30	0.5	60	7,800,000
Truck	75,000	60	10'	12	900,000
Car	5,000	80	5'	44	220,000

30-foot free fall. Likewise, a 5,000 lb. automobile traveling at 80 mph and then hitting an unyielding surface is assumed to stop in only five feet. This deceleration would generate about 220,000 pounds of force. Thus, it is seen that typical objects which the shipping cask might encounter would generate substantially less force upon the cask than the tested force because of the relatively weaker sections of their structures and the greater distance required to decelerate those bodies.

Shipping cask collision with stationary objects such as bridge abutments, etc., has also been considered. In this regard, it should be noted that even heavily loaded trucks contacting such stationary objects generally severely damage the object and displace it by some measurable amount. Therefore, these stationary objects generally, cannot be considered as unyielding surfaces. As demonstrated in Table 21-2, the force developed by the shipping cask impacting on an unyielding surface is greater than that developed between the cask and a "stationary object". Thus, the damage that would be experienced by the cask in hitting a stationary object is less than the damage that would occur as the result of a 30-foot free fall because of the "yielding" of the "stationary objects".

Therefore, as a result of these conditions and the ruggedness of the cask, the possibility of encountering a transportation accident of sufficient severity to approach the test condition is exceedingly small.

(b) Forty-Inch Puncture Test

In regard to the relationship of this test to possible conditions expected during transportation, it was originally intended that the six-inch diameter pin would approximate the end of a rail for a rail transportation accident. It should be noted that the puncture so specified would require that the cask hit the pin exactly perpendicular to the cask surface. Any deviation from this would result in a substantially reduced loading on the side of the cask and enhance chances of deflection. Further, the pin must be long enough to penetrate through the walls of the cask, which would be required for damage to the contents. In most cases, this would require that the pin be approximately 12 to 18 inches in length. However, if the pin is much longer than this, it becomes doubtful that the column strength of the pin is sufficient to rupture the cask without buckling of the proposed pin.

TABLE-17

SPENT FUEL ELEMENT SHIPMENTS

Core	Expected No. Elements/Region	Expected No. Shipments/Year*
Indian Point No. 1	40	*6
Indian Point No. 2	64	10
Indian Point No. 3	64	10

*Based on rail shipments with 7 elements per shipping cask

TABLE-18

IMPACT ACCIDENT COMPARISON

Object	Weight (Lbs.)	Initial Velocity (MPH)	Stopping Distance (Ft.)	G's	Deceleration Force (Lbs.)
Cask	130,000	30	0.5	60	7,800,000
Truck	75,000	60	10'	12	900,000
Car	5,000	80	5'	44	220,000

30-foot free fall. Likewise, a 5,000 lb. automobile traveling at 80 mph and then hitting an unyielding surface is assumed to stop in only five feet. This deceleration would generate about 220,000 pounds of force. Thus, it is seen that typical objects which the shipping cask might encounter would generate substantially less force upon the cask than the tested force because of the relatively weaker sections of their structures and the greater distance required to decelerate those bodies.

Shipping cask collision with stationary objects such as bridge abutments, etc., has also been considered. In this regard, it should be noted that even heavily loaded trucks contacting such stationary objects generally severely damage the object and displace it by some measurable amount. Therefore, these stationary objects generally, cannot be considered as unyielding surfaces. As demonstrated in Table-18, the force developed by the shipping cask impacting on an unyielding surface is greater than that developed between the cask and a "stationary object". Thus, the damage that would be experienced by the cask in hitting a stationary object is less than the damage that would occur as the result of a 30-foot free fall because of the "yielding" of the "stationary objects".

Therefore, as a result of these conditions and the ruggedness of the cask, the possibility of encountering a transportation accident of sufficient severity to approach the test condition is exceedingly small.

(b) Forty-Inch Puncture Test

In regard to the relationship of this test to possible conditions expected during transportation, it was originally intended that the six-inch diameter pin would approximate the end of a rail for a rail transportation accident. It should be noted that the puncture so specified would require that the cask hit the pin exactly perpendicular to the cask surface. Any deviation from this would result in a substantially reduced loading on the side of the cask and enhance chances of deflection. Further, the pin must be long enough to penetrate through the walls of the cask, which would be required for damage to the contents. In most cases, this would require that the pin be approximately 12 to 18 inches in length. However, if the pin is much longer than this, it becomes doubtful that the column strength of the pin is sufficient to rupture the cask without buckling of the proposed pin.

It should be noted that the casks are required to pass the puncture without rupture of even the outer shell. As generally, there is a heavy outer shell backed up by several inches of shielding material followed by an inner steel shell, the damage that the cask would sustain as a result of the required puncture test is less than that which would be required to rupture the inner vessel such that there could be dispersal of the radioactive contents. Thus, this test is representative of those to which a cask would be subjected as a result of a transportation accident.

(c) Thermal Test

During this accident condition, the cask will most likely be lying on the ground near the cooler part of the flames such that it is not surrounded completely by the fire environment. Further, while there may be individual flame temperatures hotter than the proposed 1475°F, the average flame temperatures will not exceed these values. The proposed test conditions in the regulations provide adequate simulation of the fire conditions to which a cask might be accidentally subjected during the course of transportation.

(d) Water Immersion

Under this hypothetical accident condition, the contents of the cask will remain subcritical because of the presence of fixed neutron absorbing material and non-optimal geometry. Thus, accidental criticality is precluded.

Compliance to the hypothetical accident conditions will insure that the cask contents remain subcritical with no release of radioactive fuel material. For the hypothetical accident conditions, the cask is designed so that any reduction of shielding would not be sufficient to increase the external radiation dose to more than 1000 millirems/hr at 3 feet from the external surface of the cask. Therefore, a shipment of spent fuel subjected to the hypothetical accident conditions will result in adherence to the AEC and DOT package standards for the transport of radioactive material.

The hypothetical accident conditions which must be met will assure the integrity of the cask if subjected to a typical highway accident, such as collision with another truck, automobile or stationary object.

21.3 Transportation of Radwaste to Burial Grounds

Throughout the lifetime of the plant, solid radioactive waste, in the form of spent resins and waste evaporator bottoms, will be packaged and stored in a shielded drumming station storage area until shipment off-site for disposal at a federally approved burial ground. The waste matter is solidified in a mixture of vermiculite and cement in DOT (49CFR173) approved steel drums. After a sufficient number of filled drums have accumulated, they will be shipped by truck to a burial site (presently Morehead, Kentucky). It is estimated that 90 to 150 drums of solid waste will be shipped each year in five to ten shipments.

Before shipment, a health physics technician will field check the drums to be sure that all radiation levels are below the limits set by the Department of Transportation in 49CFR173.393. The dose rate three feet from each drum must be less than 100 mrem/hr. Readings are also taken outside this truck to insure that the dose rates at the surface of the truck, and six feet from the surface of the track are less than 200 mrem/hr and 10 mrem/hr, respectively. A wipe test is also made of each drum to be sure that there is no removable surface contamination. In addition, drums indicating contamination levels above background are not loaded on the truck.

The trucks travel major roads, particularly the interstate highways. Since these highways are larger, have better driving conditions and are more frequently patrolled by policemen, the probability of an accident occurring as well as the probability of an accident going undetected for any considerable length of time is greatly reduced.

The conditions for which the drums are designed would not be exceeded in their transport from Indian Point, New York to the burial site. The test conditions, where applicable as defined by 49CFR173.398, and which must be met, would insure the integrity of the drums during transportation.

BENEFIT-COST DESCRIPTIONS OF ALTERNATIVE PLANT DESIGNS FOR INDIAN POINT UNIT NO. 3

By

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
NEW YORK, NEW YORK

and

BATTELLE
COLUMBUS LABORATORIES

September, 1972

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505 King Avenue
Columbus, Ohio 43201

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BENEFIT-COST DESCRIPTIONS OF ALTERNATIVE PLANT DESIGNS FOR INDIAN POINT UNIT NO. 3

INTRODUCTION

This report has been prepared in connection with the proceeding before the United States Atomic Energy Commission (AEC) in which Consolidated Edison Company of New York, Inc. (Con Edison) has obtained a construction permit and is seeking an operating license for its 965 MW(e) nuclear generating plant, Indian Point Unit No. 3.

This is the third of three nuclear power generating plants planned for the Indian Point site. On April 25, 1967, Con Edison filed its application for licenses for Unit No. 3 with the AEC. On August 13, 1969, the AEC, after a public hearing and after favorable recommendations from the Atomic Safety and Licensing Board as well as the Advisory Committee on Reactor Safeguards issued Construction Permit CPPR-62 for this facility. The present schedule anticipates that the unit will be ready for commercial operation in the second half of 1974.

The data and interpretation contained in this report is intended to provide information to the U.S. Atomic Energy Commission for its development of a benefit-cost analysis which balances the environmental effect of the facility and the alternatives for reducing or avoiding adverse environmental effects as well as the environmental, economic, technical, and other benefits of the facility.

In compiling and organizing the information contained in this report, Con Edison and its contractor, Battelle-Columbus, have, insofar as feasible, followed the AEC "Guide for Submission of Information on Costs

and Benefits of Environmentally Related Alternative Designs for Defined Classes of Completed and Partially Completed Nuclear Facilities" dated May, 1972. The procedures and computational methods set forth in the guide were followed using the considerable biological data, information, and reports available. The results obtained in the form of numbers may provide some information to assist the Commission in evaluating alternative systems; the results may or may not represent the true biological situation. Definitive knowledge of river biota and effects of Unit No. 3 must await a biological analysis based upon additional data. Such an analysis began two years ago and is continuing over the next four years. At the end of that period there are expected to be sufficient observations both before and after startup of Unit No. 3 to permit a scientific evaluation of the biological impact of the unit on the Hudson River. The information presented in this section on thermal discharges and their effects; entrainment of fish eggs and larvae and; the impact on the ecosystem of the Hudson River will be discussed in greater detail in the appropriate sections of the Environmental Report in future supplements now planned for October and November 1972. The environmental costs listed in this report are overestimates of the actual costs that might be expected since the estimates are based on the assumption that the plant operates without interruption throughout the year. There are approximately two months per year devoted to refueling and maintenance activities during which the plant is not operating.

ALTERNATIVES

The AEC guidelines state:

"Alternative A is the design basis for the facility as constructed or planned to date in accordance with its Construction Permit and any amendments thereto. Design changes for which authorization is pending would be properly included in the proposed Alternative C.

"Alternative B is plant design which results in the overall minimal environmental cost. The goal of this alternative is to incorporate the subsystems which result in the least overall environmental cost into the plant's functional design, taking into account terrestrial, atmospheric, aquatic, aesthetic, and safety factors. The full range of commercially available configurations is to be considered and described. This alternative should not be constrained by monetary costs; however, the cost of the resulting combination subsystems must be identified.

"Alternative C is the proposed plant design alternative for which licensing is being requested. This design represents the applicant's best effort to balance environmental costs with the economic costs of their reduction or elimination".

The alternatives selected for compiling benefit-cost information are described in the following paragraphs.

Alternative A, the existing plant, which as of September 1, 1972, is approximately 70 percent complete, is a 965 MW(e) pressurized water reactor utilizing once-through cooling with the condenser discharge water from this facility being mixed with that from Units No. 1 and 2 in the same discharge canal. For a more detailed description of the facility as presently designed, see Section 3.0 of the Environmental Report.

Alternative B was selected as the alternative with a significantly modified environmental effects; it was not found to be possible to characterize one of the various alternatives as that which results in the overall "minimal environmental cost". In reviewing the various alternatives, it was found that each had its advantages and disadvantages with respect to

various environmental effects. While it is possible to compare alternatives in terms of impact for a particular effect, it is not possible to directly compare the overall impact for all the effects, i.e., it is not possible to technologically state that air quality is more important than water quality, or reducing the effect of plant operations on aquatic biota more important than avoidance of visual intrusions on the landscape.

The alternative selected for Alternative B is the present facility with the addition of a natural-draft closed-cycle cooling tower. This alternative was chosen because (1) as a closed-cycle cooling system it has a substantially different environmental effect from Alternative A, and (2) of the alternative closed-cycle cooling systems considered it has the smallest environmental impact from fog, drift, and salt deposition. The water impact is essentially the same for all the closed-cycle cooling alternatives considered. Open-cycle cooling alternatives were not chosen to be covered by this analysis because previous investigations had indicated that these alternatives produced a significantly larger water impact than the closed-cycle cooling alternatives. Both open- and closed-cycle cooling alternatives are discussed in revised Section 17.0 of the Environmental Report.

Alternative C is identical with Alternative A as Con Edison is indeed seeking licensing of this pressurized water reactor system utilizing additional areas and volumes (over Units No. 1 and 2) of the Hudson River for cooling. Taking the necessary steps to further minimize the water impact from Unit 3 introduces other environmental impacts such as fogging, drift, and salt deposition which may not be severe but would be new and unnecessary for the Indian Point community.

Consideration of Radiological Impacts in Formulating Alternatives. The Alternative A design will limit doses from radioactive material in liquid and gaseous effluents to levels that are within the numerical guides for design objectives and limiting conditions of operation set forth in the AEC's proposed Appendix I (dated June 9, 1971) to 10 CFR Part 50. Thus, as suggested in the guide for benefit-cost analyses, no further consideration is given to the reduction of radiological impacts in formu-- lating alternative plant designs for Alternatives B and C, i.e., Alternatives B and C would utilize the same radioactive waste treatment design as Alternative A.

These conclusions are further supported in the additional textual material accompanying the tables and other sections in the Environmental Report.

To facilitate the discussion of the subalternatives the following designations will be used in this report.

Cooling System Subalternative	Designation
Once-Through	AA
Natural-Draft Tower	BB
Mechanical-Draft Towers	BC
Spray Pond	BD

BENEFITS FROM THE PROPOSED FACILITY

1.1 Direct Benefits

Indian Point Unit 3 will have an initial capability of 965,000 kilowatts electrical and a projected economic service life of thirty years. In the determination of the Benefits and Costs of the proposed facility, the plant as currently designed is both Alternative A (Plant As Is) and Alternative C (Plant Operating License Request). Alternative B (Plant with Modified Environmental Impact) includes the installation of a natural draft closed cycle cooling tower.

The expected average annual generation was determined from a study of fuel and operation and maintenance costs for the economic life of the plant. The first five years of energy production is shown below.

	Kilowatthours	Capacity Factor
1974 (June-Dec.)	3,557,000	72.1%
1975	6,187,000	73.2
1976	6,432,000	76.1
1977	5,946,000	70.3
1978	5,946,000	70.3

After the initial five years, average annual production is projected to be approximately 5,950,000 kilowatthours. The variation in energy production during the first three years is due primarily to the varying periods between refueling. Only one of the three fuel core regions is replaced in each scheduled maintenance period. Scheduled maintenance after the third year of operation is estimated to occur once each year and to last for six weeks (1,008 hours).

To provide a conservative estimate of capacity unavailability, a 15% annual forced outage rate and additional allowance of 4% per year for miscellaneous partial deratings or limitations on output was assumed

throughout the life of the plant. In combination with a six-week maintenance period each year, this yields a long-term average annual generation of 5,950,000 kilowatthours. Expressed in terms of average annual capacity factor, this is 70.4% (equivalent to 6,166 hours at 965,000 kilowatts.)

For the Con Edison system, the projected percentage of load by class of customers is as follows:

Commercial and Industrial	53.6
Residential	30.0
Other (Railroad and Govern.)	16.4

These estimates are based on long-range forecasts of sales by class of customer. Con Edison does not keep separate statistics on commercial customers and industrial customers because they are commingled in several of the rate schedules.

1.2 Revenues From Delivered Benefits (Annual)

To determine the annual revenues from delivered benefits, the projected average rate for all customers in 1972 and 1973, 3.76 cents per kilowatthour, was applied to the expected average annual generation.

It should be noted, however, that if estimates of the rates which might exist at the time of initial operation of the plant in 1974 were used in the calculation, the power benefits of the plant would be greater. Similarly, the estimate of annual benefits from the plant would have been greater if the likely increase in rates through the life of the plant had been projected and used to determine levelized annual revenues for that period. Thus, the power benefits were significantly understated since no change in current rates was allowed, even though such changes are likely.

1.3 Indirect Benefits

Taxes

The estimated annual real estate taxes to be paid by the proposed facility are $6,980,000 based on current rates applied to the projected capital cost of the facility.

Air Quality

The operation of Indian Point Unit No. 3 will reduce the adverse environmental impact that would otherwise occur if Indian Point No. 3 were not in operation and the Company were required to make greater use of its fossil-fueled plants. The Company has projected the dispatch of its generating stations which would occur from June 1974 to May 1975, the first year of full operation of Indian Point Unit No. 3, with and without that unit in service. The increase in generation at each station was converted into expected additional emissions of particulates, sulphur dioxide and nitrous oxides.

This analysis was based on all units burning only oil, or gas when available. For steam generating units this is projected to be 0.3% sulphur residual oil: for gas turbines, a mixture of kerosene (0.5% sulphur) and No. 2 oil (0.2% sulphur). The emission of pollutants on the Con Edison System which is avoided with Indian Point No. 3 in service as proposed in Alternative A is expected to be 486 tons per year of particulates, 9706 tons per year of sulphur dioxide and 11,811 tons per year of No_x.

The increased air pollution avoided with Indian Point No. 3 in service would be slightly less for Alternative B than for Alternative A. This is due to the increased generation which would be required of fossil units to replace the energy lost by derating when Indian Point No. 3 is operating with a supplemental cooling system.

Reliability

Con Edison normally performs reliability calculations with a loss of load analysis confined to the times of maximum exposure to the peak load. This is the hour of maximum load for each weekday from June 15th to September 15th. If the capacity availability is less than the load at the peak hour it is counted as a day of loss of load. A loss of load day is one on which the Company cannot meet its peak load with its own generation plus firm purchases. Thus, a loss of load day would occur on any day the Company was forced to use emergency or supplemental purchases or forced to reduce voltage or to actually disconnect customer load. Although supplemental purchases or load curtailment measures may be required to meet operating reserve requirements, these have not been considered in the loss of load calculation.

For 1974, with all units scheduled for the Summer of 1974 including Indian Point No. 3 in service, and with scheduled retirements completed, the loss of load expected would be 1.5 days per summer.

If Indian Point No. 3 is not in service during the Summer of 1974, the expected number of loss of load days will increase to 3.7 days assuming that all other planned new units are available as scheduled, but that planned retirements are deferred. Since the reliability index is

based on 65 summer days, this represents 5.7% of the summer days. Thus, there would be a 2.2 day increase in the expected number of loss of load days without Indian Point No. 3 in the Summer of 1974, even if retirements are deferred. Expressed another way, this means an expected exposure of the system to emergency conditions that would be 246% of the exposure with Indian Point No. 3 in service.

The Con Edison Capacity Program includes another major base load unit which is scheduled for service in 1974 and consequently, Indian Point No. 3 is not the only unit subject to delay. If the second unit, the 800 MW fossil fueled Astoria Unit No. 6 were delayed, the projected reliability of power supply for the Summer of 1974 would be considerably enhanced if Indian Point No. 3 were in service.

If Indian Point No. 3 is in service and Astoria No. 6 is delayed, the expected loss of load would be 3.2 days per summer.

If Indian Point No. 3 also was not in service for the Summer of 1974, the number of loss of load days would increase to 11.2 days per summer, representing 17.2% of the 65 summer weekdays. Thus, there would be a 8.0 days' increase in the expected number of loss of load days without Indian Point No. 3 in the Summer of 1974, if Astoria No. 6 were delayed. Expressed another way this means an expected exposure of the system to emergency conditions that would be 350% of the exposure with Indian Point No. 3 in service.

Environmental Studies

Extensive biological studies are underway which will yield new and considerable information on the biology of the Hudson River and the effect thereon of the Indian Point plants. These studies are described elsewhere in the report. It is believed that the information developed by these studies will be of considerable benefit to the biological community and industry in general and will have application not only at Indian Point but also at many other locations.

B.1.4 Summary of Benefits From the Proposed Facility

Direct Benefits

Expected Average Annual Generation in Kilowatt-Hours	5,95[illegible]	[illegible]
Capacity in Kilowatts		965,[illegible]
Proportional Distribution of Electrical Energy Expected		
Annual Delivery in Kilowatt-Hours:		
Industrial		
Commercial	3,89[illegible]	
Residential	[illegible],795,[illegible]	
Other	975,8[illegible]	
Expected Average Annual Btu (in millions) of Steam Sold from the Facility		0
Expected Average Annual Delivery of Other Beneficial Products (appropriate physical units)		0
Revenues from Delivered Benefits:		
Electrical Energy Generated	223,7[illegible]	
Steam Sold		0
Other Products		0

Indirect Benefits (as appropriate)

Taxes (Local, State, Federal) (Local Real Estate)		6,98[illegible]
Research		
Regional Product		
Environmental Enhancement:		
Recreation		
Navigation		
Air Quality:		
SO_2 (Tons per Year June 1974 To May 1975)		9,[illegible]
NO_x		[illegible],8[illegible]
Particulates		486
Others		
Employment		
Education		
Others		

2.1 Generating Costs for Alternatives A and C

The total capital cost for Indian Point No. 3 is $317,236,000. Estimated expenditures to August, 1972 are $144,335,000. Remaining capital expenditures are $172,901,000 as follows:

1972 (August-December)	$ 5,155,000
1973	$ 18,899,000
1974	$148,847,000

The future worth in 1974 of the remaining capital expenditures was determined to be $175,800,000 and is identified below as C_i. The discount factor was 9.75 percent based on the current incremental cost of debt and current earnings requirements on common equity.

Fuel cost estimates for the first five years are as follows:

1974 (June-December)	$ 8,404,000
1975	$14,002,000
1976	$15,084,000
1977	$11,826,000
1978	$12,413,000

These costs are for the same annual energy outputs as stated in the section on power benefits above. Beginning in 1979 and thereafter, the levelized fuel cost will be $13,011,000 per year for 5,950,000 kilowatthours each year.

The sum of the present worth (1974) of the annual fuel costs for 30 years ($\sum_{t=1}^{T_L} V^t F_t$) is $122,260,000.

Operation and Maintenance cost estimates for the first five years of operation of Indian Point No. 3 are as follows:

1974 (June-December)	$ 750,000
1975	$1,130,000
1976	$1,370,000
1977	$1,720,000
1978	$1,770,000

These costs are for the same annual energy outputs as stated in the section on power benefits above. From 1979 and thereafter, the operation and maintenance costs are estimated to escalate at 5 percent per year.

The sum of the present worth (1974) of the annual operation and maintenance costs ($\sum_{t=1}^{T_L} V^t O_t$) is $21,400,000.

The total generating cost (GC_p) is the sum of the present worth of the additional capital cost, fuel costs, and operation and maintenance costs:

$$C_i = \$175,800,000$$

$$\sum_{t=1}^{T_L} V^t F_t = \$122,260,000$$

$$\sum_{t=1}^{T_L} V^t O_t = \$\ 21,400,000$$

Alternative A: GC_p $319,460,000

2.2 Generating Costs for Alternative B

The modified environmental impact alternative is natural-draft, closed-cycle cooling towers. Construction time for all cooling alternatives was estimated to be three years, starting in 1973 with completion in 1976. Cutover to the alternative cooling system was assumed to be coincident with the annual scheduled maintenance period on the unit with no additional downtime required. This assumption is probably optimistic and, should a longer time actually be required for cutover then, the incremental generating costs for all cooling alternatives are slightly understated.

The plant will be in operation for two years before the alternate cooling system is completed and for this length of time the power benefits and generating costs will be the same as Alternatives A and C. The third year of plant operation will be the first with the alternate cooling system.

The generating costs for the modified environmental impact alternative which has been selected consists of the generating cost for Alternative A plus the "incremental generating cost" for the natural-draft, closed-cycle alternate.

Alternative A - GC_p	= \$319,460,000
Natural-Draft Closed-Cycle Incremental Generating Cost	= \$ 90,460,000
Alternative B: GC_p	\$409,920,000

2.3 Incremental Generating Costs (For Various Alternative Cooling Systems)

For all of the alternative cooling systems considered, the fuel and operation and maintenance expenses associated with Indian Point No. 3 remains the same as in Alternative A even though the output energy from the unit is reduced due to increased back pressure and increased auxiliary requirements of the alternative cooling system. Additional costs are incurred, however, for operation and maintenance of the alternative cooling system itself. This operation and maintenance cost has been estimated and includes an allowance for escalation over the twenty-eight years (assuming three years construction time of which only one year would precede initial plant operation) remaining in plant life. The term "C_c" will designate the sum of the present worth of this additional operation and maintenance cost of the alternate cooling system.

C_i = Sum of the present worth of the capital expenditures for the alternate cooling system. The discount factor (9.75 percent) remains unchanged.

$\alpha = \sum_{t=1}^{T_L} V^t P_t$ = Sum of the present worth of the annual cost of replacement energy. Replacement energy is required because of average annual derating of each alternate cooling system. Energy replaced by Con Edison system at average fuel and operation and maintenance costs for each year starting in 1976.

C_{gt} = The sum of the present worth of the capital expenditures for additional generating capacity necessary to make the plant with an alternate cooling system equivalent to the plant as designed. While the derating of the plant with an alternate cooling system exists all year round, and the lost energy has been taken into account by "α" above, the derating is much higher at the time of the peak ambient temperature. This coincides with the time of Con Edison's expected peak system load. Thus, it is necessary to cover the peak derating with additional installed peaking capacity. This is accomplished by providing for the installation of gas turbines at Indian Point in 1976 at an estimated cost of $167 per Kw. This estimate excludes the cost for additional transmission capacity which would be required if the gas turbines were installed at any site other than Indian Point.

