TVA's

POWER PLANT MAINTENANCE PROGRAM

Philosophy and Experience

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INTRODUCTION

A strong preventive maintenance program during 40 years of hydroelectric plant operation and 20 years of steam-electric plant operation has uncovered most of the potential maintenance problems that might occur during the lifetime of generating equipment, with the result that facilities have operated all these years with a minimum of catastrophic damage. The TVA system generating capacity now in operation totals approximately 20,000 MW supplied by hydroelectric, fossil steam-electric, and new gas turbine units. Additional capacity of approximately 16,000 MW is under construction or approved for completion by 1978. Of this additional capacity, 11,000 MW will be nuclear steam-electric. A total of 57 steam units, 113 hydro units and 20 gas turbine units is now being maintained.

Most of the hydroelectric generating capacity was installed before 1952 with the oldest unit dating back to 1912. During the past 20 years, TVA has added 17,000 MW of capacity, most of which was fossil steam-electric units. This period of rapid growth began by the addition of 125-MW units in 1952 with size escalation up to 1150-MW units in the early 1970s. In most instances, the additional capacity put into service during this period represented the largest units the turbogenerator and steam-generator manufacturers were capable of designing and building; consequently, maintenance problems associated with prototype units were faced during the entire period.

MAINTENANCE ORGANIZATION

General

TVA performs most of the maintenance required by the generating plants with a minimum of outside contracting. An organization has been established to plan, supervise, and perform all aspects of preventive and emergency maintenance, inspection, and repair. This organization encompasses plant personnel; the central service shops in Muscle Shoals, Alabama; and the central office technical staff in Chattanooga, Tennessee.

Plants

Each plant has various shops and a complement of maintenance personnel for handling routine maintenance. The number of plant maintenance employees varies from approximately 170 at the larger 2000-MW steam plants to only 2 at some smaller hydro plants. During extended outages for heavy maintenance, additional employees are obtained from the local labor market and TVA's central service shops to supplement the plant employees.

Central Service Shops

The central service shops, now being expanded, are equipped to repair large mechanical and electrical equipment and to fabricate many parts. Installed equipment includes machine tools ranging in size up to a 20-ft vertical boring mill and a 110-in. lathe which will swing most of the turbine spindles. The electrical portion of the shops is equipped to untank and repair large transformers, rewind motors up to 5000 horsepower, and repair electrical bushings.

The service shops also serve as a source of experienced manpower for traveling crews to inspect and overhaul turbines and generators, utilizing special tool trailers dispatched for these inspections. The permanent complement of the service shops consists of approximately 120 mechanical and 50 electrical repairmen. During extremely heavy maintenance periods, these men serve as a nucleus of crews; and supplemental temporary help is obtained from the local labor markets.

Central Office Technical Staff

Each generating plant has a capable technical staff for most of its maintenance planning and supervision. However, a central office technical staff of approximately 50 employees with responsibility for planning, coordinating, and scheduling maintenance activities is used for major maintenance such as turbine overhauls and large steam-generator modifications. When these jobs are in progress, one or more of these technical employees, who gain experience from plant to plant, may be assigned to supervise a segment of the work at the site.

MAINTENANCE PRACTICE AND SCHEDULING

Scheduled Turbine Inspections

Generally, steam turbines are opened for inspection at the end of the first year's operation and every 35,000 operating hours thereafter (approximately every 5 years). These outages require 4 to 8 weeks, depending upon the size of the turbogenerator and maintenance requirements.

Scheduled Steam-Generator Inspections

Initially, the smaller pulverized-fuel steam generators were inspected each year; but, as they reached maturity and the margin of capacity for maintenance became more critical, the interval between inspections was lengthened to 18 months or 2 years. The inspection of large pulverized-fuel steam generators, 500 MW and above, and all cyclone-fired steam generators continues on a yearly basis.

Schedule Development

Planning and scheduling outages for maintenance require very close coordination with those responsible for other aspects of TVA's system operation. Designated technical staff members meet monthly with those responsible for the operation and loading of the transmission system to develop the long-range outage schedule, taking into consideration flood control, system-loading requirements, and scheduled and emergency maintenance.