The incremental generating costs for each of the alternative cooling systems follows:

<u>Natural-Draft Closed-Cycle Alternate</u>

Construction Time: 3 years (in service by 1976)

Additional Capital Investment: $58,660,000
(for alternate cooling system only)

Average Annual Derating: 38 MW

Peak Ambient Temperature Derating: 83 MW

C_i = \$53,590,000

O_c = \$ 2,250,000

α = \$23,000,000

C_{gt} = \$11,620,000

Total Incremental Generating Cost:

30-year Sum Present Worth (1974)	\$90,460,000
Annualized	\$ 9,397,000

Mechanical-Draft Closed-Cycle Alternate

Construction Time: 3 years (in service by 1976)

Additional Capital Investment: \$64,310,000
(for alternate cooling system only)

Average Annual Derating: 37 MW

Peak Ambient Temperature Derating: 64 MW

C_i = \$58,750,000

O_c = \$ 7,270,000

α = \$22,000,000

C_{gt} = \$ 8,960,000

Total Incremental Generating Cost:

30-year Sum Present Worth (1974)	\$96,980,000
Annualized	\$10,074,000

Spray Pond Closed-Cycle Alternate

Construction Time: 3 years (in service by 1976)

Additional Capital Investment: \$75,060,000
(for alternate cooling system only)

Average Annual Derating: 46 MW

Peak Ambient Temperature Derating: 86 MW

C_i = \$68,570,000

O_c = \$ 3,260,000

α = \$27,850,000

C_{gt} = \$12,040,000

Total Incremental Generating Cost:

30-year Sum Present Worth (1974)	\$111,720,000
Annualized	\$ 11,605,000

Incremental Environmental Effects

1. NATURAL SURFACE WATER BODY: HUDSON RIVER

1.1 Cooling Water Intake Structure

1.1.1 Fish

Alternative A. Plant As Is

Environmental Cost: 11,200 lb fish/year

Data have been collected daily since April, 1970, on the fish impinged on the screens at Indian Point 1 and there is limited data on the operation of pumps for Indian Point 2. Records of fish impingement at Indian Point indicate that there is a relationship between the numbers of fish impinged on the screens, the velocity and volumes of cooling water flow, the fish density in front of the screens, the water temperature, perhaps the season of the year and the physiological condition of the fish. There are also indications that at low water temperatures, the slight rise in ambient river temperatures in the immediate vicinity of the plant discharge due to the thermal discharge from Indian Point No. 1 may attract fish to the vicinity of the plant discharge. Thus far the interrelationship of these variables has not been determined.

Table 1.1-1 contains estimates of the annual number and weight of fish that would be impinged on the Unit 1 intake screens[1.1a]. These estimates are based on the data obtained from April, 1970, through February, 1972. There are usually interruptions in the plant operation during the year, but the estimates in Table 1.1-1 assume no such interruptions. As such, these values are overestimates of the annual impingement rates.

TABLE 1.1-1. ESTIMATED ANNUAL NUMBER AND WEIGHT OF FISH IMPINGED AT UNIT 1 INTAKE[a]

Species	Number Impinged Annually	Total Weight Annually, lb
White perch	263,614	2142
Striped bass	11,559	159
Atlantic tomcod	30,948	484
Herrings[b]	47,726	597
Bay anchovy	8,203	31
Other	10,813	676[c]
Total	372,863	4089

(a) Includes effect of reduced cooling water flow from October through March as well as full flow operation during the remainder of the year. It also assumes that the plant operates without interruption throughout the year.

(b) Blueback and alewife combined.

(c) Assuming 1 oz each.

In order to estimate the annual impingement rates due to the Unit 3 intake, the Unit 1 estimates were multiplied by the ratio of Unit 3 intake flow (870,000 gpm) to Unit 1 intake flow (318,000 gpm). Thus, the estimate of the total weight of fish impinged on Unit 3 intake screens with Alternative A is 4089 x 870,000 318,000 = 11,183, or about 11,200 lb/year. The estimates by species and for the other alternatives are shown in Table 1.1-2.

In addition, the following items should be considered when evaluating these estimates. The intakes at Ind-an Point No. 3 have been further removed from the thermal influence of the outfall as a result of a new discharge configuration. The faces of the travelling screens are continually washed and the fish are returned promptly to the river. Also, control gates have been installed on the discharge velocity which will improve mixing particularly on the flood tide and reduce temperature differentials in the plume and therefore attract fewer fish to the intake. There is no dock in front of Indian Point No. 3 that may shelter and attract fish. Also, an experimental air bubble curtain was operated at one of the Unit 1 intakes during February, 1971, and it was effective in reducing fish impingement at the test bay. Based on this result, similar curtains are being installed on all of the Unit 1 and 2 intake bays. Measurements will be taken to evaluate the performance of the curtains. If they prove effective on Indian Point 1 and 2, they will be installed on Unit No. 3. As noted above, the intake flow of Unit 3 is approximately 2.7 times higher than Unit 1. The intake velocity at Unit 3 is also 1.5 times higher than Unit 1.

TABLE 1.1-2. ESTIMATED ANNUAL WEIGHTS OF FISH IMPINGED ON UNIT 3 INTAKE SCREENS

Species	Impingement for Each Alternative, lb/year	
	A	BB, BC, BD
White perch	5,858	193
Striped bass	434	14
Atlantic tomcod	1,324	44
Herrings[a]	1,633	54
Bay anchovy	85	3
Other	1,849	60
Total	11,183	368

(a) Blueback and alewife combined.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 400 lb fish/year

The estimate of annual impingement rates for the closed-cycle cooling alternatives was calculated as described under Alternative A. The intake for Unit 3 with the closed cycle alternatives is about 28,700 gpm so that the estimate of the total weight of fish impinged on Unit 3 intake screens with Alternatives BB, BC, or BD is 4,089 x 28,700 318,000 = 368 or about 400 lb/year. The estimates by species are shown in Table 1.1-2.

Alternative C. Plant License Request Design

Environmental Cost: 11,200 lb fish/year

This alternative is identical to Alternative A.

References for Section 1.1

(1.1a) Information supplied by Con Ed

1.2 Passage Through the Condenser and Retention in Closed-Cycle Cooling System

1.2.1 Primary Producers and Consumers

Alternative A. Plant As Is

Environmental Cost: 370 lb fish/year

Experimental data for phytoplankton and microzooplankton relative to this effect have been obtained and projections[1.2a] made for cases of interest. Phytoplanktonic organisms are anticipated to be killed only as a result of chlorination for Alternative A. Chlorine will be used for 1 hr three times a week from late spring through the fall, to clean the condenser tubes, or 42 hr per year (3 hr/wk x 14 wk/year). The average density of phytoplankton in the Hudson River near Indian Point is 4.33×10^4 phytoplankters/cu ft (IP-3 Environmental Report, Appendix R) and the condenser cooling water flow is 1872 cfs (6.739×10^6 cu ft/hr). Thus, 29.18×10^{10} individuals pass through the condenser per hr (4.33×10^4 individuals/cu ft x 6.739×10^6 cu ft/hr). Assuming that all the phytoplankton are killed during chlorination, a total of 1.226×10^{13} phytoplankters/yr are killed. The weight of an individual phytoplankter was estimated to be one nanogram. Calculations on single cells of blue-green algae resulted in an average cell weight of 10^{-11} gm. A nanogram (10^{-9} gm) per phytoplanktonic organism is considered to be a conservative estimate. The total weight of phytoplankters killed annually is 27 lb (1.226×10^{13} individuals/yr x 10^{-9} gm/individual ÷ 454 gm/lb). Samples of microzooplankton consisting of 84 percent adult copepods,

12.2 percent cladocera, 2.7 percent barnacle larvae, and 1.1 percent copepod nauplii were air dried at 50 C and weighed to estimate the weight of an individual microzooplankton. This estimate (1.14×10^{-5} gm) was used to calculate the weight of microplankton killed per year resulting from Alternative A ($1.48 \times 10^{13} \times 1.14 \times 10^{-5}/454.6$). The estimated kill is 3.7×10^{5} lb/yr of microzooplankton. The number of organisms per year estimated to be killed in reference 1.2a is shown in Table 1.2-1. Converting to pounds of fish using a food chain efficiency of 1/1000, about 3.7×10^{2} pounds of fish would be affected annually.

The above costs are reported in conformance with assumptions made in the guidelines. Con Edison studies of phytoplankton and micro-invertebrate zooplankton populations of the Hudson River near Indian Point have indicated that plant operations to date have had no discernible effect on these populations[1.2b].

Alternative B. Modified Environmental Cost Design

Environmental Cost: 33 lbs fish/year

The environmental cost selected for this alternative is that attributed to Subalternative BB, Natural-Draft Closed-Cycle Cooling Tower. Table 1.2-1 is from reference 1.2a, showing numbers of organisms expected to be killed yearly from entrainment. A weight of 3.1×10^{4} lb microzooplankton/year was estimated as described under Alternative A.

TABLE 1.2-1. ESTIMATE OF ORGANISM ENTRAINMENT EFFECTS[1.2a]

	Kills/year (10^{13}) Alternatives		
	AA	BB, BC	BD
Phytoplankton	1.226[a]	71.2	165
Microzooplankton	1.48	0.124	0.288

(a) Calculated as outlined in the text under Alternative A.

A weight of 1570 lb/year of phytoplankton was also estimated as described under Alternative A. These weights are equivalent to about 33 lb of fish per year. The weights for Subalternative BC are identical to Subalternative BB, while the weights for Subalternative BD are 3630 lb/year of phytoplankton and 72,200 lb/year of microzooplankton. These latter weights are equivalent to about 76 lb fish/year.

Alternative C. Plant License Request Design

Environmental Cost: 370 lb fish/year

This alternative is identical to Alternative A.

1.2.2 Fish

The published information on the effect of the passage of fishes and fish larvae through the condensers of a power plant shows such disparate results that it is not possible at this time to predict the effect that Indian Point No. 3 will have in this regard. A study was conducted by Kerr in 1953 on the Contra Costa steam-generating plant near Antioch, California,

on striped bass and small Chinook salmon. The results from these experiments, preliminary tests and other data gathered during the course of this research program indicated that small striped bass and Chinook salmon could pass through the plant with a high survival rate. Studies in England conducted by Markowski indicated that fishes pass through operating condensers with minimum mortalities.

A study conducted in 1971 by Marcy on the Connecticut Yankee atomic power plant on the Connecticut River reported the survival of organisms at three stations along a discharge canal approximately 1.14 miles long. Connecticut Yankee operates at a higher temperature rise than does Indian Point No. 1, No. 2, or No. 3. At these higher temperatures no living larvae or juveniles were taken at the lower end of the canal during the entire experiment. When the canal temperature rose above 95 F, 100 percent mortality occurred at the beginning of the canal.

Temperatures in the Indian Point outfall are not expected to exceed 95 F. Although the temperature increase through the condensers is lower and the retention times are shorter, some mortality associated with the entrainment is expected. However, Con Edison believes it is premature to state a quantitative estimate of survival until it completes a testing program which will establish the rate of survival of these organisms. This program of necessity must be conducted at the time of the year when eggs and larvae are present in the area of Indian Point. This program has been underway throughout the spring and summer months, and Con Edison expects to have sufficient data upon which to base an estimate by late fall.

The environmental cost associated with the relationship of entrained organisms and the population of adult fishes in the Hudson River will be more difficult to obtain. This will require an analysis of many other variables which affect the fish populations of the river.

References for Section 1.2

(1.2a) Personal Communication with Gerald J. Lauer, Ph.D., New York University.

(1.2b) Testimony of Gerald J. Lauer, Ph.D., New York University, on "Effects of Elevated Temperature and Entrainment on Hudson River", before the U.S. AEC in the matter of Consolidated Edison of New York, Inc. (Indian Point Unit No. 2), Docket No. 50-247, April 5, 1972.

1.3 Discharge Area and Thermal Plume

1.3.1 Water Quality, Physical

Alternative A. Plant As Is

Environmental Cost: See Table 1.3-1

The impact for all alternatives is tabulated in Table 1.3-1 along with values that are needed to estimate the impact considered under Item 1.3.3. Values with all units operating with once-through cooling were obtained from analytical hydraulic model studies[1.3a, 1.3b] of the Hudson River near Indian Point. The values for the other combinations presented in Table 1.3-1 were obtained by scaling these data. The values in Table 1.3-1 consist of the heat discharged to the river plus volumes and surface areas bounded by isotherms corresponding to a 2, 3, and 5 F termperature rise as required in the AEC guidelines. Also, since 90 F is considered to be biologically significant and is also a maximum surface temperature permitted by state standards, the cross-sectional area and the surface area within the 90 F isotherm are included in Table 1.3-1 to estimate the impacts considered under Item 1.3.3. The lowest temperature rise to produce a 90 F river temperature is 11 F since the maximum temperature measured in the river at the cooling water intake of the Lovett plant was 79 F[1.3c]. The frequency at which this maximum temperature may occur is about once or twice out of every four years. This temperature (79 F) can be considered to be somewhat higher than the actual ambient river temperature. The QLM studies[1.3b] indicated the maximum surface temperature rise to be about 9.5 f; therefore, 10 F is included for calculation of the river cross-sectional area enclosed by this sub-surface isotherm.

TABLE 1.3.1. HEAT DISCHARGED TO RIVER PLUS VOLUMES, SURFACE AREAS, AND CROSS-SECTIONAL AREAS WITHIN SELECTED ISOTHERMS OF TEMPERATURE RISE

		Subalternative			
		AA	BB	BC	BD
Heat discharged to river 10^9 Btu/hr	Units 1, 2 and 3	15.22	8.43	8.39	8.41
	Units 1, 2, and 3 less Units 1 and 2[a]	6.95	0.16	0.12	0.135

		Subalternative	
		AA	BB, BC, BD
Volume within 2 F acre-ft	Units 1, 2, and 3	3.3×10^4	1.5×10^4
	Units 1, 2, and 3 less Units 1 and 2	2.1×10^4	3.5×10^3
Volume within 3 F acre-ft	Units 1, 2, and 3	1.9×10^4	8.8×10^3
	Units 1, 2, and 3 less Units 1 and 2	1.3×10^4	1.9×10^3
Volume within 5 F acre-ft	Units 1, 2, and 3	7.0×10^3	3.6×10^3
	Units 1, 2, and 3 less Units 1 and 2	3.5×10^3	5.0×10^1
Surface area within 2F acres	Units 1, 2, and 3	1.6×10^3	9.1×10^2
	Units 1, 2, and 3 less Units 1 and 2	6.5×10^2	1.4×10^1
Surface area within 3 F acres	Units 1, 2, and 3	1.2×10^3	6.9×10^2
	Units 1, 2, and 3 less Units 1 and 2	4.9×10^2	1.3×10^1
Surface area within 5 F acres	Units 1, 2, and 3	3.1×10^2	2.1×10^2
	Units 1, 2, and 3 less Units 1 and 2	1.0×10^2	1.0

TABLE 1.3-1. (Continued)

		Subalternative	
		AA	BB, BC, BD
Surface area within 10 F acres	Units 1, 2, and 3[c]	4.7×10^1	4.7×10^1
	Units 1, 2, and 3 less Units 1 and 2[d]	0	0
Cross-sectional area within 10 F ft^2	Units 1, 2, and 3	1.7×10^4	8.9×10^3

(a) Difference of effect when operating Units 1, 2, and 3 less effect when operating Units 1 and 2. This terminology is used rather than state Unit 3 alone to indicate the incremental effects of Unit 3.

(b) The highest ambient river temperature is 79 F. Since 90 F is considered to be biologically significant, the minimum temperature rise that will produce a 90 F temperature is 90 - 79 = 11. Since surface temperature is never expected to reach 90 F, the area within the 10 F temperature rise was considered.

(c) This surface area is in the proximity of the Lovett discharge, where operation at Indian Point has a negligible effect.

(d) The Indian Point plant does not have a 10 F surface isotherm.

The scaling rules for estimating the values for conditions other than all three units operating with once-through cooling are based on theoretical studies with simple momentum jets[1.3d] which indicate that the ratio of initial temperature rise to a specified temperature rise is one of the principal parameters in determining the volume of water and surface area enclosed within the specified temperature rise. Another important parameter is the width or diameter of the jet orifice which is usually considered proportional to the square root of the jet cross-sectional area. In order to arrive at the correct scaling rule, data from an undistorted hydraulic model[1b] were plotted as a function of the ratio of temperature rise. Data from a mathematical jet model, as reported by QLM[1.3e] were also plotted. These plots and the theoretical studies indicated that the volume scaling should be approximately proportional to the square of the temperature ratio and the 3/2 power of the jet cross-sectional area at the lower values of temperature rise, i.e., the area of interest. The surface area and cross-sectional area are also scaled with the product of the square of the temperature ratio and the jet cross-sectional area at the lower values of temperature rise. Since the discharge ports are adjusted to maintain a relatively constant discharge velocity (about 10 fps), the cross-sectional area is proportional to the volumetric discharge rate.

The anchor values for the scaling of Units 1 and 2 acting alone or with the alternate cooling system for Unit 3 were obtained from the most severe set of conditions, as delineated above. These are a condenser temperature rise of 14.8 F, a freshwater flow of 20,800 cfs, and a cooling water flow of 2.06×10^6 gpm. These conditions give a maximum volume and

surface area within given isotherms in the QLM studies. Also, this temperature rise and cooling water flow are close to the values expected for the combined operation of Units 1, 2, and 3 with once-through cooling. The isotherms in the QLM study include the influence of the Lovett and Bowline Plants; that is, the volume and area values given in Column AA of Table 1.3-1 include contributions from these effluents to the thermal plume. The 2 and 3 F isotherms from the Indian Point and Lovett streams coalesce near midstream, while all higher temperature isotherms are distinct. In fact, the Lovett plant has a 10 F surface isotherm, while the Indian Point Units do not. Hence, all scaling operations above 3 F were performed only on the Indian Point effluent--the contribution from Lovett was then added on, thus giving the net effect on the river.

The values chosen from Table 1.3-1 to represent the environmental costs under Item 1.3 were selected with the consideration that Units 1 and 2 will be operating with once-through cooling regardless of the method of operating Unit 3. Therefore, the values selected correspond to the incremental effects of operating Unit 3 over and above the effects of operating Units 1 and 2 alone. Thus, 6950 x 10^6 Btu/hr would be discharged to the present discharge canal from Alternative A for Indain Point 3. Units 1 and 2 also use this canal, discharging another 8270 x 10^6 Btu/hr. The total volume encompassed within the isotherm corresponding to a 5 F temperature rise is 7.0 x 10^3 acre-ft, of which 3.5 x 10^3 acre-ft is the incremental volume attributed to Unit 3.

Additional model results, both thermal and hydraulic, will be presented in Supplement 3 to the Indian Point Unit No. 3 Environmental Report planned for October 1972. Descriptions of the modeling techniques will be included.

Alternative B. Modified Environmental Cost Design

Environmental Cost: See Table 1.3-1

Table 1.3-1 lists the estimated heat inputs and volumes for all the various subalternates evaluated for Alternative B. The procedures employed were as described above for Alternative A and these were repeated three times for the various subalternatives: BB--Natural-Draft Cooling Towers, Closed-Cycle; BC--Mechanical-Draft Cooling Towers, Closed-Cycle; and BD--Spray Pond, Closed-Cycle. The values chosen to represent the environmental cost for Alternative B, Minimum Environmental Cost Design, are those for Subalternative BB. The quantity of heat to be introduced is small compared to the heat being dissipated from Units 1 and 2. The surface areas and volumes within the isotherms of 2, 3, and 5 F temperature rise that could be attributed to Unit 3 are small for all the subalternatives. Since the water impact is identical for all the subalternatives, the selection of the natural-draft cooling tower suboption to represent Alternative B was based upon less potential for ground fog and salt deposition caused by drift from the spray pond or mechanical-draft towers.

Alternative C. Plant License Request Design

Environmental Cost: Same as Alternative A

This alternative is identical to Alternative A.

1.3.2 Oxygen Availability

All Alternatives

Environmental Cost: 0 acre-feet

Studies made on the loss of dissolved oxygen due to the operation of the Indian Point station indicate the loss decreases as the ambient level of dissolved oxygen decreases[1.3f]. For an ambient river level of 6.5 ppm (during summer conditions when the ambient temperature is 79°F), the in-plant loss is less than 0.17 ppm and the loss to the river is less than 0.02 ppm. At lower ambient values of dissolved oxygen, the in-plant losses and the corresponding river losses would be even smaller. Therefore, no loss in dissolved oxygen is expected during those few times when the ambient river level is less than 5 ppm.

1.3.3 Aquatic Biota

All Alternatives

Environmental Cost: 0

Studies to date at Indian Point and at many other power plants indicate that the environmental cost from the discharge of heated water will be zero. Studies for Con Edison by Ichthyological Associates showed that fish can avoid areas of unsuitably high temperatures and therefore no loss of fish will occur. The outfall structure is designed so that the thermal discharge is rapidly entrained with ambient riverwater and that temperatures adequate for the protection of aquatic life including plant shutdown will not be exceeded. It's discharge port velocity will prevent entrance of fish to the discharge canal. The discharge is common to three plants thus precluding, except under black out conditions, any sudden temperature change in the discharge canal or thermal plume.

1.3.4 Wildlife

All Alternatives

Environmental Cost: 0 acres

The thermal plume, even with once-through cooling, is not expected to impair any wetland or water-surface habitats in the Hudson River near Indian Point. The discharge system used in all subalternatives will discharge the bulk of the heated water away from the shallow, slow-moving water habitats near the shores which are most likely to be used by wildlife.

1.3.5 Fish, Migration

All Alternatives

Environmental Cost: 0

In all cases under consideration, the anticipated plumes leave a substantial passing zone adequate for fish migration of the river at Indian Point. Areas for fish passage will be available both in the channel and along the shallow west shore. Fish passage (for species found in the Hudson River) has been well documented for a power plant on the Connecticut River where proportionally a more extensive thermal plume exists.

References for Section 1.3

(1.3a) Testimony of John P. Lawler, April 5, 1972, AEC Docket No. 50-247.

(1.3b) Information supplied by Consolidated Edison.

(1.3c) Testimony of John P. Lawler, Transcript of Hearing on Indian Point Unit No. 2. Session of January 11, 1972, p. 4426, AEC Docket No. 50-247.

(1.3d) D. W. Pritchard, "Design and Siting Criteria for Once-Through Cooling Systems". Paper No. 266 presented to 68th National Meeting of the American Institute of Chemical Engineers at Houston, Texas, March 2, 1971.

(1.3e) "Effect of Submerged Discharge of Indian Point Cooling Water on Hudson River Temperature Distribution", Report of Quirk, Lawler, and Matusky Engineers to Consolidated Edison Company of New York, Inc., October, 1969. (Appendix L of Indian Point Unit 3 Environmental Report.)

(1.3f) "Effect of Indian Point Plant on Hudson River Dissolved Oxygen", Report of Quirk, Lawler, and Matusky Engineers to Consolidated Edison Company, February, 1972.

1.4 Chemical Effluents

The chemicals which will be discharged from Indian Point Unit 3 are identified and the amounts to be released are described in the Unit 3 Environmental Report[1.4a]

1.4.1 Water Quality, Chemical

Alternative A. Plant As Is

Environmental Cost: 0 acre-feet, 0 percent

As noted in the Indian Point Unit 3 Environmental Report[1.4a] the Hudson River waters at Indian Point are classified as "Class SB" by New York State, but quality standards are phrased in terms of general criteria rather than specific numbers. Based on results of recent bio-assay studies and on recommendations of the New York State Department of Environmental Conservation, Consolidated Edison has proposed discharge concentration limits for chemicals used at Indian Point Units 1, 2, and 3[1.4a] These limits are very conservative for reasons described in the report[1.4a] Therefore, achievement of the limits should cause no observable detrimental effects on the water body. The degree to which these company-imposed limits will be met are indicated in Table 1.4-1.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 acre-feet, 0 percent

All of the closed-cycle cooling subalternatives are essentially identical with respect to chemical discharges. Under this alternative plant design nearly all the same chemicals and quantities will be dis-

TABLE 1.4-1. PROPOSED AND EXPECTED CONCENTRATION LIMITS OF CHEMICALS AT CONFLUENCE WITH HUDSON RIVER

Chemical	Proposed Maximum Concentration Limits, ppm	Maximum Expected Concentration[a], ppm	Maximum Expected Concentration[c], ppm
Phosphate	1.54	0.001	0.002
Hydrazine	0.1	0.0002	0.0003
Cyclohexylamine	0.1	0.0005	0.0008
Lithium Hydroxide	0.01	0.0001	0.0002
Boric Acid	50	0.013	0.022
Potassium Chromate	0.05 (hexavalent chromium)	0.001	0.002
Residual Chlorine	0.5	0.5	0.5
Sodium Hydroxide (caustic soda)	10	0.006	0.010
Sulfuric Acid	10	(b)	(b)
Soda Ash	5	(b)	(b)
Detergent	1.0	0.002	0.003

(a) Based on discharges from Unit 3 and a dilution flow of about 2 million gpm.

(b) Not applicable for Indian Point Unit 3.

(c) Based on discharges from Unit 3 and a dilution flow of about 1.2 million gpm because of reduced flow during cold water river conditions.

charged as for Alternative A. However, during periods of maximum concentration of dissolved solids in the river (> 4700 ppm TDS as $CaCO_3$), sulfuric acid will be added to the Unit 3 make-up water to reduce the bicarbonate level to average concentration. The procedure substitutes sulfate for some of the bicarbonate in the river water that is used, resulting in a small change in TDS and a pH closer to neutral. Ultimate discharge to the river occurs via the approximately 14,400 gpm blowdown that is required for closed-cycle operation. The blowdown flow is chosen on the basis of maintaining a concentration factor of no greater than 2 for TDS. Table 1.4-2 summarizes the blowdown flow rates and the resulting salt discharges to the river for each of the closed-cycle cooling subalternatives.

The blowdown flow and the discharge of other plant chemicals from Unit 3 will be mixed with the once-through cooling water flow of Units 1 and 2 before delivery to the river. During the winter (summer), the once-through cooling water flow will be approximately 712,800 (1,188,000) gpm and, thus, the TDS content at confluence with the river will be higher than that in the river by less than 4.0 percent (2.4 percent). This is well within the normal variations experienced by the river[1.4b]. The concentration of the other plant chemicals at the confluence with the river will be a factor of 3.0 (1.8) greater than for Alternative A because of the reduced dilution flow [712,000 gpm (1.2 million gpm) versus 2.2 million gpm]. This increase is not considered significant since the anticipated discharge concentrations would still be below the proposed limits as given in Table 1.4-1.

TABLE 1.4-2. BLOWDOWN AND SALT DISCHARGES TO THE HUDSON RIVER FOR CLOSED-CYCLE COOLING SUBALTERNATIVES BB, BC, AND BD[a]

Cooling Subalternative	Method	Blowdown Flow Rates		Salt Discharged
		gpm	gal/yr	lb/yr
BB	Natural-Draft Towers	14,330	7.533×10^9	6.91×10^8
BC	Mechanical-Draft Towers	14,290	7.508×10^9	6.88×10^8
BD	Spray Pond	14,320	7.527×10^9	6.90×10^8

(a) Indian Point Unit 3 Environmental Report, Revised Section 17.

Alternative C. Plant License Request Design

Environmental Cost: 0 acre-feet, 0 percent

This design is identical to Alternative A.