Change in Maintenance Pattern with Interchange Agreement

From the early 1950s to the middle 1960s an ideal situation existed to accomplish maintenance because the peak load resulted from home heating during 3 winter months, allowing approximately 9 months of the year for scheduling maintenance outages. However, to better utilize available capacity, TVA entered into an interchange agreement with utilities in the Southwest for power that is now in the range of 2000 MW. TVA receives power during the winter for heating load, repaying it during the summer when the other utilities have a high air-conditioning load. A comparison of the effect of this interchange on maintenance scheduling can be seen by referring to Figs. 1 and 2 (capacity available for maintenance in 1965 and the steam plant outage schedule for that year) and to Figs. 3 and 4 (1971 comparison charts).

The time available for maintenance has been drastically reduced. Outages are now scheduled primarily from March through May and from October through November. The impact of this shorter maintenance period has increased the problems associated with obtaining replacement parts and qualified manpower and has increased maintenance costs. Normally, work on the larger, more efficient units is performed on an overtime basis because of the shortage of manpower and the economic advantage of reducing outage time.

Critical-Path Method

In an effort to better utilize the outage time and the scheduling of tools and manpower, a consultant was retained and a training seminar on the critical-path method of scheduling maintenance was held for plant supervisory personnel and central office maintenance specialists. Indoctrinating all those associated with maintenance in the same techniques enables the maintenance specialists and mechanics who move from plant to plant to be familiar with the methods and charts used. The critical-path method is very useful on major overhauls for detailed scheduling of manpower and shop requirements.

STEAM TURBOGENERATOR EXPERIENCE

Solid-Particle Erosion

Solid-particle erosion by oxides exfoliated from chrome-alloy steam-generator tubes is the largest single maintenance problem experienced on the 57 steam turbogenerators. Primarily, the solid-particle erosion has occurred in the reheat section of the turbines and, to a much lesser extent, in the high-pressure sections. The erosion was evidenced early in the life of the turbines as an eroding away of rotating blade tenon rivets which allowed the shrouds to come off. Pieces of shroud were lost in two turbines. Turbine repairs of re-riveting or welding a tenon on the blade had to be made approximately every 20,000 operating hours. Later, a modification was made in which the shroud was counter-bored so that the tenon could be recessed below the surface of the shroud to protect the tenon from erosion. This allowed the normal 35,000 hours between inspections and as long as 70,000 hours between repairs. Now, after approximately 100,000 hours, excessive general erosion of the vane section has made it necessary to replace selected blades.

Stationary-blade failures were experienced after approximately 140,000 operating hours on one of a series of turbines. Investigation showed that the solid-particle erosion had created a small notch at the base of the vane section, and this stress riser apparently caused the failure of the stationary blading. Other blades were found to have cracks propagating from this notch.

Blade Failures

Generally, turbine rotating-blade failures have been confined to the first-stage blading of the high-pressure turbine; and the problem was associated with resonant vibration of the blades from partial-arc steam admission. Of the 57 turbines that have gone into operation since 1950, 34 have had first-stage blades modified because of actual failure, or failure of similar blading. Corrections are being made on 5 other turbines on which the turbine manufacturer has warned of blade failure from experiences elsewhere. The second most susceptible area to blade failure has been the last or the next-to-the-last row of blading in the low-pressure turbines. Three turbines have experienced blade loss in the last row, and another series of turbines has experienced cracking in the next-to-the-last row, but no blades have broken off.

Turbine Spindle Replacements

Until recently, it had not been necessary to replace spindles except in one class of units. In this class of 14 turbines, 3 high-pressure and 8 intermediate-pressure spindles had to be retired early because of creep-rupture cracking. Recently, a high-pressure spindle was replaced when numerous sonic indications were found as a result of an ultrasonic-bore inspection. It is not known whether these flaws were originally present in the forging or whether they developed during operation since this was the first time an inspection of this type had been performed on this spindle. This turbine had 90,000 operating hours. Two other intermediate-pressure turbine spindles are scheduled for replacement as soon as delivery is made because of thermal cracking in the blade-groove walls. These also have approximately 90,000 operating hours.

Turbine-Casing and Steam-Chest Cracking

Within the last few years, TVA has experienced thermal cracking in several of the high-pressure steel-alloy castings such as turbine inner shells and valve casings. The cracks must be removed by grinding; and, where they are deep enough to endanger the integrity of the vessel, weld repair is used. Early attempts to weld with nickel-chrome alloy 600 proved unsuccessful because cracks would reappear at the heat-affected zone. Where welding is required, repairs are now generally made using a 550 F. preheat and a 0.5-percent chromium, 1-percent molybdenum filler-metal with a stress relief at 1300 F. for 8 to 10 hours. In one case, the control-valve steam chest of a 500-MW unit had cracked severely in several locations after 55,000 hours of service. Extensive grinding removed the internal flaws, and the chest was reinforced by pad-welding on the outside by depositing approximately 800 pounds of weld metal.