1.4.2 Aquatic Biota

Alternative A. Plant As Is

Environmental Cost: 0 lb/year

Chemicals expected to be released into the discharge canal are to be of sufficiently low concentrations (after dilution by the discharge water) so as to protect aquatic biota from lethal or sub-lethal effects due to long-term or chronic exposure. The 1968 FWPCA Water Quality Criteria Report of the National Technical Advisory Committee to the Secretary of the Interior provides recommendations for the use of bioassays and application factors to denote safe concentrations of wastes in receiving streams[1.4c]. Bioassay work using young-of-the-year white perch and striped bass was conducted to determine the acute toxicity of chemicals used at Indian Point plants[1.4d]. Based on these results and on recommendations of the New York State Department of Environmental Conservation, discharge limits for chemicals used at Indian Point Station have been proposed. These limits, which are given in Table 1.4-1, either meet or are less than concentration limits that would be based on recommendations of the FWPCA Report. While the bioassays were limited to two species, the results are expected to encompass other species by a considerable

margin of safety. No mortalities would be expected even if all the chemicals were to be discharged simultaneously at the concentrations listed in Table 1.4-1. These safety margins are as follows:

(1) It is possible but extremely unlikely that the entire list of chemicals would be discharged simultaneously.

(2) Not all possible concentrations of each chemical were tested. It is entirely possible that somewhat higher concentrations of each chemical would have produced no increase in mortalities, so that the permissible concentrations would also be higher.

(3) The largest contributors to acute toxicity ratios are acids and bases (caustic soda and sulfuric acid). If these were discharged in combination, one would tend to neutralize the toxic effect of the other.

(4) Permissible concentrations were determined by 48-hour exposures, while the actual exposure time to the discharge concentrations would be momentary due to an almost instantaneous 50% reduction due to dilution as the discharge water empties from the canal into the river. This last set of factors on the side of safety would appear to be the most substantial of the list.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 lb/year

The discussion provided for Alternative B under Section 1.4.1 applies to this section as well.

Alternative C. Plant License Request Design

Environmental Cost: 0 lb/year

This alternative is identical to Alternative A.

1.4.3 Wildlife

All Alternatives

Environmental Cost: 0 acres

Chemical discharges are low for all alternatives and are diluted to sufficiently low concentrations (after dilution with the discharge water) that they are not expected to influence wildlife. Also, the discharge system tends to direct the bulk of the discharged water away from the shore habitats most often used by wildlife.

1.4.4 People

All Alternatives

Environmental Cost: 0 days, 0 acres

The concentration limits proposed for chemicals discharged into the Hudson River have been described in Section 1.4.1. All alternatives will achieve these limits and, therefore, should cause no observable detrimental effects on the recreational use of the river.

References to Section 1.4

(1.4a) Indian Point Unit 3 Environmental Report, Section 10.2

(1.4b) Indian Point Unit 3 Environmental Report, Section 4.3

(1.4c) "Water Quality Criteria", Report of the National Technical Advisory Committee to the Secretary of the Interior, FWPCA, April 1, 1968, Washington, D.C.

(1.4d) Testimony of Gerald J. Lauer, Ph.D., New York University, on "Effects of Chemical Discharges from Indian Point Units 1 and 2 on Biota and on River Chemistry", before the U.S. AEC in the matter of Consolidated Edison of New York, Inc. (Indian Point Unit No. 2), Docket No. 50-247, April 5, 1972.

1.5 Radionuclides Discharged to Water Body

1.5.1 Aquatic Organisms

Alternative A. Plant As Is

Environmental Cost:

Emission Source	Dose to Benthic Organisms Rem/year[a]	Dose to Fish Rem/year
Unit 3	2×10^{-1}	3×10^{-4}
Units 1, 2, 3	4×10^{-1}	6×10^{-4}

(a) After 40 years of plant operation.

The dose to benthos resulting from long-term accumulation of radionuclides on the river bottom near the station liquid discharge is selected as the conservative estimate of dose to this class of biota. Past studies of river biota have indicated no significant buildup of radioactivity in the organisms(*). The above dose rates are based upon (1) results of radiological monitoring studies, (2) known radionuclide releases from Unit 1, and (3) expected discharge rates from Units 1, 2, and 3 in the future. This conservative estimate of the benthic dose near the discharge point is about the same as the dose rate from natural radioactivity in the sediments(*). Dilution of the effluent downstream from the plant would reduce the dose to benthic organisms to an insignificant fraction of the natural background dose.

(*) See Appendix A for presentation of dose conversion factor tabulations which were developed as part of the IP-2 benefit-cost description. Since Unit 3 discharges are expected to be the same as for Unit 2, the dose conversion factors for Unit 2 are used.

The results for fish are for those residing in the immediate vicinity of the effluent from Indian Point Units 1, 2, and 3. The values are based on measured accumulations of the longer-lived radionuclides in fish taken from the river near Indian Point and on reconcentration factors available from the literature for other radionuclides(*). The dose rates also are based on a standard fish weight of 1 kg. The dose from ^{134}Cs and ^{137}Cs contributes about 90 percent to the total. At more distant points the radio-nuclide concentrations in the river will be lower and consequently, the environmental impact on migratory species such as striped bass may be considered negligible.

Alternative B. Modified Environmental Cost Design

Environmental Cost:

Emission Source	Dose to Benthic Organisms Rem/year	Dose to Fish Rem/year
Unit 3	3.4×10^{-1}	5.1×10^{-4}
Units 1,2,3	6.8×10^{-1}	1×10^{-3}

(*) See footnote on page 1.5-1.

The cost values for this alternative would be 1.70 times each of the numerical values given in the cost tabulation under Alternative A. This is because the discharge dilution flow for liquid wastes would be reduced from about 2.03 million gpm to about 1.19 million gpm. However, even with this increase the costs are negligible.

Alternative C. Plant License Request Design

Environmental Cost: Same as Alternative A

This alternative is identical to Alternative A.

1.5.2 People, External

Alternative A. Plant As Is

Environmental Cost:

Individual Radiation Dose

Emission Source	Rem/year/person		
	Swimming	Boating, Fishing, Skiing	Sunbathing
Unit 3	4.9×10^{-7}	4.9×10^{-7}	2.2×10^{-5}
Units 1,2,3	1.1×10^{-6}	1×10^{-6}	4.6×10^{-5}

Integrated Population Dose

Population	Man-rem/year		
	114,000	335,000	114,000
	Swimming	Boating, Fishing, Skiing	Sunbathing
Unit 3	5.6×10^{-2}	1.6×10^{-1}	2.5
Units 1,2,3	1.1×10^{-1}	3.4×10^{-1}	5.2

The individual radiation dose estimates are based on (1) measured river concentrations; (2) known liquid releases from Unit 1, and anticipated liquid releases from Units 1, 2, and 3; (3) 250 hours per year in-water activity for a swimmer; and (4) 500 hours per year above-water activity for boaters, skiers, or anglers(*).

The population dose estimates are each based on the conservative assumption that all persons living within 25 miles of the Indian Point site, who enjoy these activities, confine their activity to this section of the Hudson River. Usage by persons outside the 25-mile boundary are considered insignificant by this definition. No direct population use data for the river in the vicinity of the Indian Point site for the above activities could be located (probably becuase this reach of the river is slightly used for recreation purposes). Therefore, federal statistics on the recreational use of National Forest lands and waters were employed to estimate the percentage of the general population which engage in each activity(1.5b). These estimates are undoubtedly high and, therefore, will produce inflated estimates of environmental costs. The values, weighted according to use rate, are swimming and sunbathing, 4.0 percent; boating, skiing, and fishing, 11.8 percent. These percentages were applied to the projected 1980 population for the area(1.5c) to obtain the approximate number of persons that would be engaged in each activity when the plant is scheduled to go into operation (second half of 1974). The applicable population figures are shown on the environmental cost unit table.

(*) See footnote on page 1.5-1.

In transferring this cost information to the Cost Description Forms, the maximum cost figure due to Unit 3 alone was used (the doses due to sunbathing). This cost figure and all the others are quite small when compared against the radiation exposure values that the same individual or population group receives annually from natural background. The appropriate whole body doses, due to natural background for the region around Indian Point, are given in Table 1.5-1. Comparison shows that the estimated sunbathing doses resulting from the Unit 3 effluent are only 0.02 percent of the natural background doses.

TABLE 1.5-1. REFERENCE DOSE DATA[a]

	Individual (Rem/yr)	Population	
		114,000	335,000
		Man/rem-yr	
Natural background	0.11	12,500	36,800

(a) Indian Point Unit 2 Environmental Report, Supplement No. 1, September 1971, p. 2.3.7-18.

Alternative B. Modified Environmental Cost Design

Environmental Cost:

Individual Radiation Dose

Emission Source	Rem/year/person Swimming	Boating, Fishing, Skiing	Sunbathing
Unit 3	8.3×10^{-7}	8.3×10^{-7}	3.7×10^{-5}
Units 1,2,3	1.7×10^{-6}	1.7×10^{-6}	7.8×10^{-5}

Integrated Population Dose

	Man-rem/year		
Population -	114,000 Swimming	335,000 Boating, Fishing, Skiing	114,000 Sunbathing
Unit 3	9.5×10^{-2}	2.7×10^{-1}	4.3
Units 1,2,3	1.9×10^{-1}	5.8×10^{-1}	8.8

The cost values for this alternative would be 1.70 times each of the numerical values given in the cost tabulation under Alternative A. This is because the discharge dilution flow for liquid wastes would be reduced from about 2.03 million gpm to about 1.19 million gpm. The maximum value for Unit 3 alone is the one transferred to the Cost Description Forms.

Alternative C. Plant License Request Design

Environmental Cost: Same as Alternative A

This alternative is identical to Alternative A.

1.5.3 People, Ingestion

Alternative A. Plant As Is

Environmental Cost:

Drinking River Water	Individual Radiation Dose[a] Rem/year/person	
	Whole Body[b]	Thyroid[c]
Unit 3	7.7×10^{-7}	2.8×10^{-6}
Units 1, 2, 3	1.6×10^{-6}	5.6×10^{-6}

(1.11×10^{6} persons)	Population (1.11×10^{6} persons) Man-rem/year
	Whole Body
Unit 3	0.77
Units 1, 2, 3	11.6

Eating Fish From River	Individual Radiation Dose[a] Rem/year/person	
	Whole Body	Thyroid[c]
Unit 3	1.2×10^{-5}	4.8×10^{-5}
Units 1, 2, 3	2.4×10^{-5}	9.6×10^{-5}

(7.90×10^{5} persons)	Population (7.90×10^{5} persons) Man-rem/year
	Whole Body
Unit 3	95
Units 1, 2, 3	190

(a) Doses to G.I. tract and to bone small compared to the estimated thyroid dose.

(b) Dose to whole body due almost entirely to tritium.

(c) Dose for thyroid of adult.

The dose from drinking water at the Chelsea pumping station (21.3 miles upstream from Indian Point) is calculated based on (1) the theoretical model described in Appendix A to the Indian Point Unit No. 3 Supplemental Report (Eq. 21 and 24, pages 13 and 14), (2) an adult intake rate for drinking water of 2.2 liters per day (rate for a

child of 1 liter per day),and (3) the known and expected radionuclide composition of liquid discharges from Units 1, 2, and 3(*). The man-rem/year values are based on an exposed population figure of 1.11 million persons. This number was obtained by assuming that the entire pumping capacity of the Chelsea station(1.5d), 100 million gallons per day, would be used for nonindustrial public purposes at the national average usage rate of 90 gallons per day per person(1.5e)

The individual radiation doses from eating fish taken from the river are based on (1) a human consumption rate of 30 grams of fish per day taken in the vicinity of the station liquid outfall and (2) radionuclide concentrations in fish estimated from results of pertinent monitoring studies(*) or derived from calculated river concentrations and published concentration factors for chemical elements in fish(1.5f). The man-rem/year data are based on an exposed population figure of 790,000 persons. This estimate was obtained by using results of a recent study which indicated that in 1965 some 200,000 sport fishermen from the New York-Connecticut-New Jersey area caught about 19 million pounds of striped bass. The main source of the catch was the Hudson River(1.5g). Using this figure and an individual consumption rate of 24 lbs per year (30 g per day), 790,000 persons would be exposed to the radioactivity in those fish.

In transferring this cost information to the Cost Description Forms, the maximum cost figure due to Unit 3 alone was used (the whole body dose from eating fish). This cost figure is small compared to radiation exposure

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(*) See footnote on page 1.5-1.

values that the same individual or population group receives annually from natural background. The appropriate whole body doses, due to natural background for the region around Indian Point, are given in Table 1.5-2. Comparison shows that the estimated whole body dose from drinking river water is about 0.001 percent of the natural background dose.

TABLE 1.5-2. REFERENCE DOSE DATA

	Whole Body Dose	
		Population (7.90×10^5)
	Individual (Rem/yr)	Man-rem/yr
Natural Background	0.11	86,900

Alternative B. Modified Environmental Cost Design

Environmental Cost:

Drinking River Water	Individual Dose[a] Rem/year/person	
	Whole Body[b]	Thyroid[c]
Unit 3	7.7×10^{-7}	2.8×10^{-6}
Units 1, 2, 3	1.6×10^{-6}	5.6×10^{-6}

	Population (1.11×10^6 persons) Man-rem/year
	Whole Body
Unit 3	0.77
Units 1, 2, 3	1.6

(a) Doses to G.I. tract and to bone small compared to the estimated thyroid dose.
(b) Dose to whole body due almost entirely to tritium.
(c) Dose for adult thyroid.

Eating Fish From River	Individual Radiation Dose[a] Rem/year/person	
	Whole Body	Thyroid[c]
Unit 3	2.0×10^{-5}	8.2×10^{-5}
Units 1, 2, 3	4.1×10^{-5}	1.6×10^{-4}

	Population (7.90×10^5 persons) Man-rem/year
	Whole Body
Unit 3	16.2
Units 1, 2, 3	32.3

(a) Doses to G.I. tract and to bone small compared to the estimated thyroid dose.
(b) Dose to whole body due almost entirely to tritium.
(c) Dose for thyroid of adult.

The cost values for this alternative relative to Alternative A would be the same for the case of drinking river water but would be 1.70 times greater for the case of eating fish taken from the river. The difference for the two cases results from the different procedures used in making the dose calculations. River mixing and dilution of the radioactive discharge from the Indian Point station were considered in the drinking water calculations. The results depend only on activity discharged and not on the concentration at the discharge point. Since the same activity discharges will occur for both alternatives, no change in cost values will take place. The fish consumption dose calculations, however, assume the entire catch is taken from the immediate vicinity of station outfall. Here, the reduced station dilution flow, caused by closed cycle operation, would result in instantaneous activity concentrations that would be a factor of 1.70 higher for Alternative B relative to Alternative A. The dose from fish consumption appears in the Cost Description Forms since the exposure via this pathway represents the maximum cost value.

Alternative C. Plant License Request Design

Environmental Cost: Same as Alternative A

This alternative is identical to Alternative A.

References to Section 1.5

(1.5a) Radiological Health and Data Reports, Vol. 12, No. 9, September, 1971, Environmental Protection Agency, Radiation Office.

(1.5b) U.S. Bureau of the Census, "Statistical Abstract of the United States--1971", 92nd Annual Edition, Washington, D.C., 1971, Table No. 306, p. 194.

(1.5c) Indian Point Unit 3 Environmental Report, Supplement 2, Appendix F (July, 1972).

(1.5d) Indian Point Unit 3 Environmental Report, Section 8.2.

(1.5e) "Encyclopedia Britannica", Vol. 23, p. 431 (1964).

(1.5f) Chapman, W. H., Fisher, H. L., and Pratt, M. W., "Concentration Factors of Chemical Elements in Edible Aquatic Organisms", UCRL-50564 (1968).

(1.5g) Clark, J. R., and Smith, S. E., "Migratory Fish Studies of the Hudson Estuary", Second Symposium on Hudson River Ecology (1969), p. 293.

1.6 Consumptive Use

1.6.1 People

All Alternatives

Environmental Cost: 0 gal/year

The Hudson River near and below Indian Point is not used for drinking water purposes. The nearest point at which water is withdrawn from the river for drinking purposes is the Castle Point Veterans Hospital which is about 20 miles upstream from the plant site[1.6a]. The Chelsea Pumping Station which supplies New York City is located almost 22 miles upstream. Thus, none of the above alternatives will have an effect on drinking water supplies. In addition, even though the closed-cycle cooling subalternatives will result in evaporative water losses, these also will have no effect on drinking water supplies.

1.6.2 Property

All Alternatives

Environmental Cost: 0 acre-ft/year

The Hudson River near and below Indian Point is not used for irrigation purposes[1.6a]. There is a little agricultural and grazing

within a 15-mile radius of the site[1.6b], but this activity does not require irrigation. Also, the salinity of the river water is usually too high for irrigation purposes. Therefore, any water consumption by the above cooling subalternatives will have no effect on local agriculture.

References to Section 1.6

(1.6a) Indian Point Unit 3 Environmental Report, Section 8.1.

(1.6b) Indian Point Unit 3 Environmental Report, Section 4.6.

1.7 Other Impacts

No other impacts have been identified.

1.8 Combined or Interactive Effects

There is no evidence that measures of combined effects of a number of impacts are different from measures of the separate impacts.

2. GROUNDWATER

2.1 Raising/Lowering of Groundwater Levels

2.1.1 People

All Alternatives

Environmental Cost: 0 gal/year

For each of these alternatives the plant condenser cooling water and service water supply is taken from the Hudson River. The plant does not use well water[2.1a]. Therefore, plant operations under all of these alternatives will not affect local groundwater levels.

2.1.2 Plants

Alternative A. Plant As Is

Environmental Cost: 0 acres

No lowering of groundwater levels in the immediate vicinity of the Indian Point site due to plant operations should occur, based on the analysis presented immediately above under Section 2.1.1. The plant under this alternative discharges no water over the general landscape, so the raising of groundwater levels is also precluded. Thus, plant operations will have no effect on the water supply of deep-rooted vegetation in the area.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 acres

Based on the analysis presented in Section 2.1.1, no lowering of groundwater levels in the immediate vicinity of the Indian Point site should occur as a result of plant operations under this or any of the subalternative cooling methods that have been considered. Each of the auxiliary cooling alternatives results in the spray drift of water over the general landscape which could conceivably raise subsurface water levels. However, hydrological surveys of the region have shown that surface waters will drain to the river. Thus, drift from the plant should not affect groundwater levels nor deep-rooted vegetation which utilizes this water.

Alternative C. Plant License Request Design

Environmental Cost: 0 acres

This alternative is identical to Alternative A.

References to Section 2.1

(2.1a) Indian Point Unit 3 Environmental Report, Section 8.

2.2 Chemical Contamination of Groundwater

2.2.1 People

All Alternatives

Environmental Cost: 0 gal/year

No environmental cost will occur from any of the alternatives for this category because the few wells that may provide drinking water to nearby residents are shallow and at ground elevations that are considerably higher than the plant site. Thus, groundwater at the site flows to the Hudson River[2.2a]. Chemical discharges from the plant, under each of the alternatives, are made at the beginning of the station cooling water discharge canal and, consequently, travel with dilution directly to the river.

2.2.2 Plants

All Alternatives

Environmental Cost: 0 acres

Chemical discharges from the plant, for each of the cooling subalternatives, are made at the beginning of the station cooling water discharge canal and, consequently, travel with dilution directly to the Hudson River[2.1a]. Under Alternative B residual chlorine, following condenser chlorination treatment at levels of 0.1 to 0.5 ppm might be realized during passage of the cooling water through each of the subalternative systems. However, chemical reduction to chloride should readily occur and this level of chloride would be negligible.

References to Section 2.2

(2.2a) Indian Point Unit 3 Environmental Report, Section 4.1.

2.3 Radionuclide Contamination of Groundwater

2.3.1 People

All Alternatives

Environmental Cost: 0 rem/yr, 0 man-rem/yr

The absence of any environmental effect on groundwater supplies is based on the known hydrology of the Indian Point site area[2.3a]. The ground surface elevations of the adjacent land are considerably higher than the plant site. Thus, the direction of groundwater flow is towards the river, and this precludes the possibility of contamination of these supplies through groundwater flow[2.1a].

2.3.2 Plants and Animals

All Alternatives

Environmental Cost: 0 rad/yr

The potential radiation dose to terrestrial plants and animals resulting from radioactivity releases from Indian Point Units 1, 2, and 3 are considered in Section 3.3.3. Therefore, contributions from this groundwater source are not applicable and have been assigned a zero value.

References to Section 2.3

(2.3a) Indian Point Unit 3 Environmental Report, Section 4.2.

2.4 Other Impacts on Groundwater

No other impacts on groundwater have been identified.

3. AIR

3.1 Fogging and Icing

3.1.1 Ground Transportation

Alternative A. Plant As Is

Environmental Cost: 0 hours per year

Since once-through cooling does not discharge any water into the air, there will be no increase in the annual occurrence of fog or ice on roads and, therefore, no increase in driving hazards from Alternative A.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 hours per year

In order to assess this impact and the impacts listed under Categories 3.1.2, 3.1.3, and 3.1.4, it is necessary to estimate the increase in the annual number of hours of fog due to the cooling sub-alternatives at locations surrounding the Indian Point site. Table 3.1-1 gives these values for the sector showing the greatest increase and the average for the entire area between radii of 0-1, 1-2, 2-3, 3-4, 4-5, and 5-10 miles of the site. These values were calculated using (1) the annual frequency of saturation deficits over Poughkeepsie, New York and (2) the radioactivity dispersion factors used to estimate radiation doses (see Section 3.3) and salt deposition (see Section 4.3). The confidence in the radioactivity factors for the natural-draft tower is not good because of difficulties in scaling the radioactivity factors to the effective plume height of the tower. These difficulties are discussed in Section 4.3. However, because the effective plume height

TABLE 3.1-1. INCREASE IN FOG AT RIVER ELEVATION

Alternative	Water Discharged into Air, gpm [a]	Increase in Fog at River Elevation, hours/year											
		0-1 miles		1-2 miles		2-3 miles		3-4 miles		4-5 miles		5-10 miles	
		Maximum Sector	Average of Entire Circle	Maximum Sector	Average of Entire Circle	Maximum Sector	Average of Entire Circle	Maximum Sector	Average of Entire Circle	Maximum Sector	Average of Entire Circle	Maximum Sector	Average of Entire Circle
AA	0	0	0	0	0	0	0	0	0	0	0	0	0
BB	14,380	0	0	0	0	0	0	0	0	0	0	0	0
BC	14,443	175	88	88	5	0	0	0	0	0	0	0	0
BD	14,390	6044	4643	3679	2102	1664	876	1402	613	1051	438	350	175

(a) Drift assumed to be 0.0025 percent of cooling water flow for natural-draft towers (Subalternative BB), 0.008 percent for mechanical-draft towers (Subalternative BC), and 0.004 percent for spray ponds (Subalternative BD).

is so large (in excess of 1000 feet), the estimates for fog at river level due to the natural-draft tower are essentially zero so that the inaccuracies in the factors do not effect the conclusion that there is no river-level fog from natural-draft tower.

The theoretical equations used to calculate the increase in annual hours of fog are similar to the equations for estimating dispersion of radioactivity as discussed in Section 3.3. The excess humidity (over ambient) at a given location was calculated as the product of the rate at which water is discharged into the air and the radioactivity factor corresponding to the location's sector and distance from the site. The cumulative frequency for which the saturation deficit is less than or equal to this excess humidity was then determined from the Poughkeepsie data. The water in the plume would tend to evaporate if the saturation deficit was greater than the excess humidity. Therefore, the cumulative frequency for which the deficit is at or below the excess humidity is a measure of the cumulative frequency of fog (condensed water). Part of this fog would coincide with periods of natural fog. The occurrence of fog was assumed to be the frequency of zero deficit (when the air is saturated with water vapor). This frequency of zero deficit was, therefore, subtracted from the cumulative frequency corresponding to the excess humidity in order to arrive at the frequency of increased fog due to the cooling alternatives. The product of this latter frequency and the number of hours in a year (8,760) is the estimate of the increased hours of fog due to the cooling alternative.

As discussed in Section 4.3, the confidence in the calculations is not good for the natural-draft tower, but the fog estimates are essentially zero so that possible errors in the calculations are not significant. The confidence in the calculations for spray ponds is also not good for distances greater

than one mile because the calculations do not account for rainout of the condensed water. The calculated values of excess humidity would indicate that large amounts of rainout could occur within one mile during most of the time. This rainout would remove excess water from the plume so that locations beyond one mile would have a much lower frequency of fog than is indicated in Table 3.1-1. However, the values in the table can be considered as upper-limit estimates of fog beyond one mile, while the lower-limit estimates would be essentially zero fog beyond one mile.

In assessing the environmental cost, it was noted that a major highway runs within one mile of the site, but not necessarily in the direction of the maximum sector. Therefore, the environmental cost was taken as the average increase in the annual hours of fog within one mile of the site, and this was also taken as the hours of increased driving hazard. For reasons discussed in the introductory section on alternatives, the natural-draft cooling tower operating in a closed-cycle, Subalternative BB, was chosen as Alternative B. From Table 3.1-1 the increase in the annual occurrence of fog within one mile of the site for this alternative is 0 hours. The increase is 88 hours for Subalternative BC (mechanical-draft tower, closed-cycle) and 4,643 hours (53 percent of the time) for Subalternative BD (spray pond operated at closed-cycle).

It should be noted that fog at the river level may not be the maximum. In fact, the maximum increase in fog would occur at about the plume height. Since the terrain is hilly in the area and the effective plume height for the mechanical-draft towers is only about 400 feet, it is possible that some locations could receive increases in the occurrence of fog that are greater than the values shown in Table 3.1-1. For

elevations approaching 400 feet above the river, the increase in annual hours of fog from the mechanical draft towers could approach the values for spray ponds. However, the increases in fog at the river level were felt to be the best representation of the environmental cost of the alternatives.

Alternative C. Plant License Request Design

Environmental Cost: 0 hours per year

This alternative is identical to Alternative A.

3.1.2 Air Transportation

Alternative A. Plant As Is

Environmental Cost: 0 hours per year

Since once-through cooling does not discharge any water into the air, there will be no increase in the annual occurrence of fog at airports and, thus, no closing of airports due to Alternative A.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 hours per year

The estimates of annual increase in fog for the surrounding locations were given in Table 3.1-1 and the methods used to arrive at these estimates were given in Section 3.1.1 In assessing this environmental cost, it was noted that there is a sea plane base at Verplanck, approximately 1.57 miles south of the site. The sector having the maximum frequency of fog is also toward the south. Therefore, the environmental

cost was taken as the maximum increase in the annual hours of fog between 1 and 2 miles of the site, and this was assumed to equal the hours during which the airport would close. For reasons discussed in the introductory section on alternatives, the natural-draft tower operating closed-cycle, Subalternative BB, was chosen as Alternative B. From Table 3.1-1, the increase in the annual occurrence of fog within 1 to 2 miles of the site for this Subalternative is 0 hours. The increase is 88 hours for Subalternative BC (mechanical-draft tower, closed-cycle) and 3,679 hours for Subalternative BD (spray pond, closed-cycle). As mentioned before in Section 3.1.1, the spray pond values are upper-limit estimates beyond one mile. Also, as previously mentioned in Section 3.1.1 the effect of elevation may be significant in that there may be an increase in occurrence of clouds at the 400-foot level for mechanical-draft towers and at the 1000-foot level for natural-draft tower. These increases could approach the values for spray ponds.