A permanent repair is not always effected by removing the cracks and reinforcing the outside by welding. In fact, the uneven surfaces from grinding may localize stresses, causing progressive cracking. This is the situation on two 700-MW units on which the steam chests are being replaced after 8 years' operation. TVA's experience, confirmed by discussions with turbine manufacturers, has created a very pessimistic outlook concerning this problem. Even with improved quality control, improved design, and conservative loading practices, some type of cracking is expected to occur in 20 percent of the installed high-temperature turbine inner casings and valve-chest castings within 5 years and in 70 percent within 20 years in the large high-pressure units.

Bolting Failures

High-temperature bolting failures, primarily in the turbine and turbine valves, are a continuing problem that must be watched carefully. Early bolting problems included the failure of embrittled cobalt-containing nozzle-block capscrews and valve and shell bolting. This was corrected by replacing the small bolting with chrome-vanadium material and by setting up a program to check the hardness of the larger shell bolting during turbine inspections and to anneal it when the hardness becomes too high. This program requires that the studs be heat-treated approximately every 5 years. Excessive flaring of stud nuts to the extent that loss of thread engagement was experienced was corrected by replacing them with nuts of a higher-alloy material furnished by the turbine manufacturer. In a foreign-furnished turbine, failure occurred in bolting made of nickel-chromium alloy 80A material as a result of carbide precipitation banding. This material is also a problem in that it has a questionable ultrasonic-inspection property which makes it difficult to determine whether cracks exist.

All bolting in the turbine stop and intercept valves and the high-temperature sections of the turbine shell is checked by ultrasonic techniques during each inspection outage. When this practice was first instituted, it was not uncommon to find 50 percent or more of the bolts in a valve cover cracked or completely broken. Thermal cycling from frequent startups and stretch cycling the bolts for turbine inspections add to the problem of bolt breakage. Valve-cover cupping from temperature differentials overloads the stud's outer edge and results in cracking in this area.

A typical situation when ultrasonic inspection was first instituted in which several studs were cracked in the first one or two threads below the flange surface of an intercept valve is shown in Fig. 5.

Generator Stator-Winding Repairs

TVA's experience with thermal plant generator repairs ranges from minor iron repairs to complete rewinds. All generator windings have one-turn bars (half-coils) and range in size from 112.5 MW to 575 MW and can be divided into two major insulation systems--asphaltic and thermosetting. Operating experience shows that the asphaltic-insulated windings are subject to tape separation and require more frequent inspections and maintenance than the thermosetting-insulated windings. The few thermosetting-insulated winding failures have been caused mainly by looseness and abrasive wear, but the primary problem in generators has been tape separation of asphaltic windings. Specifications now call for the thermosetting insulation when replacing failed, weak, or damaged bars and when completely rewinding a stator. To minimize inservice failure, close physical inspections and suitability-for-service high-potential tests with the generator disassembled are performed at intervals of 36 months' operation on asphaltic-insulated windings and 60 months' operation on thermosetting-insulated windings. The test values used are either 1-1/4E + 500-V ac or 1.6(1-1/4E + 500-V dc) when E is rated phase-to-phase voltage. Of all of these generators, approximately 9 percent have required complete stator rewinding and 42 percent have had partial replacements of bars. Table 1 shows a comparison of TVA's experience with asphaltic and thermosetting insulations.

Generator Field Problems

Of the 64 generator fields in service, 9 are 4-pole fields and 55 are 2-pole fields. All 64 of the rotors are hydrogen cooled. The voltages range from 250-V dc to 550-V dc. No catastrophic-type failures that required replacement of rotor forging or field winding have been experienced. Problems that have been experienced are as follows:

1. Three fields developed thermal unbalance due to slippage of winding insulation that blocked the cooling-gas passages. A change-out rotor is being utilized to avoid a long outage to repair one of these.
2. Two fields developed grounds resulting from manufacturing defects. One was caused by a copper sliver and the other by copper dust left in the winding.
3. One field had an inservice inner radial-lead failure which physically damaged the stator winding, causing it to fail. All radial leads on 14 similar fields were replaced.
4. Six fields had several top turns isolated to minimize potential damage and to minimize the threat of forced outages caused by top-turn fatigue breaks.
5. One field has a small partial crack in a coil-jumper connection. This field is still in service, and the crack is being watched closely for progression.

STEAM GENERATOR EXPERIENCE

Steam Generator Tube-Metal Performance

Tube metals covered by the ASME code and operated within the specified limits have, with few exceptions, given good performance up to approximately 125,000 operating hours. The exceptions are:

1. Creep rupture of series 300 stainless-steel tubing before the industry recognized the problem and instituted H-grade heat treatment. It was necessary to remove, heat-treat, and reinstall the 300-series stainless steel in the superheater and reheater sections of 11 steam generators.
2. Exfoliation of oxide from the inside surfaces of high-temperature, 1-1/4-, 2-1/4-, 5-, and 9-percent chrome-alloy reheater tubing that carries over and causes solid-particle erosion in the turbine is also a problem in the steam generator. Exfoliated scale plugs close-return bends in reheat pendant elements, blocking circulation. This causes overheating and failure of the element. Steam generators with close-return bends are washed periodically with water through the individual circuits to remove the exfoliated scale. In later steam generators, TVA specifies that return bends in reheater pendant elements have a 3-in. minimum radius. This change was made on two large steam generators after they had been in service several years.
3. A steam-generator manufacturer recommended that a magnetic-particle inspection be performed on all bends of 75 degrees or greater in SA106C and SA210C piping and tubing of 4-in. diameter and greater to determine whether external marks or laps were present. The manufacturing flaws in these materials had become extremely critical during the cold forming, which lowered the material ductility which made them susceptible to catastrophic failure.
4. Failure of chromium-alloy tubes welded to stainless-steel tubes with 309 weld material because of carbon migration in the weld heat-affected zone. During the past two years, approximately 10,000 welds made with

309 stainless steel have been ground out and rewelded with nickel-chromium alloy 600, which has given good service in joining these dissimilar metals to date.

High-temperature chrome-alloy superheater and reheater tubing, operating within the design limits specified in the ASME code is beginning to show some deterioration from creep and oxidation in isolated instances after 125,000 hours.

Pressurized Furnace Maintenance

Pressurized furnaces have resulted in an increase in steam-generator tube failures because of stress tears in membrane or web-welded constructed waterwalls and fly-ash erosion from gas leaks at the roofs. Casing, roof seal, ductwork, and expansion-joint maintenance is much greater than on balanced-draft units because of cracks and tears from thermal distortion and inadequate design. Excessive gas leakage into a non-pressurized penthouse from the pressurized furnace causes high temperatures on hangers and other components and fly-ash accumulation of 6- to 8-ft depths overloads hangers and supports. The decision has now been made that all steam generators with pressurized furnaces must have the penthouse pressurized. This modification is now being made on a 950-MW unit.

Cyclone Maintenance

TVA operates six cyclone-fired units--three 330-MW units, two 700-MW units, and one 1150-MW unit. Cyclone tubes have been a problem on the three largest units since initial operation. The problems are primarily associated with slag erosion, arc damage at the base of studs, and iron-sulfide attack. Most all of the crotch tubes, re-entrant throat tubes, wrapper tubes, and face tubes have been replaced at least once in the 700-MW units.

External wastage caused by slag erosion on barrel tubes is progressing at a steady rate; and it now appears that replacement of all cyclone tubes in the 700-MW units will be mandatory within 3 to 5 years, or about 12 years from initial operation. About six or eight emergency outages are being experienced annually on each of these units from this cause. During each outage, three to six leaks in cyclone tubes are usually found.

Analysis of Forced Outages

An annual average of 350 steam generator forced outages has been experienced over the past 4 years in 57 operating units ranging in size from 125 MW to 1150 MW. Of the 350 outages, approximately 300 were caused by tube leaks or failures.

In an effort to maintain unit reliability, major replacement or rehabilitation in areas where excessive tube failures occur is made after an evaluation based on loss of generation, cost of repairs, and damage to the unit from frequent startups and shutdowns indicates it is justified. The central office staff maintains a record of all tube failures and makes frequent evaluations of the trouble areas along with comparisons between plants to determine when major repairs should be made. Figure 6 shows an example of steam-generator outages because of tube failures before and after major tube replacement. Figure 7 is a weighted-average study showing that failures on larger units are somewhat higher than on units below 500 MW, even though the study compares the new large units with the smaller steam generators where the tubing has approximately 100,000 operating hours.