Alternative C. Plant License Request Design

Environmental Cost: 0 hours per year

This alternative is identical to Alternative A.

3.1.3 Water Transportation

Alternative A. Plant As Is

Environmental Cost: 0 hours per year

Once-through cooling does not discharge any water into the air but will result in a small surface area having a significant temperature

rise as seen in Section 1.3.1. Such a small area could increase the occurrence of radiation fog over the river, but this effect is not expected to be severe enough to affect water transportation.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 hours per year

The estimates of the increase in the occurrence of fog for the surrounding areas were given in Table 3.1-1 and the methods used to arrive at these estimates were given in Section 3.1.1 In assessing this environmental cost, it is significant that the site is located on the Hudson River, which is navigable. Also, the sector having the maximum frequency of fog tends to be in a southerly direction over the river. Therefore, the environmental cost was taken as the maximum increase in the annual hours of fog within 1 mile of the site, and this value was assumed to equal the hours during which ships on the river must reduce speed. For reasons discussed in the introductory section on alternatives, the natural-draft tower operating closed-cycle was chosen as Alternative B. From Table 3.1-1 , the increase in the maximum annual occurrence of fog within one mile of the site is zero hours. The increase is 175 hours for Subalternative BC (mechanical-draft tower, closed-cycle) and 6,044 hours for Subalternative BD (spray pond, closed-cycle).

Alternative C. Plant License Request Design

Environmental Cost: 0 hours per year

This alternative is identical to Alternative A.

3.1.4 Plants

Alternative A. Plant As Is

Environmental Cost: 0 acres

Since once-through cooling does not discharge any water into the air, there will be no increase in the annual occurrence of fogging and icing conditions, and consequently, no damage to plant life due to Alternative A.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 acres

There is very little experimental evidence upon which to base an accurate assessment of the potential effects on plant life from the fogging and icing conditions produced by the various cooling alternatives. Some general statements can be made concerning the nature of some of these effects. For instance, evaporation and drift losses from the cooling towers and/or spray ponds could result in an increase in the relative humidity of the area. Since the vapor pressure gradient between the atmosphere and the moist plant surfaces would be lowered, a reduction in the rate of evaporation and transpiration could possibly occur. Also, the increased moist air conditions could favor certain fungi which might become serious pests on higher plants in the area.

The estimated environmental cost for each cooling subalternative is below and expresses the number of acres exposed to increased fog frequencies and hence some possible detrimental effects on plant life. Concerning icing phenomena, ice formation on vegetation could occur during those periods when ambient temperatures are below freezing. Temperature

statistics[3.1a] for New York City indicate that the monthly mean low temperature is below freezing for only three months of the year--December, January, and February. However, the monthly mean high temperature for these same months is above freezing. Therefore, as an approximation, it may be assumed that the potential for icing occurs only about 1/8 or 12.5 percent of the time on an annual basis.

Since there are no increases in ground-level fog frequencies predicted for Subalternative BB (natural-draft cooling tower), there would be no environmental costs to surrounding vegetation. Very little, if any, damage to plant life would be expected to result from the increases in the frequency of ground fog predicted for Subalternative BC (mechanical-draft cooling towers).

The spray pond subalternative would produce the greatest potential for damage to surrounding plant life resulting from fogging and icing. From the fog frequency data in Table 3.1-1 , it can be seen that the area encompassed by the 0-1, 1-2, and 2-3 mile radii would be subjected to significant increases in fogging conditions.

Within this 3-mile radius of the plant site are some 11,762 acres of land with approximately the following utilization:

Residential - 7,238 acres
Recreational - 3,619 acres
Industrial - 905 acres.

The plant life on these 11,762 acres could suffer potential detrimental effects from the fogging conditions attributed to this cooling alternative and the environmental cost would be moderate.

Alternative C. Plant License Request Design

Environmental Cost: 0 acres

This alternative is identical to Alternative A.

References to Section 3.1

(3.1a) U.S. Bureau of Census, "Statistical Abstract of the United States, 1971", 92nd Annual Edition, Washington, D.C., Table No. 286, p. 176.

3.2 Chemical Discharges to Ambient Air

3.2.1 Air Quality, Chemical

All Alternatives

Environmental Cost: 0 percent: 375,000 lb/year SO_2; 15,000 lb/yr particulates; 342,000 lbs/yr NO_x

Indian Point Unit 3, like other nuclear power plants, will release no combustion products to the atmosphere as a result of reactor operation. It will, however, have two "package boilers" fueled by #6 fuel oil (0.37 percent sulfur) to produce auxiliary service steam for startup and service heating. The exhaust from these boilers will be discharged through the Unit No. 1 superheater stack and will emit 15,000 lb particulates, 375,000 lb SO_2, and 342,000 lb NO_x annually[3.2a].

The annual emission rates were used to calculate the ground-level concentrations of these pollutants at a distance of 1 km downwind from the stack under Class A stability conditions and with a wind speed of 2 m/sec. This distance (1 km) is the approximate position of the maximum, ground-level concentration under these conditions. The stack height used in these calculations was the actual stack height (88.6 m) instead of the effective height which is considerably greater. As a result, these pollutant concentrations are overestimates of the maximum ground-level concentrations expected with these meteorological conditions. The calculated concentration values are 3.3×10^{-3} ppm for SO_2, 4.2×10^{-3} ppm for NO_x, and 0.35 micrograms/m^3 for particulate.

The national primary ambient air quality standards (annual arithmetic mean) to be achieved by 1975 for the three pollutants are 3×10^{-2} ppm for SO_2, 5×10^{-2} ppm for NO_x, and 75 micrograms/m^3 for

particulates. These calculated values are, however, instantaneous or 3-minute concentrations. Annual average values are usually a small fraction of the instantaneous values. Since the calculated instantaneous concentrations are already much smaller than the national ambient standards, the annual averages would be insignificant.

3.2.2 Air Quality, Odor

All Alternatives

Environmental Cost: None

Although a few chemicals of an organic nature are anticipated for use in the plant, the amounts will be so small and their concentrations in the atmosphere and in discharge waters will be so low that no perceptible odors will be experienced at offsite locations.

References to Section 3.2

(3.2a) Indian Point Unit 3 Environmental Report, Section 10.5.

3.3 Radionuclides Discharged to Ambient Air

3.3.1 People, External

All Alternatives

Environmental Cost:

Individual Radiation Dose[a]

Rem/year/person*

Distance from IP-3	Whole Body
350 meters	3.58×10^{-3}
500 meters	3.01×10^{-3}
1000 meters	6.7×10^{-4}
2000 meters	2.1×10^{-4}
5000 meters	4.5×10^{-5}

*In critical wind sector which is S-SW of the site.

(a) Individual and population radiation dose values for Indian Point Units 2 and 3 combined would be less than twice the values for Unit 3 alone. The contribution due to gaseous discharges from Unit 1 are negligible for reasons discussed in the text.

Population Radiation Dose[a]

Distance from IP-3	Cumulative Population	Cumulative Man-rem/year Whole Body
1 mile	745	0.08
2	9,255	0.31
5	52,683	0.69
10	218,398	1.3
15	450,207	1.4

(a) Individual and population radiation dose values for Indian Point Units 2 and 3 combined would be less than twice the values for Unit 3 alone. The contributions due to gaseous discharges from Unit 1 are negligible for reasons discussed in the text.

The gaseous wastes discharged from Unit 3 are expected to be: Xe-133, 4230 Ci/year; Kr-85, 1150 Ci/year; and I-131, 0.155 Ci/year[3.3a]. The individual radiation dose estimates are based on these release rates occurring at ground level. Dispersion of the source was calculated as a function of distance in the limiting land sector using annual average measured meteorological data. The gamma dose values were generated using the semi-infinite cloud method. Corresponding dose calculation results are not given for Unit 1 because the activity discharges are much lower than for Units 2 and 3 and the release is made from the superheater stack. The elevated release alone results in atmospheric dilution factors which range from ten to fifty above that for the ground level release used for Units 2 and 3[3.3c], depending on distance from the plant site.

The population data used in the man-rem/year calculations are based on 1970 census data. Using the same gaseous ground level release data, and annual average X/Q[3.3c] dispersion data for all sectors around the site, the annual "steady state" distribution of airborne radioactivity in a series of concentric rings out to a distance of 15 miles was calculated. The total annual whole body dose was computed for each angular-radial sector and then multiplied by the population value to obtain the annual man-rem quantity. The man-rem/year values were then summed, first around the circle, and then radially to develop the cumulative data given in the above tabulation.

In transferring this cost information to the Cost Description Forms, the maximum cost values for each unit of measure were used. These cost figures are small compared to radiation exposure values that the same individual or population group receives annually from natural background. The appropriate whole body doses due to natural background for the region around Indian Point are given in Table 3.3-1. Comparison shows that the estimated whole body dose at the plant site boundary due to radioactive gaseous discharges from the plant are about 4 percent of the natural background dose. For points further removed from the site boundary, the percent of natural background is much less.

TABLE 3.3-1. REFERENCE DOSE DATA

Distance from IP- 3	Natural Background Whole Body Dose Rem/year	Cumulative Population Dose Man-rem/year
1 mile	0.11	82
2	0.11	1,019
5	0.11	5,807
10	0.11	24,010
15	0.11	49,379

3.3.2 People, Ingestion

All Alternatives

Environmental Cost:

	Thyroid Dose rem/year/person	
	Adult	Child
Unit 3	1.5×10^{-4}	1.5×10^{-3}
Units 1, 2, 3	3×10^{-4}	3×10^{-3}

	Thyroid Dose man-rem/year	
	Adult	Child
Unit 3	5.7	57
Units 1, 2, 3	11.4	114
Population	38,000	38,000

Based upon the anticipated composition of gaseous emissions from IP-3[3c], I-131 represents the most significant ingestion hazard. Due to the concentration of iodine in the pasture-cow-milk-man food chain, human consumption of milk is used to assess the maximum ingestion radiation dose that could occur[*]. The resulting thyroid dose values assume: (1) a daily milk consumption rate of 1 liter taken from the nearest (approximately 7 miles) dairy farm in the limiting wind sector, (2) a factor of 700 in converting from 10CFR20 maximum permissible air concentration to thyroid accumulation, and (3) a grazing period for the cows for the entire year[3.3b].

(*) On a population exposure basis it can be shown that direct inhalation of airborne I-131 produces a thyroid dose of 1.4 mRem/year which is comparable to the dose derived from milk consumption by a child.

Within 20 miles of the Indian Point site there were (according to a 1966 survey)[3.3d] a total of 122 dairy farms producing 80,250 quarts of milk daily. Assuming a human consumption rate of 1 liter of milk per day, this volume of milk would supply the daily diet requirements of 76,000 persons; approximately equally divided between adults and children. Although more recent data indicate a considerable decline in the number of dairy farms in the region [3.3e], specific numbers and capacity are not available. Therefore, the above figures will be used. It is further conservatively assumed that all of this milk contains I-131 at the same concentration as predicted for milk taken from the nearest dairy in the limiting wind sector in computing the annual man-rem (thyroid) values. The intergrated population dose due to any other radionuclides that might be released to the atmosphere should be less than these values.

The tabulated cost figures are small compared to thyroid exposures that the same individuals or population groups receive annually from natural background sources. The average background in the vicinity of the plant is about 110 millirem per year[3.3b] (0.11 rem/year). On this basis the conservative dose estimates due to plant operation are less than 0.1 percent and 1.0 percent of natural background doses for adults and small children respectively.

b.

3.3.3 Plants and Animals

All Alternatives

Environmental Cost:

	Dose to Animal Thyroid rem/year
Unit 3	0.36
Units 1, 2, 3	0.72

This quantity represents the maximum internal radiation exposure expected for terrestrial plants and animals because (1) noble gas radionuclides are not retained by biota, (2) iodine-131 is the only other species which is discharged in significant quantities to the atmosphere and (3) the accumulation factor for iodine in the thyroid of a large grazing animal combines an appreciable forage area (50 m^2) with an organ specificity (0.3). This dose is considered especially conservative since it is not expected that a large animal would graze over such a large area so close to the plant's site boundary. The deposition of I-131 on the pasture was calculated from annual average X/Q data for the limiting wind sector, at a point corresponding to the plant site boundary, and using a deposition velocity of 1 cm/sec[3.3b].

References to Section 3.3

(3.3a) Indian Point Unit No. 3 Environmental Report, Section 14.2, Supplement 2.

(3.3b) "An Analysis of Radiation Doses to Man and Biota from Projected Radiation Releases from Indian Point Units 1 and 2", Report of McDonald E. Wrenn, Ph.D. and Norman Cohen, Ph.D., to Consolidated Edison Company, March, 1972.

(3.3c) Information supplied by Consolidated Edison Company

(3.3d) "Consolidated Edison Indian Point Reactor Environmental and Post Operational Survey: July 1966". Report of New York State Department of Health, Division of Environmental Health Services, July 1966.

(3.3e) Bratton, C. A., "Changes in New York State Agriculture, 1969 Census Data", Department of Agricultural Economics, New York State College of Agriculture and Life Sciences, Cornell University, November, 1971.

(3.3f) Eisenbud, M., Environmental Radioactivity, McGraw-Hill, New York, 1963, p. 165.

3.4 Other Impacts on Air

No other impacts on the air environment have been identified.

4. LAND

4.1 Pre-emption of Land

4.1.1 Land, Amount

Alternative A. Plant As Is

Environmental Cost: 0 acres

This alternative requires no additional land since it is located on the present Indian Point site.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 acres

This alternative (Subalternative BB) requires space for construction of a natural-draft cooling tower, but adequate land exists on-site to accommodate this structure. For Subalternative BC, sufficient on-site land is available for the mechanical-draft cooling towers. For Subalternative BD, the required spray pond would also be located on land owned by Consolidated Edison.

Alternative C. Plant License Request Design

Environmental Cost: 0 acres

This alternative is identical to Alternative A.

4.2 Plant Construction and Operation

4.2.1 People (Amenities)

Alternative A. Plant As Is

Environmental Cost: 0 residents, schools, or hospital beds within area having noise above present levels.

In general, nuclear power plants are relatively quiet facilities as compared with other industrial plants of the same approximate physical size. The reactor, turbine, and large pumps are normally enclosed in buildings, and although in some cases the noise inside the buildings may be high (for example, in a large pump room), the buildings substantially attenuate the noise transmitted to the outside. In addition, the plant site is heavily wooded and varies in elevation, which are desirable characteristics from a noise attenuation standpoint. However, any noisy equipment that may be located outside the buildings may result in objectionable sound levels to the surrounding areas. The degree to which this noise is objectionable depends on the "ambient" noise level in the area, and the use of the area--for example, residential or industrial.

The ambient noise levels now existing in the area were measured at locations which were chosen to document noise levels at the Consolidated Edison property Line and also at locations in the surrounding area where noise might affect the residents or where other noise sources exist. Table 4.2 is a brief description of each location.

The general impression gained during the noise measurement field trip was that traffic noises were the predominant noises in the area. This included not only highway traffic, but also rail and general aviation traffic (small- and medium-size planes). At several measurement locations,

TABLE 4.2. DESCRIPTION OF LOCATIONS WHERE MEASUREMENTS OF NOISE LEVELS WERE MADE

Location 1:	100 ft NE of the intersection of Broadway and Bleakley (residence near).
Location 2:	Approximately 2200 ft SE of Indian Point reactor facility on the east side of Broadway (residence near).
Location 3:	On peak of hill in cemetery, about 3300 ft south of Indian Point reactor facility, 250 ft east of Broadway.
Location 4:	About 250 ft south of the Consolidated Edison substation and 90 ft north of gas turbine power plant.
Location 5:	On the boat dock at the Indian Point facility.
Location 6:	On hill about 3900 ft south of Indian Point reactor facility and 5600 ft east of fossil fuel power plant across the river.
Location 7:	On west bank of Hudson River about 4800 ft NNW from Indian Point reactor facility (residence near).
Location 8:	About 700 ft to 750 ft west of fossil fuel power plant on west side of Hudson River (residence near).

attempts to obtain measurements of the ambient levels with no obvious traffic noise required waiting several minutes to obtain a time when local or nonlocal traffic noise was not present. Other predominant noise sources in the Indian Point area were (1) the fossil fuel power plant installation located on the west side of the Hudson River across from Verplanck and (2) the small Consolidated Edison gas turbine generator station located on the east side of Broadway across from the Indian Point facility fence. This generator station may operate continuously during peak demand periods of several days.

As directed by the AEC, the criteria with which present and predicted future noise levels were compared were those now under consideration by HUD[4.2a]. If adopted, these will apply only to areas where residences might be built and will be used by HUD as one criterion to determine whether the area is appropriate for residences where HUD funding is requested. While no such areas appear to be involved in this case--that is, the area in the vicinity of the Consolidated Edison property does not appear to be suitable for any substantial housing development--there are a few existing residences directly across the street (Broadway) from the Consolidated Edison property line, so application of the criteria proposed to HUD is not entirely inappropriate. Also, if the noise sources from Indian Point 3 were loud enough, the adjacent communities of Verplanck, Buchanan, and portions of Peekskill could be affected.

The proposed HUD criteria do not distinguish between pure tones and broad band noise, but specify the percentages of time that A-weighted

noise levels can be exceeded. To determine compliance with these criteria, the A-weighted noise levels need to be monitored over a period of time, preferably 24 hours. However, because noise levels of sources such as traffic are somewhat random in nature, and because at any location a 24-hour time-history will vary from day to day, an accepted procedure is to record noise levels for 5 to 10-minute time intervals periodically during a representative time period. The representative time period depends, of course, on the nature of the noise for the particular situation.

For the January 20 and 21, 1972, measurements at the Indian Point site, the noise was tape-recorded and these data were then reduced and converted to the format used to determine compliance with the proposed HUD criteria. Note that with this procedure, transient noise sources such as traffic are included, so the results include all noises--transient and steady-state.

The results of these tape-recorded measurements are shown in Figure 4.2-1, superimposed on the proposed HUD criteria. This figure shows that the ambient levels already exceeded the levels allowed by the proposed HUD criteria at Locations 2, 4, and 8 during the time measurements were made. Recall that Location 4 was adjacent to the two Consolidated Edison gas turbines, Location 8 was adjacent to the fossil fueled power station, and Location 2 was within 20 feet of Broadway, which is a thoroughfare with heavy truck and auto traffic. Tape-recorded data for Locations 3 and 5 are incomplete, but the data indicate that Location 3 would fall in the normally acceptable category while Location 5 would fall in the normally unacceptable category. At Location 1, the curve falls close to the dividing line between "normally acceptable" and

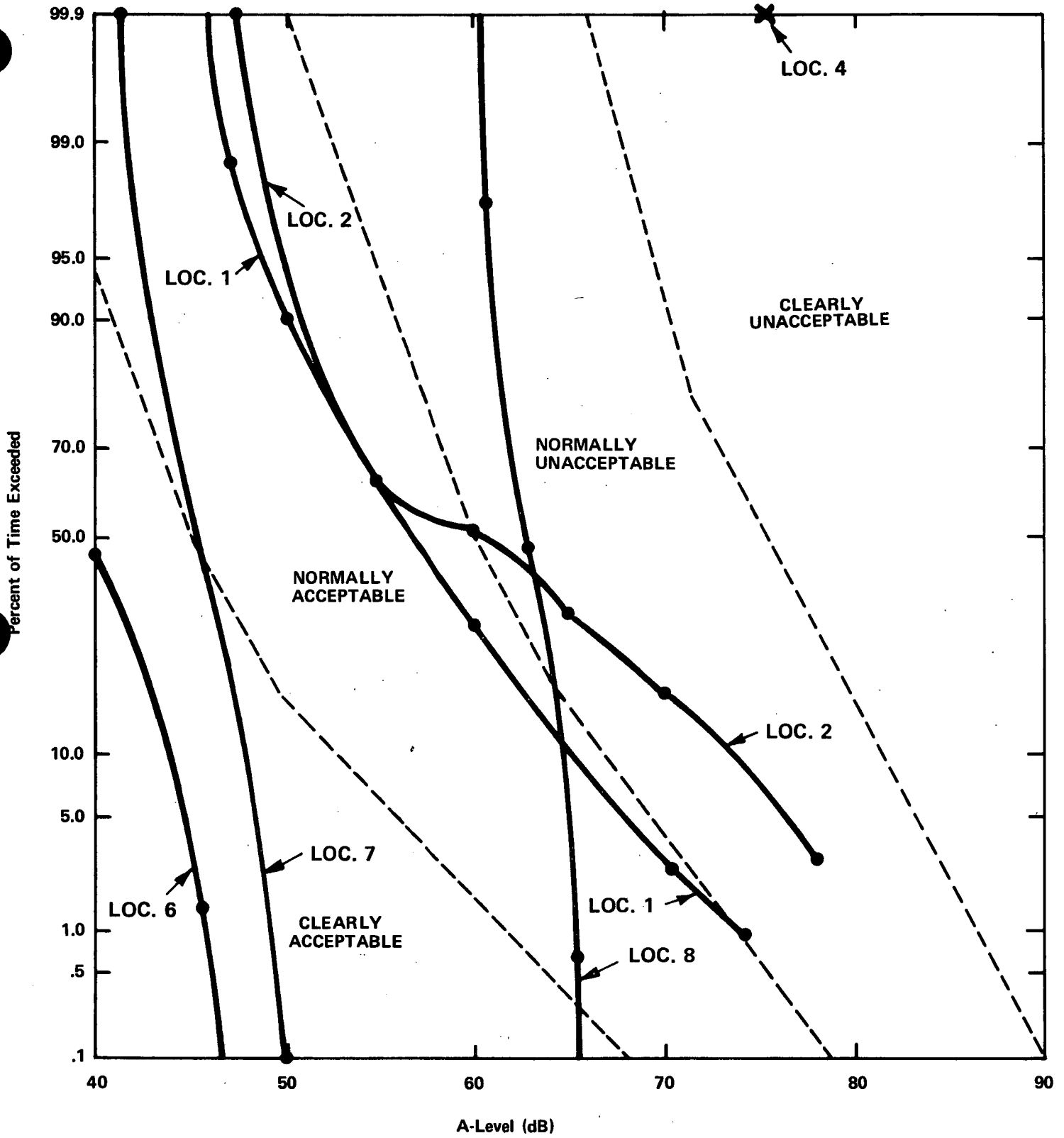


FIGURE 4.2-1. ACOUSTIC DATA DISTRIBUTION

"normally unacceptable" areas. Since the measurements were made during daytime periods of fairly heavy traffic, the curve would be expected to shift to the left slightly to reflect the quieter nighttime traffic in a 24-hour sampling period. Locations 6 and 7 are obviously in the acceptable category. In summary, existing noise levels at Locations 1, 3, 6, and 7 fall in the acceptable category, while levels at Locations 2, 4, 5, and 8 fall in the unacceptable category.

The existing noise levels documented above are those which exist with the Indian Point facility inoperative. However, the design of the Indian Point 3 facility is such that no significant noise sources are expected to be introduced by its operation so that the existing noise levels in the surrounding areas are expected to be virtually the same with Indian Point 3 in operation. Therefore, the expected environmental impact of Alternative A --operation of the Indian Point 3 as presently planned--is zero from the noise standpoint.

Alternative B. Modified Environmental Cost Design

Environmental Cost: About 21 residents subjected to noise levels in the normally unacceptable range, above 50 dBA.

It is expected that the noise generated by a natural draft cooling tower would be almost white (broad-band) in character, and--because the natural draft cooling towers do not employ powered fans to move air--that the noise levels generated will be relatively low. Estimates of the noise emitted from the natural draft cooling towers have been made[4.2b] and the results indicate that the noise levels will be in the normally unacceptable

region for a distance of 2500 feet from the center of the tower complex. Thus, an area of about 0.7 square mile would experience noise levels in the normally unacceptable range, and about 21 residents would be involved.

These costs are in conformance with assumptions made in the guidelines. Studies indicate that the estimated noise at the Broadway property line is 58 dBA and the costs will be zero, in that the expected noise from the two hyperbolic cooling tower will

(a) Not exceed the local noise ordinance of the Village of Buchanan along the Broadway property line.

(b) Be less than the existing background noise level along Broadway due to vehicular traffic which exceeds 60 dBA for more than 50 percent of the time (refer to Figure 4.2-1).

(c) Be within the 65 dBA limit for "Discretionary-Normally Acceptable" category for external noise exposure standards for new construction sites as outlined in the U.S. Housing and Urban Development (HUD) Transmittal Noise 1390.2 (subject: "Noise Abatement and Control: Departmental Policy, Implementation Responsibility, and Standards". Reference 4.2a is a contractor's report to HUD and does not represent official policy.)

(d) Produce broadband white noise (similar to the noise generated by falling rain) that will serve to mask the intrusion of transient environmental noise.

In addition, the noise radiated from the two hyperbolic cooling towers will be limited within the boundary lines of the site with the exception of the Broadway boundary line.

Of all alternatives, the mechanical draft cooling towers will be the noisiest. Ignoring the directional effects of the cell layout, the predicted noise generated by the mechanical draft cooling towers will produce a sound level of 50 dBA at a distance of 5000 feet from the cooling cell complex. This means that an area of approximately 2.8 square miles will be in the unacceptable zones as defined by HUD. This leads to an environmental cost of about 745 residents subjected to unacceptable noise levels. Of this area, approximately 0.1 square mile in the immediate vicinity of the cells will be in the "clearly unacceptable" classification, with the remainder of the unacceptable area falling in the "normally unacceptable" classification. The latter would constitute approximately 4.2 square miles, and encompasses portions of Peekskill, Buchanan, and Verplanck.

These predicted acoustic levels are those which are emitted from the louvered face of the cells. The sound level on the cased face of the cooling cell is expected to be from 5-10 dBA lower, so the corresponding areas will experience lower noise levels. Therefore, the noise levels are conservatively high levels.

The acoustic power generated by the spray pond should be proportional to the hydraulic power dissipated, but insufficient information is available to enable the noise level to be predicted accurately. The character of the noise generated will be almost white (broad-band) in nature.