STEAM PLANT AUXILIARY EQUIPMENT MAINTENANCE EXPERIENCE

Fly-Ash Removal Equipment

TVA's maintenance experience on 30 electrostatic precipitators ranges up to 13 years. Twenty-one additional precipitators are either under construction, purchased, or on standby units. The major problem areas affecting reliability and maintenance involve physical features of the collector design, ash-removal problems, and operating conditions such as gas temperature and sulfur content. The principle precipitator maintenance items have been associated with ash-removal systems, discharge electrode-wire failures, support-insulator failures, transformer-rectifier failures, and rapper and vibrator problems.

Feedwater Heater Experience

TVA's feedwater heater experience can better be classified into the types of tubing used and the experience with the different tube metals.

Copper-Base Tube Materials--In admiralty tubing, failures have occurred because of impingement erosion in "U" bends from high velocities in the low-pressure heaters. Additionally, there were failures occurring from stress-corrosion cracking when tubes were not annealed properly after final bending and straightening. Of the 41 top low-pressure heaters, 14 have been retubed; and the others will require retubing soon. All of these are on older units.

Failures of 70-30 cupro-nickel tubing occurred because of steam-side copper exfoliation. Now that the older units are used more for peaking service, an effective nitrogen blanket during unit shutdown may be required. Twelve of these heaters have been retubed with stainless steel. All of these are also on the older units.

Nickel-copper alloy 400 has given fairly good service with the exception of collecting a copper "snake skin" on the inside of the tubing. During early years of operation, the copper foil would release from the inside of the tubes and carry over into the steam generator and plug the downcomer screens. The problem has diminished in recent years.

Carbon-Steel Tube Material--TVA and the industry have experienced pinhole leakage in the tube-to-tube sheet welds on carbon steel tubes welded to a carbon-steel tube sheet having a low-carbon-steel overlay. Where TVA has this combination, the third from the top heater on the unit has been particularly troublesome, requiring wholesale reweldings with insertion of stainless ferrules in the inlet ends and installation of flow straighteners as routine measures. No unusual problems have been encountered using carbon-steel tubes with a nickel-chromium alloy 600 overlay on the tube sheet.

Thus far, excellent results have been experienced from the use of stainless-steel tubes and nickel-chromium alloy 600 tubes in high-pressure heaters. Type 304 stainless steel is pretty much the standard for replacement tubing where there has been a problem with the other materials.

Steam Condenser Experience

Admiralty Tubing Material--In the older units, the entire condensers had admiralty tubing, both in the main and air-removal sections. The older units operated with lower ammonia concentrations than the large new units. Several problems have been encountered with the admiralty tubing as follows:

1. One condenser required retubing because the tubes failed from stress-corrosion cracking due to locked-up stresses in tubing that was not annealed after final straightening.
2. In air-removal sections with ammonia-laden condensate, there have been tube failures because of wastage on the condensate side at the support baffles.
3. Stress-corrosion cracking immediately behind the tube sheet where the rolling stresses and residual stresses have made the material susceptible.
4. Erosion and thinning of the inlet end of the tubes after years of operation.

Cupro-Nickel Tubing Material--In the later units where the ammonia concentrations are higher, admiralty tubing was abandoned in the air-removal section and 90-10 cupro-nickel tubing was used. Because of economics and acceptable service, 90-10 cupro-nickel has prevailed over the 70-30 cupro-nickel. No unusual problems have been encountered with these materials in the condenser applications; therefore, the 90-10 cupro-nickel is the favored material for replacing the admiralty and for new installations in the entire condenser where the ammonia concentration is expected to be high. Both seamless and welded 90-10 cupro-nickel tubes are being used.

Stainless-Steel Tubing Material--The use of stainless steel in main condensers has been minimal. A few tubes were installed for erosion protection in the top of one condenser and in the air-removal section of three others. Generally, the stainless steel has not performed well because of pitting corrosion unless an inservice cleaning system is used.

Chimney Maintenance

The trend to large units, along with increasing concern about air pollution, has caused a progression from 50-ft-high metal chimneys on units built in 1951 through intermediate heights with brick linings to 1000-ft concrete chimneys with corrosion-resistant alloy steel liners. The first of the latter type is to go into operation this year, so maintenance problems on the steel-lined chimney are still unknown in TVA.