Alternative C. Plant License Request Design

Environmental Cost: 0 residents, schools, or hospital beds within area having noise above present levels

This alternative is identical to Alternative A.

4.2.2 People (Aesthetics)

The aesthetic appearance or quality of the environment is determined by value judgments made by members of society. Because individuals vary in their perception of the environment, it is often difficult to quantify and reach a consensus of their views. In this report certain aesthetic standards were used that have a sensitivity toward the environment and social values, so that it was possible to analyze aesthetic considerations on a relative basis.

The following process was used to reach the judgments expressed in this section:

(1) The Indian Point site and the area surrounding this site were visited.

(2) The Indian Point site and the area surrounding this site were photographed.

(3) The aesthetic environment of the site and the surrounding area were divided into the appropriate aesthetic components of air, water, biota, man-made structures, and overall aesthetic composition.

(4) Changes in these components from the construction and operation of Indian Point 3 were estimated and then summed to obtain the overall impact on the aesthetic environment.

The aesthetic standards stated in this section were developed for the Bureau of Reclamation to evaluate the environmental impacts of water resource projects. These standards which are listed as value

functions in the Bureau of Reclamation report[4.2c], relate environmental quality to various degrees of aesthetic quality.

Alternative A. Plant As Is

Environmental Cost: Minor

The overall aesthetic impact of Unit 3 of Indian Point is negative in direction but minor in magnitude.

The Indian Point site is located in the Hudson Valley directly on the east shore of the Hudson River. Because of the topography of the area, the site is visible for several miles from vantage points which are distributed in all directions from the site. However, its location at a bend in the river restricts its visibility to just over a mile for those directly on the river.

The land use in the area near the plant is a mixture of relatively small residential communities such as Peekskill, Buchanan, Verplanck; parks and preserves such as the Palisades Interstate Park, Blue Mountain Reservation, Camp Smith; and some industrial developments. Immediately north is the Standard Brands plant, immediately south a complex owned by Georgia Pacific and directly downstream and across the river a five-unit fossil-fueled power plant owned by Orange and Rockland. The land immediately surrounding the site is heavily wooded and is generally aesthetically pleasing. This wooded land creates a buffer zone for the site .

The structures planned for Unit 3 are compatible with the existing structures and, in fact, are even more pleasing aesthetically

because of the absence of additional stacks. The complex of buildings has an unobjectionable simple design and, in fact, the spherical shape of the reactor buildings is an interesting addition to the landscape.

The stack, which was constructed for Unit 1, by its very nature conflicts with the skyline of the area. Its red and white stripes tend to accentuate its vertical deviation. The stack can be viewed from many locations in the area and tends to underscore the entire development. However, there are plans to reduce the stack's height in the near future. This change would improve the aesthetic composition of the entire site.

Transmission lines for Unit 3 will use ornamental poles in place of the usual lattice structures. The use of ornamental poles will reduce the negative impact in all areas except in the town of Buchanan. It is expected that even ornamental poles will create a minor negative impact in the community. The area adjacent to the switching yard and Unit 3 structures will be completely landscaped to make the man-made objects as compatible as possible with the natural environment.

Alternative B. Modified Environmental Cost Design

Environmental Cost: Major

It is expected that the overall impact from the natural-draft tower and the relevant impacts stated in Alternative A on the aesthetic composition of the Hudson Valley would be negative in nature and major in magnitude.

A 500-foot high natural-draft cooling tower is proposed for Indian Point. This tower would be located in an area immediately to the

south of the structures for Units 1, 2, and 3. Some of the natural vegetation in this area would be eliminated with the construction of this tower.

A natural-draft tower would dominate the landscape of the valley and the towns in the immediate vicinity of the site. The tower and its plume would be visible for many miles in all directions from Indian Point. Because many individuals use the Hudson Valley for recreation, these conditions would pose a major conflict with the natural environment and would produce an aesthetically displeasing situation.

The net impact of the mechanical-draft cooling towers on the aesthetics of the area is negative in direction and moderate in magnitude. The towers would be located in an area immediately to the southeast of Units 1, 2, and 3. Because this area is elevated and only partially buffered with natural vegetation, these towers would be visible to individuals near the site. In the placement of these towers, some of the natural vegetation in the area would be removed. The water vapor emissions from these towers and the resulting ground fog would be noticeable from many locations in the valley. In fact, on some days the ground fog would probably cover most of the plant site.

It is expected that the overall impact of the spray pond and the relevant impacts from Alternative A would be negative in direction and moderate in nature. The spray pond would be located in an area southeast of Units 1, 2, and 3. Because this area is elevated and only partially buffered with natural vegetation, it is expected that some of the pond and the pipes would be visible to individuals near the site. The fogging conditions created by the pond would call attention to its location and interaction with the natural environment. These fogging conditions are

also expected to be visible to individuals in the town of Verplanck which is adjacent to the pond.

Alternative C. Plant License Request Design

Environmental Cost: Same as Alternative A

This alternative is identical to Alternative A.

4.2.3 Wildlife

All Alternatives

Environmental Cost: None

The Indian Point Station site is not located on prime quality wildlife habitat nor on any wildlife refuge or preserve. Significant numbers of wildlife will not be displaced by the operation of the station. Therefore, there will be no impact on terrestrial wildlife.

4.2.4 Land, Flood Control

All Alternatives

Environmental Cost: None

As noted in the Indian Point Unit 3 Environmental Report, Section 4.2, flooding at the site is nonexistent. Therefore, the plant has no implications regarding flood control.

References to Section 4.2

(4.2a) Schultz, Theodore J. "Technical Background for Noise Abatement in HUD's Operating Programs", Bolt, Beranek and Newman Report #2005, Cambridge, Massachusetts, September 1970.

(4.2b) Information supplied by Consolidated Edison.

(4.2c) Dee, Norbert, et al, "Environmental Evaluation System for Water Resource Planning", Battelle-Columbus report to U.S. Bureau of Reclamation, Contract 14-06-D-7182, Washington, D.C. (1972).

4.3 Salts Discharged From Cooling Towers

4.3.1 People

Alternative A. Plant As Is

Environmental Cost: 0 lb/ft^2 per year

This alternative uses once through cooling and consequently has no loss of water due to drift. Therefore, no salt discharges to the landscape occur and no threat to ground water can be identified.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0.00006 lb/ft^2 per year

The salt deposition resulting from the cooling alternatives are tabulated in Table 4.3-1 for the sector having the highest deposition and for the entire area between radii of 0-1, 1-2, 2-3, 3-4, 4-5, and 5-10 miles of the site. These values were calculated using (1) estimates[4.3a] of salt deposition for a natural-draft cooling tower located at Indian Point and (2) the factors employed to estimate the dispersion of airborne radioactivity from the site. The radioactivity factors were also used in Section 3.3 to calculate radiation doses and in Section 3.1 to calculate fogging and icing.

The theoretical equations used to estimate salt deposition are based on equations developed for estimating the dispersion and deposition of radioactivity from elevated stacks[4.3b]. The important parameters in these equations are (1) the salt discharge rate into the atmosphere, (2) the effective height of the plume, (3) the distance from the source, and (4) the average ambient weather conditions which include the stability, the wind velocity,

TABLE 4.3-1. SALT DEPOSITION RATES

Alternative	Salt Discharge Rate, lb/year[a]	Salt Deposition Rates, lb/(acre-year)											
		0-1 miles		1-2 miles		2-3 miles		3-4 miles		4-5 miles		5-10 miles	
		Maximum Sector	Entire Circle	Maximum Sector	Entire Circle	Maximum Sector	Entire Circle	Maximum Sector	Entire Circle	Maximum Sector	Entire Circle	Maximum Sector	Entire Circle
AA	0	0	0	0	0	0	0	0	0	0	0	0	0
BB	1.06×10^6	0.3	0.02	0.8	0.07	1.8	0.2	2.7	0.3	2	0.2	0.4	0.03
BC	3.35×10^6	34	10	16	5	8	2	5	1.4	3	1.0	1.1	.5
BD	1.68×10^6	2300	950	0	0	0	0	0	0	0	0	0	0

(a) Drift assumed to be 0.0025 percent of cooling water flow for natural-draft towers, 0.008 percent for mechanical-draft towers, and 0.004 percent for spray ponds.

and the wind direction. The factors for estimating the dispersion of airborne radioactivity are ratios of the ground-level concentration of atmospheric radioactivity at a given point to the rate of radioactivity discharge from the site. Deposition is assumed to be proportional to ground-level concentration so these factors are also applicable to estimating salt deposition. However, the factors[4.3a] were calculated for a ground-level release and for an effective plume height of about 290 feet. These effective heights for radioactivity are, of course, not applicable to the cooling towers. The theoretical equations indicate the logarithm of the radioactivity factor at a given location should be proportional to the square of the effective plume height, and this scaling was used to correct the radioactivity factors for the effective plume heights corresponding to the mechanical-draft cooling towers (about 400 feet). The spray ponds are essentially ground-level releases while the effective plume height for the natural-draft tower is in excess of 1000 feet and this would require extrapolation beyond the confidence of the scaling.

Because of the difficulties in extrapolating the radioactivity factors to the plume height of the natural-draft tower, these factors could not be used with confidence to calculate the salt deposition from the towers. The earlier estimates of salt deposition were for natural-draft tower but these estimates[4.3a] were only for the sector showing the maximum deposition rates and were based on different salt discharge rates from the tower. These earlier estimates[4.3a] were scaled with the salt discharge rates shown in Table 4.3-1 for a natural-draft tower in order to obtain the depositions for the maximum sector. The scaling was directly proportional to the discharge rate. In order to estimate the average deposition rate for the entire area

within given radii, the radioactivity factors were scaled to the effective plume height corresponding to the natural-draft towers. The average factor for all the sectors within the given radii was calculated and the ratio of this average factor to the factor for the maximum sector within the given radii was determined. This ratio was then multiplied by the salt deposition rate for the maximum sector to provide the estimate of the average deposition rate. The calculation of this ratio did not require as much confidence as the direct calculation of the deposition rate so that the scaling with plume height was satisfactory for this purpose.

The salt deposition values for the mechanical-draft towers and the spray ponds were calculated as the product of a salt discharge rate, a deposition velocity equivalent to 5 cm/sec [4.3a], and the radioactivity factor for the given sector and distance from the site. The salt discharge rate used for the 0-1 mile distance was the value at the tower or pond as given in Table 4.3-1. The total amount of salt deposited within one mile was then subtracted from the tower or pond discharge and this difference was used as the salt discharge rate for calculating the deposition within the 1-2 mile radii. This process of reducing the discharge rate was continued until the rate became zero. The results of these calculations indicated that about 5 percent of the salt discharged from mechanical-draft towers would be deposited within 10 miles while all of the salt discharged from spray ponds would be deposited within one mile. The definition of the radioactivity factors was not fine enough to calculate the exact radius within which all of salt from the spray ponds would be deposited. Therefore, the average deposition rates given in Table 4.3-1 for spray ponds were calculated with the assumption that all of the salt would be uniformly deposited on the area enclosed by the one-mile radius.

Intrusion of salts from cooling tower drift into groundwater is considered improbable. The only public water supply served by wells within 5 miles of Indian Point is the Stony Point System, located about 3 miles to the southwest across the river. The total yield of these wells averages about 550 gpm. A few wells, serving private homes, are still in use along the fringes of the area. Both the Stony Point System wells and the private wells are in unconsolidated deposits with depths ranging from 35 to 50 feet. However, on both sides of the river the ground elevations are considerably higher than at the plant site, and water should flow to the river[2.2a].

The data in Table 4.3-1 indicate that the maximum rate of salt deposition from the natural-draft cooling tower will occur 3 to 4 miles from the plant. The rate was calculated to be about 2.7 lb salt per acre per year which is equivalent to about 0.00006 lb/ft^2 per year. Percolation of this material into the ground will depend upon rainfall. The annual rainfall in this region averages about 36 inches[4.3c], and so the average salt concentration in percolating groundwater would be about 0.33 mg/liter. Since this is a factor of 760 below permissible water quality criteria for chloride and sulfate (250 mg/liter) as recommended for public water supplies[4.3d], any salts from the natural-draft cooling tower that might reach underground wells will have negligible effect on the water supply.

The calculated deposition rates from the mechanical-draft cooling towers, while appreciably higher than for a natural-draft cooling

tower, would still result in peak average salt concentrations in percolating groundwater at one mile of 4.2 mg/liter. The maximum deposition is 34 lb/acre per year (0.00078 lb/ft^2 per year) and occurs within one mile of the plant. No effect on local groundwater supplies would occur from these salt concentrations. The rate calculations for the spray pond indicate that the deposition will be confined to an area within one mile of the site and the maximum deposition will be 2300 lb/acre per year (0.052 lb/ft^2 per year). Since there is no use of well water within one mile of the site, no loss of water supply will occur.

Alternative C. Plant License Request Design

Environmental Cost: 0 lb/ft^2 per year

This alternative is identical to Alternative A.

4.3.2 Plants and Animals

Alternative A. Plant As Is

Environmental Cost: 0 acres

Since once-through ccoling will not result in the deposition of salts in the area, there will be no environmental costs to plant or animal life associated with this alternative.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 acres

Although it was possible to obtain estimates of the magnitude of salt deposition for the various cooling alternatives, it was not

possible to obtain enough specific data to allow a detailed assessment of the potential effects of the salt deposited on the vegetation and animal life within the plant's sphere of influence. However, data from highway salting research indicates that salt deposition rates of 500 lb/acre/year could be detrimental to roadside vegetation and deposition rates of 1000 lb/acre/year would cause damage to roadside vegetation. Using this range of deposition rates and the date given in Table 4.3-1 for the various cooling alternatives, estimates were made for the acreage which could suffer potential detrimental effects from salt deposition.

The data in Table 4.3-1 show no salt deposition rates in excess of 500-1000 lbs/acre/year for the cooling towers and thus, there will be no environmental costs to plant life in the area associated with these alternatives.

As shown in Table 4.3-1, the predicted salt deposition rates from the spray pond exceed the 500-1000 lbs/acre/year reported to have detrimental effects on plant life. Furthermore, the calculations predict that all the salt would be deposited within a 0-1 mile radius of the spray pond. Consequently, this alternative could be expected to present an extreme hazard to terrestrial plant life particularly in the immediate plant site environs, and to a lesser extent, up to one mile from the spray pond. Within the 0-1 mile radius of the spray pond there are some 1,206 acres of land with approximately equal utilization by industrial activities and residential usage. The environmental cost to the plant life on these 1,206 acres from the spray pond alternative could be potentially substantial.

Alternative C. Plant License Request Design

Environmental Cost: 0 acres

This alternative is identical to Alternative A.

4.3.3 Property Resources

Alternative A. Plant As Is

Environmental Cost: 0 dollars/year

Since once-through cooling does not discharge any salt into the air, there will be no degradation of property resources associated with this alternative.

Alternative B. Modified Environmental Cost Design

Environmental Cost: 0 dollars/year

The estimates of salt deposition rates from the various cooling alternatives were given in Table 4.3-1 and the methods used to arrive at these estimates were discussed in Section 4.3.1. The salt deposition rates given in Table 4.3-1 were used to indicate the extent of possible damage to the property resources surrounding the plant site.

Through a review of the literature and contacts with a number of local real estate appraisal and consulting firms, efforts were made to obtain data for comparable coastal and in-land communities which could possibly provide guidance in the assessment of the impact of salt deposition on property resources within the sphere of influence of the Indian Point site. These efforts

did not reveal any data which would enable a reasonable assessment of the detrimental effects on property resources. Therefore, some general comments on the possible consequences of salt deposition are discussed below.

The effects of salt spray impinging upon the structures and moveable property in the area would be in the form of increased maintenance and replacements costs. Any exposed metallic surfaces (including such items as equipment, motor vehicles, ornamental iron work, spouting, etc.) would be subjected to accelerated rates of deterioration beyond that of normal weathering effects for the area. Consequently, it would require increased maintenance activity to protect such property from deterioration due to the corrosive action of the deposited salts. Residential dwellings in the area of heavy salt deposition would also require more frequent paintings (possibly every year, rather than 2-3 years between paintings). Even more subtle effects might occur in areas of heavy salt deposition. For instance, water mains, pipelines, and highway culverts may be affected, since the ditches to accommodate these structures can act as subsurface drainage channels and concentrate the surface runoff around the pipes.

It can be seen from Table 4.3-1 that salt deposition rates from a natural-draft cooling tower are relatively low. The highest deposition rate occurs in the maximum sector of the 3-4 mile radius, which is almost entirely over the Hudson River proper. Consequently, there would be very little, if any, property resources in this sector to be exposed to the deposited salt.

Of the other cooling subalternatives, the spray pond alternative represents the greatest potential threat to property resources in the area. As seen from Table 4.3-1, it is predicted that all the salt

will be deposited in a one-mile radius from the plant site. While most of the salt should be deposited close in to the spray pond, the town of Verplanck is located within one-mile radius and would be expected to receive some of the deposited salts. Thus, the environmental cost to property resources in the area would be moderate from the spray ponds.

The mechanical-draft cooling tower would have the next greatest potential for damage to surrounding property resources. As seen from Table 4.3-1, the highest salt deposition rates occur in the maximum sectors of the 0-1 mile radius which includes the town of Verplanck and the 1-2 mile radius. Consequently, some damage to property resources in this area could occur from the salts deposited by the mechanical-draft cooling towers and this cost would also be moderate.

Alternative C. Plant License Request Design

Environmental Cost: 0 dollars/year

This alternative is identical to Alternative A.

References to Section 4.3

(4.3a) Information supplied by Consolidated Edison.

(4.3b) I. Van der Hoven, "Deposition of Particles and Gases", in Meteorology and Atomic Energy", D. H. Slade, ed., U.S. AEC Report No. TID-24190.

(4.3c) U.S. Bureau of the Census, "Statistical Abstracts of the United States--1971", 92nd Annual Edition, Washington, D.C., 1971, Table No. 289, p. 179.

(4.3d) "Water Quality Criteria--Report of the National Technical Advisory Committee to the Secretary of the Interior", Washington, D.C., April 1, 1968, p. 20.

4.4 Other Land Impacts

No other land impacts have been identified.

4.5 Combined or Interactive Effects

There is no evidence that measures of combined effects of a number of impacts are different from measures of the separate impacts.

APPENDIX A

DOSE CONVERSION FACTORS USED IN RADIOLOGICAL IMPACT CALCULATION

TABLE A-1. ANNUAL RELEASE OF INDIVIDUAL RADIONUCLIDES WHICH WOULD DELIVER DOSE LIMITS

Pathway for Releases	Critical Nuclide	Critical Organ	Point of Exposure	Indi-vidual	Unit	Ci/yr To Give Dose Limit	Ci/yr To Give 1% of Dose Limit	Dose Limit (mrem/year)
Drinking water	H-3	Whole Body	Chelsea	Adult	1	5.0×10^{8}	5.0×10^{6}	500
					2	9.6×10^{7}	9.6×10^{5}	
	I-131	Thyroid		Child	1	1.3×10^{5}	1.3×10^{3}	1500
					2	1.2×10^{5}	1.2×10^{3}	
Fish consumption	H-3	Whole Body	Vicinity Indian Pt.	Adult	1	1.6×10^{9}	1.6×10^{7}	500
					2	1.3×10^{9}	1.3×10^{7}	
	Cs-137	Whole Body			1	2.1×10^{5}	2.1×10^{3}	
					2	2.0×10^{5}	2.0×10^{3}	
	Cs-134	Whole Body			1	9.0×10^{4}	9.0×10^{2}	
					2	9.3×10^{4}	9.3×10^{2}	
	I-131	Thyroid		Adult	1	2.0×10^{5}	2.0×10^{3}	1500
					2	4.2×10^{5}	4.2×10^{3}	
Swimming or Boating	Mo-99, I-131 I-133, I-135 Cs-134, Cs-137	Whole Body	Verplanck	Any age	1	1.2×10^{6}	1.2×10^{4}	500
					2	1.3×10^{6}	1.3×10^{4}	
			Discharge Point		1	5.8×10^{5}	5.8×10^{3}	
					2	5.7×10^{5}	5.7×10^{3}	
Sunbathing	Cs-137	Whole Body	Lent's Cove	Any age	1	1.8×10^{3}	1.8×10^{1}	500
					2	1.8×10^{3}	1.8×10^{1}	
	Cs-134	Whole Body	Lent's Cove	Any age	1	1.1×10^{4}	1.1×10^{2}	
					2	1.1×10^{4}	1.1×10^{2}	

TABLE A-1. (Continued)

Atmospheric Releases	Critical Nuclide	Critical Organ	Point of Exposure	Indi-vidual	Unit	Ci/yr To Give Dose Limit	Ci/yr To Give 1% of Dose Limit	Dose Limit (mrem/year)
External Gamma	Xe-133	Whole Body	Site Boundary	Adult	1 2	2.0×10^{7} 4.8×10^{6}	2.0×10^{5} 4.8×10^{4}	500
External Beta	Kr-85	Skin	Site Boundary	Adult	1 2	1.3×10^{7} 3.3×10^{5}	1.3×10^{5} 3.3×10^{3}	500
	Xe-133	Skin	Site Boundary	Adult	1 2	3.6×10^{7} 5.9×10^{5}	3.6×10^{5} 5.9×10^{3}	500
Milk Consumption	I-131	Thyroid	Nearest Dairy Farm	Child	1 2	1.5×10^{4} 1.5×10^{3}	1.5×10^{2} 1.5×10^{1}	1500
Inhalation	I-131	Thyroid	Site Boundary	Child	1 2	5.2×10^{3} 1.1×10^{2}	$5.2 \quad 10^{1}$ 1.1	1500

APPENDIX B

ALTERNATIVE PLANT DESIGN SUMMARY TABLES

ALTERNATIVE PLANT DESIGN SUMMARY			A	B	C
			Plant As Is (Base Design)	Plant With Modified Environmental Impact	Plant Operating License Request
IDENTIFICATION OF SUBSYSTEMS					
Alternative Cooling Systems (I)			A	B	A
Alternative Rad Waste System (II)			A	B	A
Alternative Chemical Effluent Systems (III)			A	B	A
Alternative _____ System (specify) (IV)					
GENERATING COST	Present Worth	(Million Dollars)	319.460	409.920	319.460
	Annualized	(Million Dollars)	33.183	42.520	33.183
LOST CAPACITY (MWe) Average/Peak			--	38/83	--
INCREMENTAL ENVIRONMENTAL EFFECTS		UNITS			
Primary Impact					
Natural Surface Water Body					
1.1 Cooling Water Intake Structure	1.1.1 Fish	lb/yr	11,200	400	11,200
1.2 Passage Through the Condenser and Retention in Closed-Cycle Cooling Systems	1.2.1 Primary Producers & Consumers	lb/yr	370	33	370
	1.2.2 Fish	lb/yr	0	0	0
1.3 Discharge Area and Thermal Plume	1.3.1 Water Quality, Physical	Acres* Acre-ft			
	1.3.2 Oxygen Availability	Acre-ft	0	0	0

*5F isotherm data; 2F and 3F data in Table 1.3-1 in text.

		UNITS	A	B	C
	1.3.3 Aquatic Biota	lb/yr			
	1.3.4 Wildlife (including birds, aquatic and amphibious mammals, and reptiles)	Acres	0	0	0
	1.3.5 Fish, Migration	lb/yr	0	0	0
1.4 Chemical Effluents	1.4.1 Water Quality, Chemical	Ac-ft day %	0 0	0 0	0 0
	1.4.2 Aquatic Biota	lb/yr	0	0	0
	1.4.3 Wildlife (including birds, aquatic and amphibious mammals, and reptiles)	Acres	0	0	0
	1.4.4 People	Days Acres	0	0	0
1.5 Radionuclides Discharged to Water Body	1.5.1 Aquatic Organisms Rem/yr	Benthos	$2x10^{-1}$	$3.4x10^{-1}$	$2x10^{-1}$
		Fish	$3x10^{-4}$	$5.1x10^{-4}$	$3x10^{-4}$
	1.5.2 People, External	Rem/yr/person	$2.2x10^{-5}$	$3.7x10^{-5}$	$2.2x10^{-5}$
		Man-rem/yr	2.5	4.3	2.5
	1.5.3 People, Ingestion	Rem/yr/person	$7.7x10^{-7}$	$7.7x10^{-7}$	$7.7x10^{-7}$
		Man-rem/yr	0.7x7	0.7x7	0.7x7
1.6 Consumptive Use (evaporative losses)	1.6.1 People	Gal/yr	0	0	0
	1.6.2 Property	Acre-ft/yr	0	0	0
1.7 Other Impacts			None	None	None
1.8 Combined or Interactive Effects			None	None	None

		UNITS	A	B	C
2. Groundwater					
2.1 Raising/Lowering of Groundwater Levels	2.1.1 People	Gal/yr	0	0	0
	2.1.2 Plants	Acres	0	0	0
2.2 Chemical Contamination of Groundwater	2.2.1 People	Gal/yr	0	0	0
	2.2.2 Plants	Acres	0	0	0
2.3 Radionuclide Contamination of Groundwater	2.3.1 People	Rem/yr/person	0	0	0
		Man-rem/yr	0	0	0
	2.3.2 Plants and Animals	Rad/yr	0	0	0
2.4 Other Impacts on Groundwater			None	None	None
3. Air					
3.1 Fogging & Icing (caused by evaporation and drift)	3.1.1 Ground Transportation	Hrs/yr	0	0	0
	3.1.2 Air Transportation	Hrs/yr	0	0	0
	3.1.3 Water Transportation	Hrs/yr	0	0	0
	3.1.4 Plants	Acres	0	0	0
3.2 Chemical Discharge to Ambient Air	3.2.1 Air Quality, Chemical	%	0	0	0
		lb/yr	375,000 SO_2	375,000 SO_2	375,000 SO_2
	3.2.2 Air Quality, Odor	--	None	None	None
3.3 Radionuclides Discharged to Ambient	3.3.1 People, External	Rem/yr/person	$3.5\gamma x10^{-3}$	$3.5\gamma x10^{-3}$	$3.5\gamma x10^{-3}$
		Man-rem/yr	~1	~1	~1

		UNITS	A	B	C
3.3 Radionuclides Discharged to Ambient Air (cont'd.)	3.3.2 People, Ingestion	Rem/yr/person Man-rem/yr	1.5×10^{-3} 57	1.5×10^{-3} 57	1.5×10^{-3} 57
	3.3.3 Plants and Animals	Rem/yr	0.36	0.36	0.36
3.4 Other Impacts on Air	3.4.1. Migratory Birds		None	None	None
4. Land					
4.1 Pre-emption of Land	4.1.1 Land, Amount	Acres	0	0	0
4.2 Plant Construction and Operation	4.2.1 People (amenities)	Residents	0	21	0
	4.2.2 People (aesthetics)	--	Minor	Major	Minor
	4.2.3 Wildlife		None	None	None
	4.2.4 Land, Flood Control	--	None	None	None
4.3 Salts Discharged from Cooling Towers	4.3.1 People	lb/ft^2 per yr	0	0.00006	0
	4.3.2 Plants and Animals	Acres	0	0	0
	4.3.3 Property Resources	$/yr	0	0	0
4.4 Other Land Impacts			None	None	None
4.5 Combined or Interactive Effects			None	None	None

ALTERNATIVE COOLING SYSTEMS			A	BB	BC	BD
INCREMENTAL GENERATING COST	Present Worth (Million Dollars)		--	90.460	96.980	111.720
	Annualized (Million Dollars)		--	9.397	10.074	11.605
LOST CAPACITY (MWe) Average/Peak			--	38/83	37/64	46/85
INCREMENTAL ENVIRONMENTAL EFFECTS		UNITS				
Primary Impact	Population or Resource Affected					
Natural Surface Water Body						
1.1 Cooling Water Intake Structure	1.1.1 Fish	lb/yr	11,200	400	400	400
1.2 Passage Through the Condenser and Retention in Closed-Cycle Cooling Systems	1.2.1 Primary Producers & Consumers	lb/yr	370	33	33	76
	1.2.2 Fish	lb/yr	0	0	0	0
1.3 Discharge Area and Thermal Plume	1.3.1 Water Quality, Physical	Acres* / Ac-ft				
	1.3.2 Oxygen Availa-bility	Ac-ft	0	0	0	0

*5F isotherm data; 2F and 3F data in Table 1.3-1 in text.