Metal Chimneys--The original 50-ft-high steel chimneys have been converted to 150-ft heights. All of these chimneys have had serious corrosion in the upper two-thirds. Reinforcement bands at the ring joints and ladder connections were added in eight of the chimneys because the metal had wasted to a critical point. Two gunnite-lined metal chimneys, 275 ft high, have presented no problems.

Free-Standing Brick Liners--There are 25 concrete chimneys in operation, 250 to 350 ft high, with free-standing brick liners. This type of chimney has been in operation since 1953. Failures in the upper 25 to 30 ft occurred in the brick liners of 10 chimneys. The acid-proof mortar had deteriorated in each case. Some of these chimneys have failed twice. TVA has continued experimenting with different acid-proof mortars in an effort to stop the failures which seem to be prevalent on units with the greater number of cold startups. Inadequate clearance between the shell and liner has also contributed to problems.

Corbel-Supported Brick Liners--There are 10 concrete chimneys, ranging in height from 400 to 600 ft, with corbel-supported brick liners. A major problem experienced is failure of the corbel seal at the top of the independent liner and at each corbel. Cracking and loss of brick have occurred in the 225-ft independent liner below the corbels of two 600-ft chimneys. Bolts were found sheared in the steel bands on the outside of the liner, and the liner had cracked and moved outward. These failures were apparently the result of construction errors.

Three 400-ft positive-pressure chimneys have been in operation since 1959. Extreme acid attack is being experienced on the concrete shell. Identical problems were experienced in this country from acid attack on similar pressurized chimneys with high velocities and corbel-supported brick linings. This design has been discontinued for power plant use. Corrosion-resistant steel linings have been installed at some locations; however, TVA has kept these chimneys in service by a rigid maintenance program of filling cracks and holes with specified grout mix and installation of metal bands at selected locations.

Concrete Liners--Two 800-ft-high chimneys with concrete liners are in operation. These liners have type 347 stainless-steel sections at the top of the chimney. The concrete liner in one unit in operation since 1966 developed hairline cracks which have not affected the integrity of the structure. However, the inner surfaces of the liners are undergoing progressive sulfuric-acid penetration. Numerous coatings have been tried to protect the interior of the concrete liners, but none have been successful in adhering to the liner for more than a few months.

Ash-Disposal Pond Maintenance

An intensified maintenance program on the ash-disposal pond dikes is followed to assure that ash is not released into nearby streams. Regular inspections assure that the dikes are maintained in a reliable condition. Erosion of the dike slopes is eliminated by vegetation and proper drainage. Also, low water levels are maintained in the pond to minimize both the hydraulic head on the dikes and the amount of water that could be released in the unlikely event of a dike failure.

HYDROELECTRIC PLANT MAINTENANCE EXPERIENCE

Concrete Growth

One of the unusual maintenance experiences encountered on a hydro unit was the extensive realignment of the turbine and generator that was necessary to correct for concrete growth. The concrete at this particular plant underwent a slow but significant expansion through the years; and numerous adjustments, including grinding the throat ring to provide radial running clearance, rerounding the generator stator to maintain an even air gap, and lowering the rotating element to provide proper runner hub-to-head cover clearance, were necessary to maintain this unit in operating alignment.

Other units at this plant are now undergoing a major realignment program which includes regrouting the generator-stator sole-plates to restore proper vertical clearances, recentering the rotating elements to provide radial clearances, and other alignment adjustments necessary to place the units in good operating condition. Similar trouble has not been experienced at any other plant.

Generator Rewind Experience

TVA has 113 hydrogenerator units in service, and the average age is 30 years. Since 1953, the stator windings in 20 hydrogenerators have been replaced, and two windings are on order for replacement in 1972. The average life of the original windings requiring replacement was 21 years. Additionally, the complete stator was replaced on eight hydrogenerators that were rehabilitated after 42 years of service. Although there are other causes, the majority of the generator coil failures are due to inter-turn insulation failures caused by internal corona damage. The inter-turn failures result finally in a failure to ground. The practice is to electrically cut out and bypass damaged coils and return the generator to service. When a winding reaches the point where reliability is uncertain and the load is limited, it is replaced with a new winding having a thermosetting-insulation system and an increased kVA rating. The maximum number of coils cut out on one generator in the TVA system is eleven.