		UNITS	A	BB	BC	BD
	1.3.3 Aquatic Biota	lb/yr				
	1.3.4 Wildlife (including birds, aquatic and amphibious mammals, and reptiles)	Acres	0	0	0	0
	1.3.5 Fish, Migration	lb/yr	0	0	0	0
1.4 Chemical Effluents	1.4.1 Water Quality, Chemical	Ac-ft/day %	0 0	0 0	0 0	0 0
	1.4.2 Aquatic Biota	lb/yr	0	0	0	0
	1.4.3 Wildlife (including birds, aquatic and amphibious mammals, and reptiles)	Acres	0	0	0	0
	1.4.4 People	**Days Acres**	**0 0**	**0 0**	**0 0**	**0 0**
1.5 **Radionuclides Discharged to Water Body**	**1.5.1 Aquatic Organisms** Rem/yr	**Benthos**	$2x10^{-1}$	$3.4x10^{-1}$	$3.4x10^{-1}$	$3.4x10^{-1}$
		Fish	$3x10^{-4}$	$5x10^{-4}$	$5x10^{-4}$	$5x10^{-4}$
	1.5.2 People, External	Rem/yr/person	$2.2x10^{-5}$	$3.7x10^{-5}$	$3.7x10^{-5}$	$3.7x10^{-5}$
		Man-rem/yr	2.5	4.3	4.3	4.3
	1.5.3 People, Ingestion	Rem/yr/person	$7.7x10^{-7}$	$7.7x10^{-7}$	$7.7x10^{-7}$	$7.7x10^{-7}$
		Man-rem/yr	0.7x7	0.7x7	0.7x7	0.7x7
1.6 Consumptive Use (evaporative losses)	1.6.1 People	Gal/yr	0	0	0	0
	1.6.2 Property	Acre-ft/yr	0	0	0	0
1.7 Other Impacts			None	None	None	None
1.8 Combined or Interactive Effects			None	None	None	None

		UNITS	A	BB	BC	BD
2. Groundwater						
2.1 Raising/Lowering of Groundwater Levels	2.1.1 People	Gal/yr	0	0	0	0
	2.1.2 Plants	Acres	0	0	0	0
2.2 Chemical Contamination of Groundwater	2.2.1 People	Gal/yr	0	0	0	0
	2.2.2 Plants and Animals	Acres	0	0	0	0
2.3 Radionuclide Contamination of Groundwater	2.3.1 People	Rem/yr/person	0	0	0	0
		Man-rem/yr	0	0	0	0
	2.3.2 Plants and Animals	Rad/yr	0	0	0	0
2.4 Other Impacts on Groundwater			None	None	None	None
3. Air						
3.1 Fogging & Icing (caused by evaporation and drift)	3.1.1 Ground Transportation	Hrs/yr	0	0	88	4,643
	3.1.2 Air Transportation	Hrs/yr	0	0	88	3,679
	3.1.3 Water Transportation	Hrs/yr	0	0	175	6,044
	3.1.4 Plants	Acres	0	0	0	Moderate
3.2 Chemical Discharge to Ambient Air	3.2.1 Air Quality, Chemical	%	0	0	0	0
		lb/yr	375,000	375,000	375,000	375,000
	3.2.2 Air Quality, Odor	--	None	None	None	None
3.3 Radionuclides Discharged to Ambient	3.3.1 People, External	Rem/yr/person	3.58×10^{-3}	3.58×10^{-3}	3.58×10^{-3}	3.58×10^{-3}
		Man-rem/yr	~1	~1	~1	~1

		UNITS	A	BB	BC	BD
3.3 Radionuclides Discharged to Ambient Air (cont'd.)	3.3.2 People, Ingestion	Rem/yr/person	1.5×10^{-3}	1.5×10^{-3}	1.5×10^{-3}	1.5×10^{-3}
		Man-rem/yr	57	57	57	57
	3.3.3 Plants and Animals	Rem/yr	0.36	0.36	0.36	0.36
3.4 Other Impacts on Air	3.4.1. Migratory Birds	--	None	None	None	None
4. Land						
4.1 Pre-emption of Land	4.1.1 Land, Amount	Acres	0	0	0	0
4.2 Plant Construction and Operation	4.2.1 People (amenities)	Residents	0	21	745	Minor
	4.2.2 People (aesthetics)	--	Minor	Major	Moderate	Moderate
	4.2.3 Wildlife	Acres	None	None	None	None
	4.2.4 Land, Flood Control	--	None	None	None	None
4.3 Salts Discharged from Cooling Towers	4.3.1 People	lb/ft^2 per yr	0	0.00006	0.00078	0.05
	4.3.2 Plants and Animals	Acres	0	0	0	1,206
	4.3.3 Property Resources	$/yr	0	0	Moderate	Moderate
4.4 Other Land Impacts			None	None	None	None
4.5 Combined or Interactive Effects			None	None	None	None

Regulatory File Cy.

INDIAN POINT UNIT NO. 3
SUPPLEMENT 7
INSTRUCTION SHEET

Received w/Ltr Dated 4-18-73

Insert

Questions and Answers on
"NEED FOR POWER" in
APPENDIX FF

2639

SUPP. 7
4/73

VI. NEED FOR POWER

Question VI.1

The dates and duration of emergency load reductions, percent installed reserves, and date of peak load day for calendar year 1968 through 1972 should be provided.

Answer:

The dates and duration of voltage reductions for calendar years 1968 through 1972 are shown on the attached Tables VI.1-1 through VI.1-5. Additional information is included in the response to Question VI.7 for September 22, 1970, the one occasion on which disconnection of customer load became necessary after reaching the maximum 8% voltage reduction. The dates of peak load days, actual peak loads, total installed capacity, installed reserves and percent installed reserves are shown on the attached Table VI.1-6 for the calendar years 1968 through 1972.

TABLE VI. 1-1

1972 - SYSTEM VOLTAGE REDUCTION PROGRAMS

Date	Time		Amount
	From	To	
May 24	12:24 P.M.	1:19 P.M.	3%
July 17	1:10 P.M.	4:50 P.M.	3%
	* 4:50 P.M.	5:55 P.M.	3%
	* 5:55 P.M.	9:30 P.M.	5%
	** 3:30 P.M.	4:20 P.M.	5%
	** 4:20 P.M.	10:10 P.M.	8%
July 18	3:08 P.M.	5:05 P.M.	5%
July 20	3:10 P.M.	5:10 P.M.	5%
August 24	2:12 P.M.	4:47 P.M.	5%
August 25	12:05 P.M.	5:00 P.M.	5%

*5 Substations only

**Greenwood (Brooklyn) Substation only

TABLE VI. 1-2

1971 SYSTEM VOLTAGE REDUCTION PROGRAMS

Date	From	To	Amount	Date	From	To	Amount
Jan. 18	3:00 PM	6:35 PM	5%	Sept. 9	***3:07 PM	4:37 PM	3%
	6:35 PM	6:47 PM	3%				
Jan. 21	4:00 PM	6:00 PM	5%				
	6:00 PM	6:18 PM	3%				
Jan. 27	4:00 PM	7:35 PM	5%				
	7:35 PM	8:15 PM	3%				
Jan. 28	10:00 AM	6:55 PM	5%				
	6:55 PM	7:45 PM	3%				
Feb. 1	8:45 AM	9:27 AM	3%				
	9:27 AM	9:15 PM	5%				
	9:15 PM	11:05 PM	3%				
Feb. 2	8:00 AM	8:21 PM	5%				
Feb. 3	8:00 AM	6:32 PM	5%				
	6:32 PM	7:04 PM	3%				
Feb. 5	9:05 AM	11:25 AM	3%				
	11:25 AM	2:10 PM	5%				
	2:10 PM	2:30 PM	3%				
May 19	8:05 AM	9:00 AM	3%				
June 7	*4:15 PM	5:05 PM	3%				
June 30	2:00 PM	5:35 PM	3%				
July 1	**2:35 PM	4:05 PM	3%				
July 7	3:28 PM	5:30 PM	5%				
	5:30 PM	5:45 PM	3%				
Aug. 18	4:33 PM	5:03 PM	8%				
	5:03 PM	5:15 PM	3%				

*At the request of the NYPP

**System Generating Station and eight substations only

***System Generating Stations and some bulk substations only

TABLE VI.1-3

1970 SYSTEM VOLTAGE REDUCTION PROGRAMS

DATE	FROM	TO	AMOUNT
Jan. 9th	9:00 AM	12:20 PM	3%
June 11th	1:55 PM	4:46 PM	3%
July 27th	1:15 PM	5:00 PM	3%
July 28th	9:40 AM	1:15 PM	3%
	1:15 PM	5:40 PM	5%
July 29th	10:08 AM	1:43 PM	3%
	1:43 PM	5:00 PM	5%
July 30th	10:10 AM	4:50 PM	3%
	*11:08 AM	4:50 PM	5%
July 31st	10:05 AM	4:50 PM	3%
Aug. 13th	**10:15 AM	11:50 AM	3%
	11:50 AM	12:47 PM	3%
	12:47 PM	5:01 PM	5%
Aug. 14th	9:55 AM	5:15 PM	3%
	**10:00 AM	5:15 PM	5%
Aug. 17th	9:42 AM	1:00 PM	3%
	1:00 PM	3:30 PM	5%
	3:30 PM	3:45 PM	8%
	3:45 PM	5:08 PM	5%
Aug. 20th	3:00 PM	5:20 PM	3%
Sept. 4th	10:50 AM	1:35 PM	3%
	1:35 PM	4:41 PM	5%
	4:41 PM	4:54 PM	3%
Sept. 22nd	11:40 AM	1:00 PM	3%
	1:00 PM	2:35 PM	5%
	2:35 PM	4:35 PM	8%
	4:35 PM	6:00 PM	5%
	6:00 PM	6:13 PM	3%
	7:00 PM	8:40 PM	5%
	**8:15 PM	8:40 PM	3%
	8:40 PM	9:10 PM	3%
Sept. 23rd	8:55 AM	9:10 AM	3%
	9:10 AM	9:25 AM	5%
	9:25 AM	5:15 PM	8%
	5:15 PM	7:55 PM	5%
	** 7:55 PM	8:23 PM	5%
	7:55 PM	8:55 PM	3%
Sept. 24th	8:56 AM	9:25 AM	3%
	** 9:00 AM	9:25 AM	5%
	9:25 AM	5:40 PM	5%
	5:40 PM	6:15 PM	3%
Sept. 25th	1:10 PM	1:23 PM	3%
	** 1:18 PM	1:23 PM	5%
	1:23 PM	5:00 PM	5%
	5:00 PM	5:15 PM	3%

*Six Downtown Manhattan Substations and System Generating Stations only.

**System Generating Stations only.

TABLE VI. 1-4

1969 - SYSTEM VOLTAGE REDUCTION PROGRAMS

Date	Time From	Time To	Amount
May 29th	3:15 PM	5:05 PM	3%
June 12th	3:00 PM	4:40 PM	3%
June 13th	1:30 PM	3:10 PM	3%
June 20th	10:25 AM	4:30 PM	3%
July 17th	12:45 PM	4:40 PM	3%
	* 4:20 PM	4:40 PM	5%
July 18th	9:17 AM	4:20 PM	3%
Aug. 4th	8:35 AM	9:20 AM	3%
	9:20 AM	9:28 AM	5%
	9:28 AM	1:40 PM	8%
	1:40 PM	5:00 PM	3%
Sept. 2nd	8:55 AM	3:25 PM	3%
	** 9:15 AM	12:25 PM	5%
Sept. 8th	9:40 AM	10:15 AM	3%
	10:15 AM	11:00 AM	5%
	11:00 AM	12:45 PM	8%
	12:45 PM	2:28 PM	5%
	2:28 PM	3:05 PM	3%

*Manhattan Bulk Substations Only.
**Eleven Downtown Manhattan Substations Only.

TABLE VI. 1-5

1968 - SYSTEM VOLTAGE REDUCTION PROGRAMS

Date	Time From	Time To	Amount
July 18	1:09 P.M.	5:10 P.M.	3%
July 23	9:20 A.M.	4:10 P.M.	3%
	4:10 P.M.	4:50 P.M.	5%
	4:50 P.M.	5:10 P.M.	3%
Aug. 20	3:40 P.M.	3:50 P.M.	3%
	3:50 P.M.	4:09 P.M.	5%
	4:09 P.M.	4:45 P.M.	3%

February 1973

TABLE VI. 1-6

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

% INSTALLED RESERVE ON PEAK LOAD DAYS

YEAR	DATE	TOTAL INSTALLED CAPACITY(1)	ACTUAL PEAK LOAD(2)	INSTALLED RESERVE	
				MW	%
1968	July 17	7497	6960	537	7.7
1969	July 17	8143	7266	877	12.1
1970	Aug. 28	8957	7041	1916	27.2
1971	July 1	8528	7719	809	10.5
1972	July 19	8826	7872	954	12.1

(1) Excludes Firm Purchases.

(2) Does not include effect of voltage reduction.

February 1973

Question VI.2

The following table for the individual generating station capability for your total system should be completed.

Unit Name	Location	Type	Date Installed	Dependable Capacity (KW) Summer	Winter

ANSWER:

Con Edison's January 31, 1973 Capacity Sheets are attached as Tables VI.2-1 through VI.2-3. These tables list the summer and winter dependable capacity of the Con Edison system by individual units and stations and by type of capacity. A list of Con Edison turbo-generators and their service dates is attached as Table VI.2-4.

TABLE VI.2-1

CONSOLIDATED EDISON SYSTEM

ELECTRIC GENERATING STATION CAPACITY

BASELOAD AND NUCLEAR

STATION	BOILERS: BOILER NUMBER OR ROW NUMBER	METHOD OF FIRING (A)	NUMBER OF BOILERS	STEAMING RATE PER BOILER MLBS/HR: MAXIMUM	STEAMING RATE: SUSTAINED	EQUIVALENT ELECTRIC CAPACITY PER BOILER MW: MAXIMUM SUMMER	MAXIMUM WINTER	SUSTAINED SUMMER	SUSTAINED WINTER	TURBO-GENERATORS: UNIT NUMBER	NAME PLATE RATING MW: 25 CYCLE	60 CYCLE	TOTAL	OPERATING CAPACITY MW: MAXIMUM SUMMER	MAXIMUM WINTER	SUSTAINED SUMMER	SUSTAINED WINTER	FREQUENCY CHANGER RATING MW	TOTAL STATION RATING-MW: MAXIMUM CAPACITY MW GROSS SUMMER	MAXIMUM GROSS WINTER	MAXIMUM NET SUMMER	MAXIMUM NET WINTER	HOUSE TRANSFORMER LOAD MW	SUSTAINED CAPACITY MW GROSS SUMMER	SUSTAINED GROSS WINTER	SUSTAINED NET SUMMER	SUSTAINED NET WINTER
ARTHUR KILL	20	O-P	1	2480	2480	325	340	325	340	2		335	335	325	340	325	340										
	30	O-P	1	3495	3150	505	515	475	485	3		491	491	505	515	475	485										
TOTAL			2			830	855	800	825	2		826	826	830	855	800	825		830	855	806	831	24	800	825	776	801
ASTORIA	10	O-G-P	1	1325	1250	180	183	170	173	1		180	180	180	183	170	173										
	20(B)	O-G-P	1	1250	1250	170	173	170	173	2		180	180	170	173	170	173										
	30	O-G-P	1	2580	2480	390	398	354	361	3		335	335	390	398	354	361										
	40	O-P	1	2675	2465	385	393	355	363	4		380	380	385	393	355	363										
	50	O-P	1	2750	2540	395	403	365	373	5		380	380	395	403	365	373										
TOTAL			5			1520	1550	1414	1443	5		1455	1455	1520	1550	1414	1443		1520	1550	1458	1488	62(L)	1414	1443	1354	1383
BOWLINE POINT	1	O	1	4200	4200	624	624	624	624	1		550	550	624	624	624	624										
CON ED SHARE			1			416	416	416	416	1		367	367	416	416	416	416		416	416	400	400	16(K)	416	416	400	400
EAST RIVER H.P.	50	O-G	1	1200	1145	134	138	129	133	5		137	137	134	138	129	133										
	60	G	1	1200	1145	140	144	135	137	6		137	137	140	144	135	137										
	70	O-G	1	1350	1275	176	180	171	175	7		180	180	176	180	171	175										
TOTAL			3			450	462	435	445	3		454	454	450	462	435	445		450	462	432	444	18	435	445	417	427
RAVENSWOOD	10	O-G	1	2730	2670	415	420	382	387	1		363	363	415	420	382	387										
	20	O-G	1	2730	2670	411	416	380	385	2		363	363	411	416	380	385										
	30(N)	O-P	1	3500	3300	500	500	475	475	3		1000(E)	1000(E)	1000	1000	950	950										
	30(S)	O-P	1	3500	3300	500	500	475	475																		
TOTAL			4			1826	1836	1712	1722	3		1726	1726	1826	1836	1712	1722		1826	1836	1778	1788	48	1712	1722	1664	1674
ROSETON																											
TOTAL																											
TOTAL BASE LOAD			15			5042	5119	4777	4851	14		4828	4828	5042	5119	4777	4851		5042	5119	4874	4951	168(L)	4777	4851	4611	4685
TOTAL PEAK LOAD (F)			49(C)			1849	1914	1813	1875	35	622	1584	2206	1838	1907	1823	1896	246(J)	1596	1655	1499	1558	97	1566	1629	1469	1532
TOTAL CONVENTIONAL			64			6891	7033	6590	6726	49	622	6412	7034	6880	7026	6600	6747	246(J)	6638	6774	6373	6509	265(L)	6343	6480	6080	6217
INDIAN POINT	11-14	N	4	582	582	280	285	280	285	1		275	275	277	282	277	282										
	11-12	O	2(D)	1164	1164																						
TOTAL			4			280	285	280	285	1		275	275	277	282	277	282		277	282	257	262	20	277	282	257	262
TOTAL NUCLEAR			4			280	285	280	285	1		275	275	277	282	277	282		277	282	257	262	20	277	282	257	262
TOTAL			68			7171	7318	6870	7011	50	622	6687	7309	7157	7308	6877	7029	246(J)	6915	7056	6630	6771	285(L)	6620	6762	6337	6479
GAS TURBINES (G)										46		2347	2347	2289	2862	2096	2690	30(H)	2289	2862	2289	2862	0	2096	2690	2096	2690
TOTAL SYSTEM			68			7171	7318	6870	7011	96	622	9034	9656	9446	10170	8973	9719	276(I)	9204	9918	8919	9633	285(L)	8716	9452	8433	9169

(A) O-OIL, P-PULVERIZED COAL, G-NATURAL GAS, N-NUCLEAR
(B) MAXIMUM CAPABILITY OBTAINED WITH EITHER NATURAL GAS OR OIL
(C) COLD STAND BY UNITS NOT INCLUDED IN TOTAL
(D) OIL FIRED SUPERHEATERS
(E) AT 5% OVERPRESSURE
(F) PEAKLOAD DETAILS ON SHEET 1A
(G) GAS TURBINE DETAILS ON SHEET 1B
(H) WINTER RATING = 35 MW
(I) WINTER RATING = 291 MW
(J) WINTER RATING = 256 MW
(K) TOTAL = 24
(L) SUBTRACT 2 MW FOR SUSTAINED

REVISION Nº 1

CONVERTED HUDSON AVE TURBOGENERATOR Nº 2 TO 25 HZ EFFECTIVE JANUARY 26, 1973

REVISED TO

JAN. 31, 1973

Arthur Hampton
VICE PRESIDENT

TABLE VI.2-2

CONSOLIDATED EDISON SYSTEM

ELECTRIC GENERATING STATION CAPACITY

PEAKLOAD

(IA)

STATION	BOILERS: BOILER NUMBER OR ROW NUMBER	METHOD OF FIRING (A)	NUMBER OF BOILERS	STEAMING RATE PER BOILER MLBS / HR: MAXIMUM	STEAMING RATE PER BOILER MLBS / HR: SUSTAINED	EQUIVALENT ELECTRIC CAPACITY PER BOILER MW: MAXIMUM SUMMER	MAXIMUM WINTER	SUSTAINED SUMMER	SUSTAINED WINTER	TURBO — GENERATORS: UNIT NUMBER	NAME PLATE RATING MW: 25 CYCLE	60 CYCLE	TOTAL	OPERATING CAPACITY MW: MAXIMUM SUMMER	MAXIMUM WINTER	SUSTAINED SUMMER	SUSTAINED WINTER	FREQUENCY CHANGER RATING MW	TOTAL STATION RATING — MW: MAXIMUM CAPACITY MW: GROSS SUMMER	GROSS WINTER	NET SUMMER	NET WINTER	HOUSE TRANSFORMER MW	SUSTAINED CAPACITY MW: GROSS SUMMER	GROSS WINTER	NET SUMMER	NET WINTER
EAST RIVER L.P.	1 TO 6	O	6	175	150	11.7	11.7	11.7	11.7	1	60		60	53	55	53	55										
										4		175	175	165	169	165	169										
										5		8	8	5	5	5	5										
TOTAL			6			70	70	70	70	3	60	183	243	223	229	223	229	25 (D)	70	70	68	68	2	70	70	68	68
HELL GATE	1R	O-G	2	900	900	81	83	81	83	1		65	65	48	48	48	48										
	31,42,72	CSB-O	3	110	110	CSB	CSB	CSB	CSB	2	35		35	36	38	33	35										
	32	CSB-O	1	180	180	CSB	CSB	CSB	CSB	3	35		35	36	38	33	35										
	33,41,81	(C)	3	220	220	CSB	CSB	CSB	CSB	9		160	160	115	120	115	120										
	43,71,73	CSB-O	3	125	125	CSB	CSB	CSB	CSB																		
	82,83	O-G	2	220	220	18	19	18	19																		
TOTAL (F)			4			198	204	198	204	4	70	225	295	235	244	229	238	30 (D)	198	204	192	198	6	198	204	192	198
HUDSON AVENUE	3R	O	3	150	150	6	6	6	6	2	50 (I)		50	20	20	16	18										
	52	O	1	180	180	16	16.5	16	16.5	3	50 (I)		50	20	20	16	18										
	62	O	1	180	180	15	15.5	15	15.5	5		110	110	87	90	87	90										
	(G)	O	6	315	315	29	30	29	30	6		110	110	80	82	80	82										
	81	O	1	337	317	29	30	28	29	7		160	160	150	160	150	160										
	(H)	O	7	480	460	43.5	46	42	44	8		160	160	150	160	150	160										
	100	O	1	1400	1370	15.1	155	148	152	10		60	60	48	48	47	47										
TOTAL			20			708	737	693	719	7	100	600	700	555	580	546	575	30	555	580	515	540	40	546	575	506	535
WATERSIDE	41-42	O-G	2	440	440	39.5	40.5	39.5	40.5	4		53	53	34	34	34	34										
	51-52	O-G	2	405	405	36	37	36	37	5		53	53	31	31	31	31										
	61-62	O-G	2	655	655	65.5	66.5	65.5	66.5	6		65	65	58	58	58	58										
	71-72	G	2	680	680	62.5	70	62.5	70	7		65	65	60	66	60	66										
	80	O	1	1080	1080	105	108	105	108	8		50	50	46	46	46	46										
	90	O	1	940	940	70	70	70	70	9		50	50	32	32	32	32										
										10-13 (B)	35		140	101	107	101	107										
										14-15		60	120	120	130	120	130										
TOTAL			10			582	606	582	606	12	140	456	596	482	504	482	504	80	482	504	454	476	28	482	504	454	476
59 TH. STREET	110	O	1	640	640	52	55	52	55	7	35		35	22	24	22	24										
	111 - 113	O	3	280	280	20	21	20	21	8	35		35	26	28	26	28										
	114 - 115	O	2	475	475	10	10	10	10	13	60		60	52	55	52	55										
										14	22		22	19	19	19	19										
										15	35		35	20	20	20	20										
TOTAL			6			132	138	132	138	5	187		187	139	146	139	146	35	132	138	123	129	9	132	138	123	129
74 TH. STREET	120 TO 122	O	3	520	450	53	53	46	46	3	30		30	26	26	26	26										
										9-10		60	120	142	142	142	142										
										11	35		35	36	36	36	36										
TOTAL			3			159	159	138	138	4	65	120	185	204	204	204	204	46	159	159	147	147	12	138	138	126	126
TOTAL PEAK LOAD			49			1849	1914	1813	1875	35	622	1584	2206	1838	1907	1823	1896	246 (E)	1596	1655	1499	1558	97	1566	1629	1469	1532

(A) O - OIL, G - NATURAL GAS, CSB - COLD STAND BY
(B) DERATED 23 MW IN SUMMER AND 25 MW IN WINTER DUE TO 25 CYCLE SINGLE PHASE OPERATION
(C) 31, 41, COLD STAND BY - OIL, 81 COLD STAND BY - OIL - GAS
(D) ADD 5 MW FOR WINTER RATING.
(E) WINTER RATING = 256 MW
(F) COLD STAND BY UNITS NOT INCLUDED IN TOTALS
(G) BOILER NO'S 51, 53, 54, 61, 63, 64
(H) BOILER NO'S 71, 72, 73, 74, 82, 83, 84.
(I) CONVERTED FROM 60 CYCLE.

REVISION Nº 1

CONVERTED HUDSON AVE TURBOGENERATOR Nº 2 TO 25 HZ EFFECTIVE JANUARY 26, 1973

REVISED TO

JAN. 31, 1973

VICE PRESIDENT

TABLE VI.2-3

CONSOLIDATED EDISON SYSTEM
ELECTRIC GENERATING CAPACITY
GAS TURBINES

1B

STATION	UNIT NUMBER & FUEL (A)	NAMEPLATE RATING MW	FREQUENCY CHANGER RATING-MW	MAXIMUM CAPACITY SUMMER	MAXIMUM CAPACITY WINTER	SUSTAINED CAPACITY SUMMER	SUSTAINED CAPACITY WINTER
ARTHUR KILL	1 O	16		16	18	14	16
TOTAL	1	16		16	18	14	16
ASTORIA	1 G	15		15	18	15	18
	2-4 GK	154		468	552	408	504
	5-9 O	16		80	100	75	95
	10 O	24		25	31	22	28
	11 O	24		25	31	22	28
	12 O	24		25	31	22	28
	13 O	24		25	31	22	28
TOTAL	13	653		663	794	586	729
GOWANUS	1 O	155		152	200	144	192
	2 O	155		152	200	144	192
	3 O	155		152	200	144	192
	4 O	155		152	200	144	192
TOTAL	4	620		608	800	576	768
HUDSON AVENUE	1 K	17		17	20	14	18
	2 K	19		17	20	14	18
	3-5 O	16		48	57	42	51
TOTAL	5	84		82	97	70	87
INDIAN POINT	1 O	17		19	25	17	21
	2 (B) O	24		25	31	22	28
	3 (B) O	16		16	20	15	18
TOTAL	3	57		60	76	54	67
KENT AVENUE	1-2 K	14		22	28	22	28
TOTAL	2	28	30 (C)	22	28	22	28
NARROWS	1-2 KO	174		352	448	320	416
TOTAL	2	348		352	448	320	416
RAVENSWOOD	1 G	15		15	18	14	16
	2 GK	150		124	159	124	159
	3 GK	150		126	161	126	161
	4 GO	16		16	18	14	16
	5 GO	16		16	19	14	17
	6-7 GO	16		34	40	30	38
	8-11 GK	19		76	92	64	84
TOTAL	11	455		407	507	387	493
WATERSIDE	1 K	14		11	14	11	14
TOTAL	1	14		11	14	11	14
59 TH. ST.	1-2 K	17		34	40	28	36
TOTAL	2	34		34	40	28	36
74 TH. ST.	1-2 K	19		34	40	28	36
TOTAL	2	38		34	40	28	36
TOTAL	46	2347	30 (C)	2289	2862	2096	2690

(A) O - # 2 OIL, G - NATURAL GAS, K - KEROSENE
(B) - AT BUCHANAN
(C) WINTER RATING = 35

REVISION NO. 13

TRANSFERRED KENT AVE. FREQUENCY CHANGER FROM CONVENTIONAL TO GAS TURBINE SHEET UPON RETIREMENT OF CONVENTIONAL STATION.

REVISED TO

JAN. 1, 1973

Arthur Hanpney
VICE PRESIDENT

TABLE VI.2-4

NAME PLATE RATINGS AND SERVICE DATES OF ELECTRIC GENERATORS

STATION	UNIT NO.	NAME PLATE RATING-MW	SERVICE DATE
ASTORIA	1	180	11-10-53
	2	180	3-23-54
	3	335	9-29-58
	4	380	3-27-61
	5	380	5-22-62
	1 GT	15	7-17-67
	2 GT	154	6- 9-70
	3 GT	154	6-11-70
	4 GT	154	7-13-70
	5 GT	16	6-30-70
	6 GT	16	6-30-70
	7 GT	16	6-30-70
	8 GT	16	6-30-70
	9 GT	16	8- 6-70
	10 GT	24	1- 4-71
	11 GT	24	2- 1-71
	12 GT	24	5-14-71
	13 GT	24	5-12-71
RAVENSWOOD	1	363	2-21-63
	2	363	5- 6-63
	3	1000	6-15-65
	1 GT	15	7-24-67
	2 GT	150	12-31-70
	3 GT	150	8- 7-70
	4 GT	16	9-19-70
	5 GT	16	8-25-70
	6 GT	16	8-29-70
	7 GT	16	8-29-70
	8 GT	19	7-21-70
	9 GT	19	7-21-70
	10 GT	19	8-10-70
	11 GT	19	8-11-70
ARTHUR KILL	2	335	8-31-59
	3	491	6- 5-69
	1 GT	16	6-30-70
WATERSIDE	1 (E) (R)	40	12- 2-35
	4	53	9-10-37
	5	53	6-29-38
	6	65	7-30-41
	7	65	9-18-41
	8	50	6- 2-49
	9	50	10-17-49
	10	35	9-25-24
	11	35	10-29-19
	12	35	10-23-24
	13	35	12-16-19
	14	60	11- 9-48
	15	60	3- 7-49
	1 GT	14	10- 9-68
EAST RIVER	1	60	2-21-27
	2 (A) (R)	58	7- 2-62
	4 (B)	175	10-29-52
	5	137	9-20-51
	6	137	11-28-51
	7	180	6-24-55
	'S'	7.5	12-16-47
HELL GATE	1	65	2-23-46
	2	35	11-12-21
	3	35	12-11-21
	4 (R)	40	2-23-22
	8 (R)	160	12-27-28
	9	160	4-11-29

STATION	UNIT NO.	NAME PLATE RATING-MW	SERVICE DATE
SHERMAN CREEK (R)	5 (R)	22	2-24-21
	6 (R)	22	12-14-19
	7 (C) (R)	30	9-22-[illegible]
	8 (D) (R)	30	10-[illegible]
	9 (R)	50	4-[illegible]
	10 (R)	50	10-20-47
HUDSON AVENUE	1 (R)	50	5-12-24
	2	50	6-[illegible]
	3	50	10-22-24
	5	110	9- 1-29
	6	110	10-[illegible]
	7	160	1- 7-32
	8	160	5- 4-32
	10	60	8-24-51
	1 GT	17	7-27-69
	2 GT	19	7-27-68
	3 GT	16	7- 4-70
	4 GT	16	7- 4-70
	5 GT	16	7- 4-70
74TH STREET	3	30	7-30-15
	4 (R)	60	4-11-18
	9	60	11-20-59
	10	60	5- 6-56
	11	35	4-26-62
	1 GT	19	10-23-68
	2 GT	19	10-23-68
59TH STREET	7	35	6-17-18
	8	35	1-28-18
	13	60	3- 4-53
	14	22	5-23-63
	15	35	8- 1-68
	1 GT	17	6-12-69
	2 GT	17	2- 6-69
KENT AVENUE	10 (R)	35	10-21-20
	11 (R)	35	2-28-21
	12 (R)	19	6- 7-38
	13 (R)	19	7-20-38
	1	14	7- 8-69
	2	14	10-10-68
INDIAN POINT	1	275	9-30-62
	1 GT	17	7-17-69
BUCHANAN	3 GT	16	12- 2-70
	2	24	7-14-71
GOWANUS	1 GT	155	6-11-71
	2 GT	155	6-21-71
	3 GT	155	7-12-71
	4 GT	155	7-22-71

(A) REBUILT FOR 60 CYCLE OPERATION, DATE OF ORIGINAL INSTALLATION 11-19-26
(B) " " " " " " " " 10-10-15
(C) " " " " " " " " 8-17-15
(D) " " " " " " " " 7-29-15
(E) " " " " " " " " 10- 5-14
GT - GAS TURBINE

(R) = RETIRED

Question VI.3

A generation and capacity forecast for the years 1972 through 1981 should be supplied by completing the following table:

	Addition (or retirement)[a]			Total	Installed generation reserve	
Year	Net Unit load (MW)	Date	Unit Net capacity[b] (MW)	generating capacity (MW)	Megawatts	Percent	Percent without IP-3

[a]Include firm power purchases.

[b]Based on summer capability.

ANSWER:

Con Edison's submission to the New York Power Pool for inclusion in the March 1973 update of the Federal Power Commission Docket R-362 is included as Tables VI.3-1 through VI.3-4. Table VI.3-1 lists Con Edison's installed generating capacity by station as of March 1, 1973 for both summer and winter. Tables VI.3-2 and VI.3-3 list new unit additions, scheduled service dates, and summer and winter capacity of each new unit through 1982. Table VI.3-4 lists retirements and the decrease in system capacity caused by them through 1982. Table VI.3-5 lists proposed firm purchases through 1981. Table VI.3-6 lists the total system capacity and the reserves with and without Indian Point No. 3 for each year through 1981.

Area: Con Edison
Date: March 1973

TABLE VI.3-1

INDIVIDUAL GENERATING STATION CAPABILITY SUMMARY
MARCH 1, 1973

Company	Station	Type #	Fuel *	Capability - Mw Summer	Capability - Mw Winter
Consolidated Edison	Thermal				
	Arthur Kill	T	MF	806	831
	Astoria	T	MF	1458	1488
	Bowline Point (1)	T	O	400	400
	East River	T	MF	500	512
	Hell Gate	T	MF	192	198
	Hudson Avenue	T	O	515	540
	Ravenswood	T	MF	1778	1788
	Waterside	T	MF	454	476
	59th Street	T	O	123	129
	74th Street	T	O	147	147
	Total Thermal			6373	6509
	Nuclear				
	Indian Point	N	-	257	262
	Gas Turbines				
	Arthur Kill	G	O	16	18
	Astoria	G	MF	663	794
	Gowanus Bay	G	O	608	800
	Kent Avenue	G	O	22	28
	Narrows	G	O	352	448
	Ravenswood	G	MF	407	507
	Waterside	G	O	11	14
	74th Street	G	O	34	40
	Hudson Avenue	G	O	82	97
	Indian Point (includes Buchanan)	G	O	60	76
	59th Street	G	O	34	40
	Total Gas Turbines			2289	2862
	Total Capability, all Types (2)			8919	9633

\# Thermal (Conventional) - T
Thermal (Gas Turbine) - G
Thermal (Diesel) - D
Thermal (Nuclear) - N
Hydro (Conventional) - H
Hydor (Pumped Storage) - PS

* Fuels for Conventional, Gas Turbines and Diesels.
Coal - C
Oil - O
Gas - G
Multiple Fuels - MF

Note - Stations of less than 25 Mw capability are grouped by type under Miscellaneous.

(1) Bowline Point 1 is a 600 MW Unit. Orange & Rockland has a 1/3 share and Con Edison a 2/3 share.

(2) A total of 123 MW summer rating and 133 MW winter rating is on cold standby and not included in capacity. All this capacity is located at the Hell Gate Station and will be retired in December of 1973.

AREA: Con Edison
DATE: March 1973

TABLE VI.3-2

SCHEDULED AND PROPOSED CHANGES
NEW GENERATING UNITS AND UPRATING OF CAPACITY

Company	Station & Unit	Type #	Fuel *	Status Authorized(A) Planned (P)	Manufac-turer	Expected Net Capability-Mw Summer	Expected Net Capability-Mw Winter	Current Scheduled or Proposed Date of Service
Joint Unit	Roseton No. 1 (Con Ed Share)	T	O	A	G.E.	240	240	Jun 73
Con Edison	Indian Pt. No. 2	N	-	A	West	370	370	Jul 73
Joint Unit	Roseton No. 2 (Con Ed Share)	T	O	A	G.E.	240	240	Sept 73
Con Edison	Indian Pt. No. 2 Uprating	N	-	A	-	400	400	Sept 73
Con Edison	Indian Pt. No. 2 Uprating	N	-	A	-	103	103	Nov 73
Joint Unit	Bowline Pt. No. 2 (Con Ed Share)	T	O	A	G.E.	400	400	May 74
Con Edison	Indian Pt. No. 3	N	-	A	West.	873	873	Nov 74
	Astoria No. 6	T	MF	A	West.	800	800	Spring 75
	Location Undecided	G	O	P	-	550	700	Spring 76
	Location Undecided	G	O	P	-	220	280	Spring 77

\# Thermal (Conventional) -T
Thermal (Gas Turbine) -G
Thermal (Diesel) -D
Thermal (Nuclear) -N
Hydro (Conventional) -H
Hydro (Pumped Storage) -PS
Undetermined -U

* Fuels for Conventional, Gas Turbines and Diesels
Coal -C
Oil -O
Gas -G
Multiple Fuels -MF

1/ Con Edison has deemed it prudent for planning purposes to assume that the initial rating of Indian Point No. 3 will be equal to the rating of Indian Point No. 2. The Indian Point No. 3 Operating License Request is still for 965 MW.

AREA: Con Edison
DATE: March 1973

TABLE VI.3-3

SCHEDULED AND PROPOSED CHANGES
NEW GENERATING UNITS AND UPRATING OF CAPACITY

Company	Station & Unit	Type #	Fuel *	Status Authorized(A) Planned (P)	Manufac-turer	Expected Net Capability-Mw Summer	Expected Net Capability-Mw Winter	Current Scheduled or Proposed Date of Service
Con Edison	Indian Pt. No. 2 Uprating	N	-	P	-	92	92	Spring 78
	Indian Pt. No. 3 Uprating	N	-	P	-	92	92	Spring 78
	Location Undecided	G	O	P	-	110	140	Spring 78
	Indian Pt. No. 2 Uprating	N	-	P	-	35	35	Spring 79
	Indian Pt. No. 3 Uprating	N	-	P	-	35	35	Spring 79
	Cornwall Units #1-4	PS	-	A	-	1000	1000	Spring 79
	Cornwall Units #5-8	PS	-	A	-	1000	1000	Fall 79
	Indian Pt. No. 2 Uprating	N	-	P	-	33	33	Spring 80
	Indian Pt. No. 3	N	-	P	-	33	33	Spring 80
	Location Undecided	G	-	P	-	110	140	Spring 81

\# Thermal (Conventional) -T
Thermal (Gas Turbine) -G
Thermal (Diesel) -D
Thermal (Nuclear) -N
Hydro (Conventional) -H
Hydro (Pumped Storage) -PS
Undetermined -U

* Fuels for Conventional, Gas Turbines and Diesels
Coal -C
Oil -O
Gas -G
Multiple Fuels -MF

AREA: Con Edison
DATE: March 1973

TABLE VI.3-4

SCHEDULED AND PROPOSED CHANGES
RETIREMENT OF GENERATING UNITS AND DERATING OF CAPACITY

Company	Station & Unit	Type #	Fuel *	Decrease in Capability-Mw Summer	Decrease in Capability-Mw Winter	Expected Date of change
Con Edison	Hell Gate Station	T	0	192 (1)	198	4/73
	East River T-1, 4, "S" and B-(1-6)	T	0	68 (1)	68	4/73
	59th Street T-7	T	-	14	15	12/73
	Hudson Avenue B-30R	T	0	0	0	4/74
	Hudson Avenue T-2, 3	T	-	34	34	4/75
	Hudson Avenue T-5, 6 & B-50R, 60R	T	0	158	160	9/75
	Waterside T-(10-13)	T	-	100	106	12/75
	59th Street T-8	T	-	25	27	12/76
	Hudson Ave T-7, 8 (and Part of 70R & 80R Boilers)	T	0	282	302	4/77
Joint Unit	Roseton (Transfer portion to Central Hudson)	-	-	120	120	9/77
Con Edison	Hudson Ave (remainder of 70R and 80R boilers)	T	0	0	0	4/78
Con Edison	74th Street T-3	T	-	0	0	4/78
Con Edison	Waterside T-(4-7) and B-40R, 50R, 60R, 70R	T	0	166	172	5/79
Joint Unit	Roseton (transfer portion to Central Hudson)		-	120	120	9/81
Con Edison	Waterside Station	T	0	187	198	4/82

(1) All of Hell Gate, except for boilers 82 and 83 which will be used for steam supply, and the low pressure units at East River will be on cold stand-by in April of 1973, and their capability removed from the system installed capacity. Hell Gate Station will be retired by April of 1974, and the East River L.P. Units will be retired by December of 1974. There will be no effect on system installed capacity when the retirements occur.

\# Thermal (Conventional) -T
Thermal (Gas Turbine) -G
Thermal (Diesel) -D
Thermal (Nuclear) -N
Hydro (Conventional) -H
Hydor (Pumped Storage) -PS
Undetermined -U

* Fuels for Conventional Gas Turbines and Diesels
Coal -C
Oil -O
Gas -G
Multiple Fuels -MF

TABLE VI.3-5

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

FIRM PURCHASES 1973 - 1981

SUMMER	SOURCE	NET CAPACITY (MW)
1973	Rochester (Ginna)	256
	PASNY (Pump Storage)	142
	Ornage & Rockland (Bowline 1)	62
	Maine Public Service	28
	Under Discussion	282
		770
1974	Rochester (Ginna)	190
	Orange & Rockland (Bowline 2)	184
	Maine Public Service	28
	PASNY (FitzPatrick)	325
		727
1975	Maine Public Service	38
	PASNY (FitzPatrick)	310
		348
1976	Maine Public Service	38
	PASNY (FitzPatrick)	240
		278
1977	PASNY (FitzPatrick)	235
	Hydro Quebec	760
		995
1978	PASNY (FitzPatrick)	225
	Hydro Quebec	760
		985
1979	PASNY (FitzPatrick)	215
	Hydro Quebec	760
		975
1980	PASNY (FitzPatrick)	205
	Hydro Quebec	760
		965
1981	PASNY (FitzPatrick)	195
	PASNY (Breakabeen)	500
	Hydro Quebec	760
		1455

February 1973

TABLE VI.3-6

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

RESERVES WITH AND WITHOUT INDIAN POINT NO. 3

YEAR	TOTAL SYSTEM CAPACITY	RESERVE WITH INDIAN POINT NO. 3		RESERVE W/O INDIAN POINT NO. 3	
		MW	%	MW	%
1973	10039	-	-	1339	15.4
1974	11125	-	-	1975	21.6
1975	12385	2835	29.7	1962	20.5
1976	12607	2657	26.7	1784	17.9
1977	13237	2837	27.3	1664	18.9
1978	13401	2551	23.5	1586	14.6
1979	14295	2995	26.5	1995	17.7
1980	15351	3601	30.6	2568	21.9
1981	15951	3751	30.7	2718	22.3

February 1973

Question VI.4

The attached table entitled "Values for Peak Demand Hour" should be completed.

ANSWER:

A completed table entitled "Values for Peak Demand Hour" is attached as Table VI.4-1. The capacity data shown on Table VI.4-1 is based on the response to Question VI.3. The "Applicant Predicted Demand" column has been left blank from 1961 to 1972, and this information has been provided in response to Question VI.15.

The "Applicant Predicted Demand" column has been completed for the years 1973 to 1980. It cannot be stated too emphatically, however, that the "Peak Load Demand" column, by itself, is inadequate for predicting future loads. For example, the Summer of 1967 was very cool, with no prolonged hot spells, and as a result of this factor the actual peak load was lower than that of the year before.

In attempting to forecast future peak loads, a trend of adjusted loads, stated on a common basis, must be employed. For this reason we have included the adjusted peak load of each year in Table VI.15-1. These data represent the summer season actual peak loads adjusted to a common weather basis which has a frequency of occurrence of approximately once in three years. These loads are also adjusted for the effects of voltage reduction and the special appeals that were made to our customers for conservation of energy on high load days, as discussed in the answer to Question VI.16. In the appended chart (Chart VI.4-2), both the adjusted historical peaks and their projection to the year 1980 are shown. In extending the adjusted historical data into the future, the 1971-1972 adjusted peaks were disregarded since they were still depressed due to an economic recession, which was a short term factor with no long term effect on the load forecast. In addition the projection starting in 1973 was slightly lowered in order to allow for the impact of the Save-A-Watt campaign. Beginning in 1971 Consolidated Edison embarked on its Save-A-Watt campaign in order to effect a general, on-going reduction of both peak load and energy consumption. Since it is anticipated that this campaign will impact upon our loads for many years to come, it has been included as a factor to lower our long term load projections.

TABLE VI.4-1

CON EDISON
(Applicant)

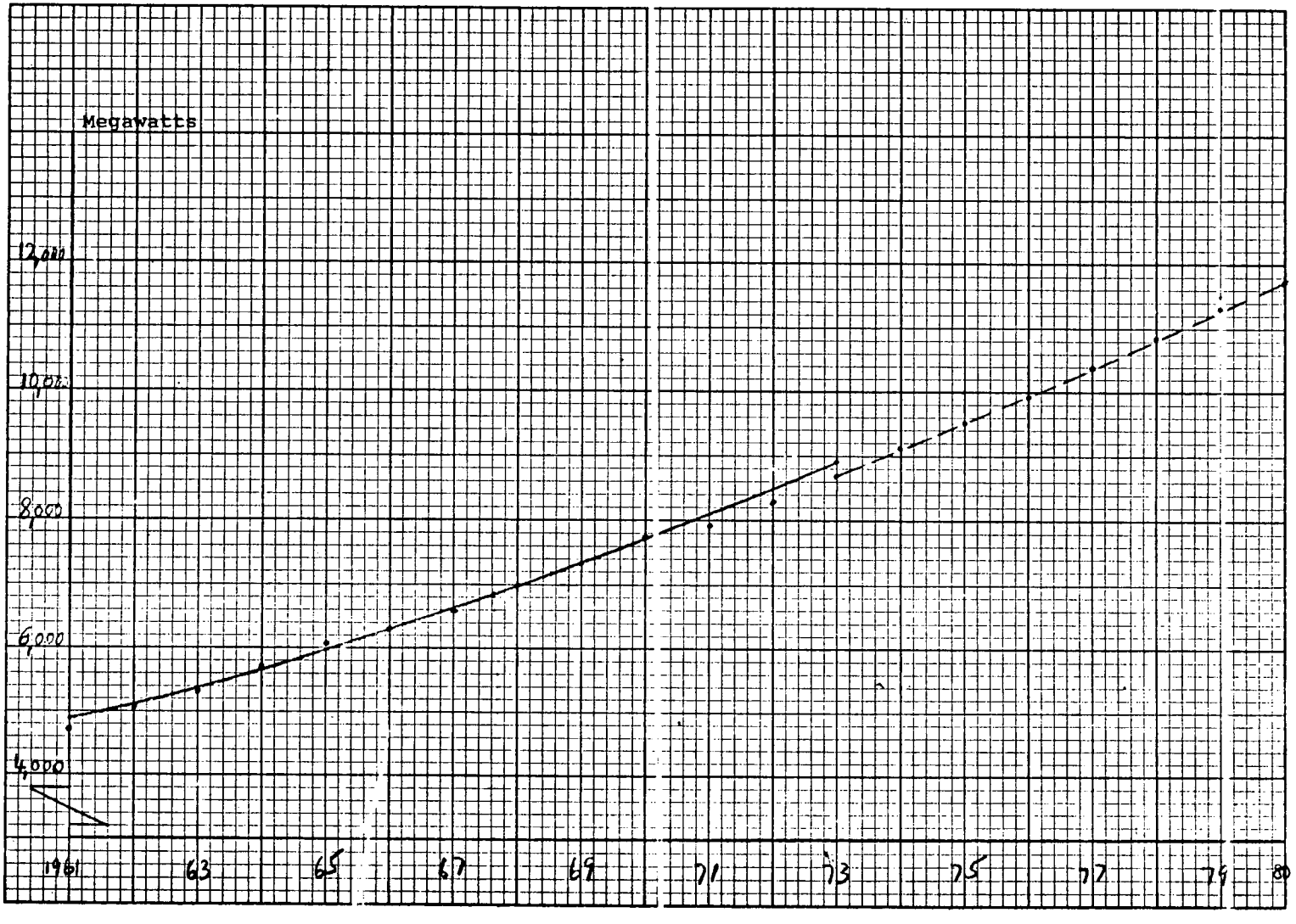
VALUES FOR PEAK DEMAND HOUR

YEAR	HYDRO CAPACITY	FOSSIL CAPACITY	GAS TURBINE CAPACITY	PUMPED STORAGE CAPACITY	NUCLEAR CAPACITY	NET PURCHASES	TOTAL SYSTEM CAPACITY	PEAK LOAD DEMAND	APPLICANT PREDICTED DEMAND	REMARKS
1961	0	5197	0	0	0	78	5275	4744		
1962	0	5637	0	0	0	260	5897	4852		
1963	0	6350	0	0	255	260	6865	5105		
1964	0	6289	0	0	255	260	6804	5505		
1965	0	7272	0	0	255	260	7787	5710		
1966	0	7222	0	0	255	250	7727	6154		
1967	0	7222	30	0	260	20	7532	6147		
1968	0	7207	30	0	260	523	8020	6960		
1969	0	7698	185	0	260	260	8403	7266		
1970	0	7723	974	0	260	520	9477	7041		
1971	0	6665	1603	0	260	800	9328	7719		
1972	0	6234	2332	0	260	778	9604	7872		
1973	0	6353	2289	0	627	770	10039	-	8700	
1974	0	6979	2289	0	1130	727	11125	-	9150	
1975	0	7745	2289	0	2003	348	12385	-	9550	
1976	0	7487	2839	0	2003	278	12607	-	9950	
1977	0	7180	3059	0	2003	995	13237	-	10400	
1978	0	7060	3169	0	2187	985	13401	-	10850	
1979	0	6894	3169	1000	2257	975	14295	-	11300	
1980	0	6894	3169	2000	2323	965	15351	-	11750	

CHART VI.4-2

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Adjusted Peak Load 1961 - 1972 and Projection 1973 - 1980



Question VI.5

A tabulation of consumption of electricity in the applicant's service area by user classification (residential, commercial and industrial, other) for 1960 and 1970 plus projections for 1975 and 1980 should be provided.

ANSWER:

A listing of the consumption of electricity by user classification for 1960 and 1970 with projections for 1975 and 1980 is attached as Table VI.5-1.

TABLE VI.5-1

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CONSUMPTION OF ELECTRICITY BY USER CLASSIFICATION

	Millions of Kilowatt Hours			
	1960	1970	1975	1980
Residential	4,216	7,931	9,852	12,575
Commercial & Industrial	11,343	19,358	23,291	29,091
Other (RR & Govmt.)	3,334	4,299	5,457	6,984
Total	18,893	31,588	38,600	48,650

NOTE:

Due to changes in service classifications over the period, the distribution between "Commercial and Industrial" and the other two classifications may not be strictly comparable.

February 1973

Question VI. 6

A map showing the applicant's generation and transmission facilities including interconnections with adjacent utilities should be supplied.

Answer:

Three maps showing Con Edison's generation and transmission facilities, including interconnections with adjacent utilities, for the Summers of 1973 through 1975 are attached as Figure VI. 6-1 through VI. 6-3.

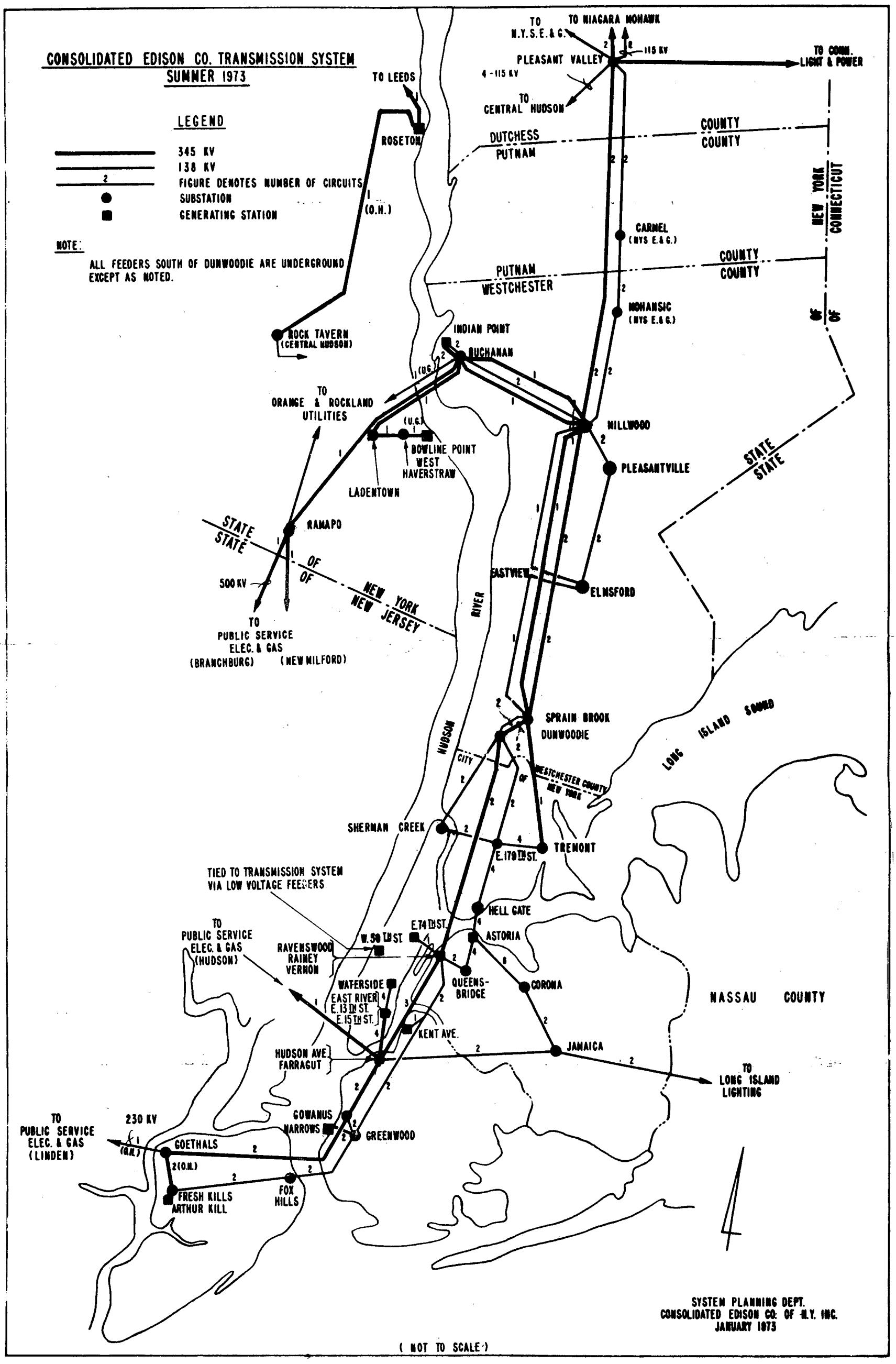


Figure VI. 6-1. Consolidated Edison Co. Transmission System Summer 1973

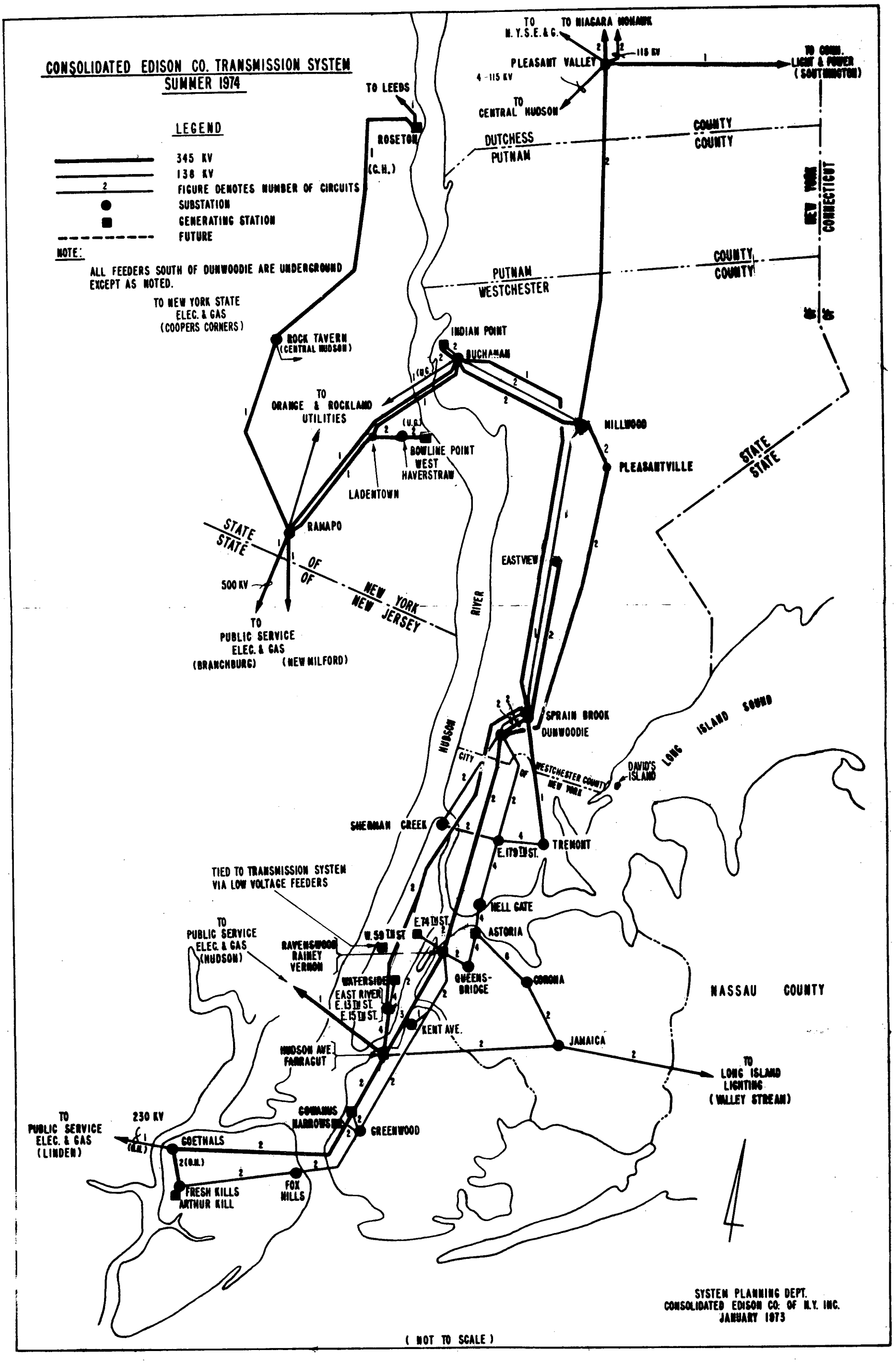


Figure VI.6-2. Consolidated Edison Co. Transmission System Summer 1974

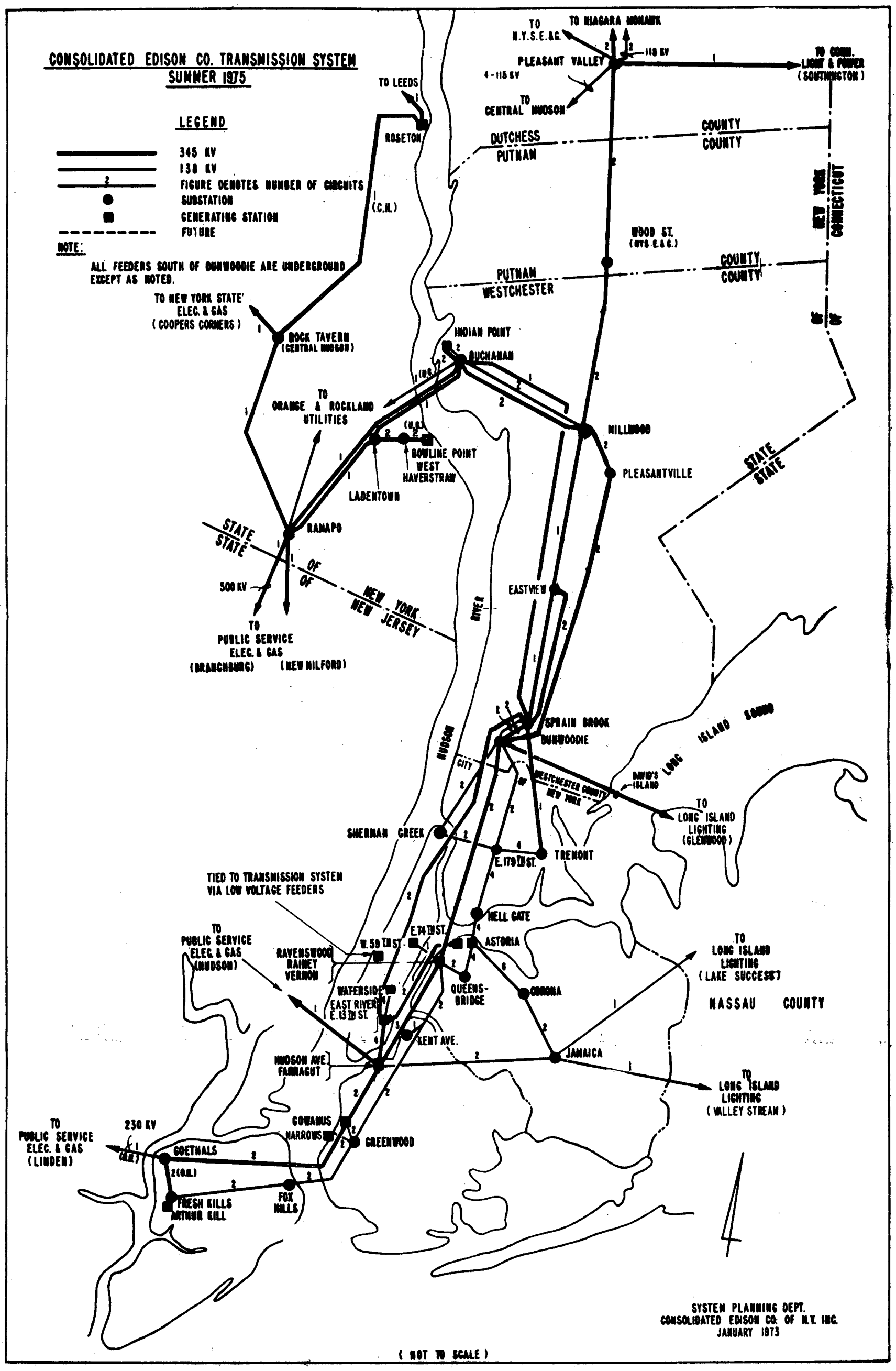


Figure VI.6-3. Consolidated Edison Co. Transmission System Summer 1975

Question VI. 7

Actual quantities of load shed on September 22, 1970 should be provided.

Answer:

On September 22, 1970 from 3:53 P.M. to 4:40 P.M. load shedding took place in the Pleasantville area, affecting 6,980 consumers, and reducing the system load by 13 MW. On the same day from 3:53 P.M. till 6:47 P.M. load shedding took place in the Fresh Kills area, affecting 59,953 consumers, and reducing the system load by 44 MW. The total load reduction from3:53 P.M. to 4:40 P.M. was 57 MW. This is the only occasion where it was necessary to deliberately disconnect load on the Con Edison system due to a shortage of capacity to supply the total system load. An 8% voltage reduction, the maximum voltage reduction possible, was in effect at the time the load disconnections took place.

Question VI.8

What will be the impact of Indian Point Units Nos. 2 and 3 on Con Edison's spinning reserve obligations to the New York Power Pool.

Answer:

There will be no change in Con Edison's spinning reserve obligations to the New York Power Pool (NYPP) because of Indian Point Units Nos. 2 and 3. Spinning reserve is defined in NYPP Operating Policy No. 2-3 as "that portion of unused generating capability which is synchronized, which will respond immediately and which is fully available within five minutes." Certain hydro and quick-start combustion units which can be synchronized and loaded within five minutes can be included but not to exceed one-third of the required Pool spinning reserve. Scheduled Reserve is defined in NYPP Operating Policy No. 2-3 as "that additional portion of unused generating capability which can and will be made fully available as promptly as possible, but in no more than thirty minutes." The total of Spinning Reserve obligation and Scheduled Reserve obligation is The Operating Reserve obligation. Both components of the Operating Reserve obligation are functions of the maximum company peak load in the prior two capability periods (previous full year) in ratio to the sum of the maximum peak loads of all the Members of the Pool and the capability of the Company's largest unit in ratio to the sum of the capabilities of the largest units of all of the Members of the Pool. Certain restrictions are also applied so that the Operating Reserve of any individual Pool Member does not exceed the capability of that member's largest unit nor the installed reserve obligation. Indian Point Units Nos. 2 and 3 will affect Con Edison's Scheduled Reserve obligation. Calculations were performed for the Summer of 1974 (the first summer load period that Indian Point No. 2 will be available at full power - 873 MW) and for the Summer of 1975 (Indian Point No. 3 - based on capacity requested for operating license: 965 MW).

Con Edison's Operating Reserve obligations for the Summer of 1974:

	Without Indian Point No. 2	With Indian Point No. 2
Spinning Reserve (MW)	350	350
Scheduled Reserve (MW)	316	336
Total Operating Reserve (MW)	666	686

Con Edison's Operating Reserve obligations for the Summer of 1975:

	Without Indian Point No. 3	With Indian Point No. 3
Spinning Reserve (MW)	337	337
Scheduled Reserve (MW)	317	357
Total Operating Reserve (MW)	654	694

For the purposes of these calculations forecast loads were used for all the Members of the NYPP. NYPP Operating Policy No. 2-3 requires that actual recorded peak loads be used since it is intended to apply to current day-to-day operating calculations. Should Con Edison's actual peak loads in the Summers of 1973 and 1974 be less than the peak load forecast the Operating Reserve obligations would be reduced.

Question VI. 9

Major supplies of oil to Con Edison and major contract quantities of oil per year should be identified.

Answer:

Con Edison's major suppliers of residual oil for 1973 are as follows:

Oil Supplier	Millions of barrells per year
Exxon	10
Hess	11
Texaco	5
Nepco	23

Question VI. 10

What percentage of this oil comes initially from foreign sources?

Answer:

All of the residual oil quantities listed in response to Question 9 initially come from foreign sources.

Question VI. 11

In general terms, what is the oil availability to Con Edison for the decade of the 1970's and, if possible, the decade of the 1980's?

Answer:

Con Edison's current residual oil contracts expire in 1975. While it is not possible to project oil availability, with 100% certainty, beyond that point, the Company anticipates that the present contracts will be renewed or that other qualified suppliers will be added at the expiration of the present contracts.

Question VI. 12

What is a typical current supply of oil on hand in days of generation supply? Also include days of generation supply from oil in transit.

Answer:

For Con Edison, a typical current supply of residual oil on hand and in transit would be equivalent to about twenty-five days of generation supply.

Question VI. 13

Major transmission projects currently authorized with a description of delays, permits, or public hearings that contributed to the delay of the project should be listed.

Answer:

The following list reviews transmission projects currently underway or just completed including major delays affecting their service dates:

1. Public Service Electric & Gas Company - Interconnections

   a. Farragut Tie to Hudson, New Jersey - Originally scheduled for completion on May 1, 1972 based on a construction starting date of Spring 1971. To avoid expiration of local permits starting date was advanced to November or 1970. However, because of a construction delay encountered with respect to a phase angle regulator, project was completed in December of 1972.

   b. Ramapo Tie to New Milford, New Jersey - Originally scheduled for completion on May 1, 1972 based on a construction starting date of Spring, 1971. Applied to P.S.C. for Certificate of Environmental Compatibility and Public Need in April 1971. P.S.C. granted Certificate February 8, 1972 and Approved Environmental Management and Construction Plan on March 7, 1972. Construction accelerated from original planned 12 months to 7-8 months. Con Edison's portion of the line completed early in 1973. Because of difficulties encountered by Public Service Electric and Gas Company in obtaining local permits for construction of a necessary substation, project completion delayed at least until late summer, 1973. P.S.E. & G has filed a petition with the New Jersey Public Utility Commission requesting approval to proceed and are awaiting a decision.

   c. PJM Interconnection - Originally scheduled for completion in mid-1968. Delays were encountered in obtaining local permits and necessary Right-of-Way Agreements were reached in mid-1971 and construction completed in March, 1972.

2. Southern Tier Interconnection

North-South Section - Ramapo to Rock Tavern

East-West Section - Rock Tavern to Coopers Corners

Original scheduled completion date was 1-1-71. Because of Right-of-Way problems, the Company applied in Summer of 1970 to the N.Y.S. Public Service Commission for a Certificate of Environmental Compatibility and Public Need. The Company received the Certificate for the North-South Section on January 25, 1972. The East-West Section were remanded for additional hearings. The P.S.C. Certificate was appealed by intervenors in N.Y.S. State Supreme Court and Court of Appeals. On December 6, 1972, the N.Y.S. Court of Appeals affirmed the ruling of the State Supreme Court, Appellate Division, which upheld the P.S.C. Certification. Construction of the North-South Section is now scheduled for completion by the Summer of 1974.

3. Rebuild Aqueduct Right-of-Way

The rebuilding of the 138 KV double circuit overhead line for 345 KV operation was scheduled to take 2 years with completion scheduled for Spring of 1969. However, agreements with New York City and subsequent approval by the City Board of Estimate were not completed until the Summer of 1972. Construction problems in removing the existing lines further delayed starting date until the fall of 1972. In installing related underground feeders between Eastview and Elmsford delays were experienced in obtaining local permits. P.S.C. Certificate of Environmental Compatibility and Public Need was obtained and construction completed late in 1972 instead of April 1972.

Construction schedule for overhead line is being accelerated with completion expected in Summer of 1974.

Question VI. 14

A general description of Con Edison's ability to import major amounts of bulk power from 1973 until after Indian Point Unit No. 3 is in service should be presented.

Answer:

The northern substation terminus of Con Edison's overhead electric transmission system is at Pleasant Valley in Dutchess County. This substation is the interconnection between the Company's system and the Niagara Mohawk Power Corporation via two 345 KV ties and two 115 KV ties. It is also the point of interconnection with Central Hudson via four 115 KV ties, with New York State Electric and Gas via a 115 KV tie and with the New England Power Exchange via a single circuit 345 KV tie running to Connecticut Light and Power Company's Southington substation.

From Pleasant Valley there are two double circuit tower lines running south to the Millwood substation. One of these towers is at 345 KV and one is at 138 KV. During Summer 1974 the 138 KV tower line will be removed from service to be reconstructed for 345 KV operation.

To the west the Company is interconnected with the Pennsylvania-New Jersey-Maryland System (PJM) via a 500 KV tie from Public Service Electric and Gas Company's Branchburg substation to our Ramapo substation in Rockland County. The Ramapo substation is also interconnected with Orange and Rockland Utilities via a 138 KV tie. This station will also be the terminus for the Southern Tier transmission line which is scheduled to be in service Summer 1974 and for the New Milford tie with Public Service Electric and Gas Company of New Jersey which is scheduled to be in service Summer 1973.

From the Ramapo substation, there are two 345 KV lines running northeast to the Buchanan substation. During Summer 1974, one of these lines will be connected to Buchanan via the Ladentown substation. Generators 1 and 2 at Bowline Point will be connected to Ladentown. Buchanan is also the substation to which Units 1 and 2 at Indian Point are connected. At Buchanan, there is also a normally opened 138 KV cable tie to Orange and Rockland's Lovett Generating Station.

From Buchanan, there are three 345 KV circuits and two 138 KV circuits which run to the area of the Millwood substation. From the Millwood substation, there are two double circuit 345 Kv lines which run south to the Sprain Brook and Dunwoodie substations in Yonkers. In 1973 these two tower lines will be the 1956 and the 1961 lines. By Summer 1974 a third double circuit tower line will be placed in service between Millwood and Sprain Brook/Dunwoodie. At that time, the 1961 line is scheduled to be removed from service for reconductoring. It will be returned to service in Spring 1976. The Sprain Brook/Dunwoodie substations are the southern termini of the Company's overhead system and the point at which the Company's underground system begins.

The underground transmission system is composed of 345 KV and 138 KV cables which connect various substations within the City and by which power is moved from sources of supply, either purchases or generation, to the main area substations which supply local distribution facilities.

Con Edison's system also interconnects with Public Service Electric and Gas Company's Linden substation via a 230 KV overhead transmission line running to the Company's Goethals substation on Staten Island and via an underground 345 KV transmission line between the Company's Farragut sybstation in Brooklyn and Public Service Electric and Gas Company's Hudson generating station in Jersey City, New Jersey.

Finally, there are two underground 138 KV transmission lines which connect Long Island Lighting Company's Valley Stream substation in Nassau County with Con Edison's Jamaica substation in Queens. An application for certification of a 345 KV transmission line to connect the Company's Dunwoodie substation in Yonkers with LILCO's Glenwood substation in Nassau County and a 138 KV transmission line between Jamaica and Lake Success is now pending before the N.Y.S. Public Service Commission. The service date of these facilities is the summer of 1975.

During Summer 1973 the Company should have an import capability of approximately 1,850 MW above our share of one Roseton Unit and the Bowline Point Unit.

If Indian Point No. 3 is not in service, the Company should have an import capability above our shares of the Roseton and Bowline Point units of 2150 MW in the Summer of 1974 and 2200 MW in the Summer of 1975.

If Indian Point No. 3 is in service in the Summer of 1975 the Company should have an import capability of 1500 MW.

All planned purchases must be subtracted from the import capability figures presented above.

Question VI. 15

What are the predicted peak load demands for the year 1961 through 1972?

Answer:

Peak loads for the year 1961 through 1972 as estimated five years and one year in advance are shown on the attached Table VI. 15-1. This table also includes a column for "Adjusted Peak Loads" as discussed in the answer to Question VI. 4 and VI. 16. If the "Estimated Peak Loads" were compared to the "Adjusted Peak Loads," the estimates would be either accurate or too low, except in 1971 and 1972 when the combined effect of recession and Save-A-Watt acted to depress the load.

TABLE VI. 15-1

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
PEAK LOAD 1961-1972
(MEGAWATTS)

Year	Actual Peak Load	Adjusted Peak Load	Estimated Peak Load	
			Five Years In Advance	One Year In Advance
m	(1)	(2)	(3)	(4)
1961	4 744	4 725	4 050	4 675
1962	4 852	5 025	4 275	5 025
1963	5 105	5 325	4 475	5 350
1964	5 505	5 750	5 575	5 700
1965	5 710	6 050	5 825	6 050
1966	6 154	6 280	6 175	6 275
1967	6 147	6 575	6 550	6 550
1968	6 960	7 000	6 850	6 850
1969	7 266	7 350	7 150	7 350
1970	7 041	7 750	7 450	7 725
1971	7 719	7 950	7 750	8 150
1972	7 872	8 275	8 050	8 400

NOTE: The adjusted loads are derived from actual loads by adjusting observed readings to assumed standard peak weather conditions-a clear day with maximum average wet-dry bulb temperature of 86° F. for three consecutive days at the warmest part of the air-conditioning season, declining to values of comparable frequencies (once in three years) at the beginning and end of the season.

Question VI. 16

During which years were the actual peak loads reduced by employing voltage reductions?

Answer:

The actual annual peak loads reported in Table VI. 15-1 include only two (2) occurrences of voltage reduction at the time of the actual system peak load - 1969, when the load would have been 90 MW higher and 1971, when the voltage reduction in effect amounted to 24 MW during the peak hour.

However, in attempting to forecast future peak loads, a trend of adjusted loads, stated on a common basis, must be employed. For this reason we have included the adjusted peak load of each year in Table VI. 15-1. These data represent the summer season actual peak loads adjusted to a common weather basis which has a frequency of occurrence of approximately once in three years. They are also adjusted for the effects of voltage reduction and, in 1970, for the special appeals that were made to our customers for conservation of energy on high load days. (In 1970, for example, an adjustment of 300 MW was made for 5% voltage reduction and one of 400 MW for special appeals to customers).

Beginning in 1971 Consolidated Edison embarked on its Save-A-Watt campaign in order to effect a general, on-going reduction of both peak load and energy consumption. The effects of this campaign have not been included in the adjusted loads, since it is anticipated that these effects will be incorporated in our system loads for many years to come, a fact that has been reflected in our load projections.

It cannot be stated too emphatically, however, that the actual data, by themselves, are inadequate for predicting future loads. For example, the Summer of 1967 was very cool, with no prolonged hot spells, and only as a result of this factor was the actual peak load lower than that of the year before.

Question VI. 17

How much emergency power has Con Edison supplied to members of the New York Power Pool in recent years? Please list by year and note whether transfers occurred during summer or winter?

Answer:

Con Edison emergency sales to other Members of tne New York Power Pool were as follows:

	Megawatt-Hours		
YEAR	SUMMER	WINTER	TOTAL
1970	7,986	22,221	30,207
1971	4,105	5,703	9,808
1972	6,922	497	7,419

Question VI. 18 3

If available, any seasonal diversity exchange agreements with other utilities should be listed.

Answer:

Con Edison has had no seasonal diversity exchange agreements with other utilities in recent years and there are currently no plans to do so.