Cavitation Repair

Cavitation repair is a common maintenance requirement on water wheels. For many years, the only repair made was to weld the cavitated areas with stainless-steel electrodes. This is costly and time consuming, but is still required on severely eroded areas. A few years ago, experimentation showed that epoxy resins give good results where the cavitation is light to moderately heavy. In these cases, it protects almost as well as stainless steel. Approximately 75 percent of the cavitation repairs are now being made with epoxy. A substantial saving is realized since the epoxy can be applied in one-tenth or less the time required for welding.

Other Hydro Maintenance

Other areas of general hydro maintenance include the necessity of rerounding generator stators to prevent overheated guide shoes. In one case, an out-of-round stator contributed to fatigue failure of the rotor-iron support ledges, allowing the iron laminations to drop on one side of the rotor. On older units, the wicket-gate stems and bushings are wearing to the point of excessive clearances and are becoming badly corroded and pitted. The correction for this is to coat the stems with stainless steel and install new bushings.

NUCLEAR PLANT MAINTENANCE

Nuclear plant maintenance is expected to begin with the startup of TVA's first nuclear unit in the latter part of 1972. It is recognized that nuclear maintenance will require much more emphasis because of quality-assurance requirements and radiation exposure. Spare parts and maintenance procedures must meet exacting standards. Special tools and techniques for repair of radioactive equipment require more special consideration than those used in a conventional plant. The inservice-inspection program will be a major maintenance aspect of each refueling outage. The number of permanently assigned craftsmen will be less than in a fossil plant of comparable rating. This, together with radiation exposure, will entail more outside assistance from the service shops and supervisors from the central offices on major inspections and repairs. Maintenance instructions, quality-assurance procedures, and inservice-inspection programs are being prepared. Initially, preoperational baseline- and inservice-inspection work is being contracted.

It is planned to inspect one section of the turbogenerator during each annual refueling outage, resulting in a complete inspection by 35,000 operating hours.

CONCLUSION

TVA has attempted to exercise a preventive maintenance program to provide the highest possible reliability in a rapidly expanding steam-generating system of prototype equipment. The steam system was built during the last 20 years to supplement the hydro system which began one-half century ago. While the program has generally prevented catastrophic failures of equipment, numerous problems attendant to technology and size extrapolation have been coped with in advancing the state of the art of electrical generation. Plant maintenance, central coordination and assistance, scheduled inspections, and cost-benefit analysis of major replacements are used in the philosophy of accomplishing the desired results.

There are two influences upon maintenance activity that could be improved. Both of these would have a positive impact in reducing outage time and improving reliability of generating equipment. These two factors are (1) productivity of utility employees and (2) equipment-supplier service.

Maintenance work is admittedly one of the most difficult manpower efforts to measure in terms of production rate, but there are some indications that productivity in many respects is less today than at times past.

One also wonders if the utility-equipment suppliers' product service people heard what the sales people were promising with the orders for the big, new, high-powered models. If the manufacturers desire to furnish equipment on a steep learning curve, there should be an equal desire to follow through the learning period with prompt engineering decisions, spare parts, and responsibility. Some manufacturers' service departments are rising to the challenge with the customers' needs in view. This is a healthy sign.

The generating equipment suppliers and the utilities have together pioneered an energy supply that has probably more than any one thing made America industrially great. Managers and employees of both segments of this industry must remember that the end product of our effort is a commodity we not only provide but also purchase.

TABLE I

COMPARISON OF ASPHALTIC AND THERMOSETTING INSULATED WINDINGS

IN THERMAL PLANT GENERATORS

IN THE TVA SYSTEM

Areas of Comparison	Type of Insulation: Asphaltic		Type of Insulation: Thermosetting	
Total stator windings[a]	25		39	
Age range (years)	6-20		1-19	
Average age (years)	15.0		12.5	
Total bars (half-coils) in service	2,304		3,756	
Total bars replaced (not including complete rewinds)				
Top bars	244		14	
Bottom bars	15		8	
Machines involved	17		10	
Causes				
Tape separation	258[b]		-	
Looseness, abrasive wear, or physical damage	1		22[c]	
Complete rewinds				
Insulation failure	4		1	
Field radial lead failure	-		1	
Cooling systems	No. of Generators	MW Rating	No. of Generators	MW Rating
Conventional				
Hydrogen	23	112.5-180	16	112.5-184
Intercooling				
Hydrogen	-		9	150-250
Water	2	250	8	325-575.1
Oil	-		6	150-277.7

a. Generators on 2-shaft units counted separately
b. Includes 1 inservice failure
c. Includes 2 inservice failures

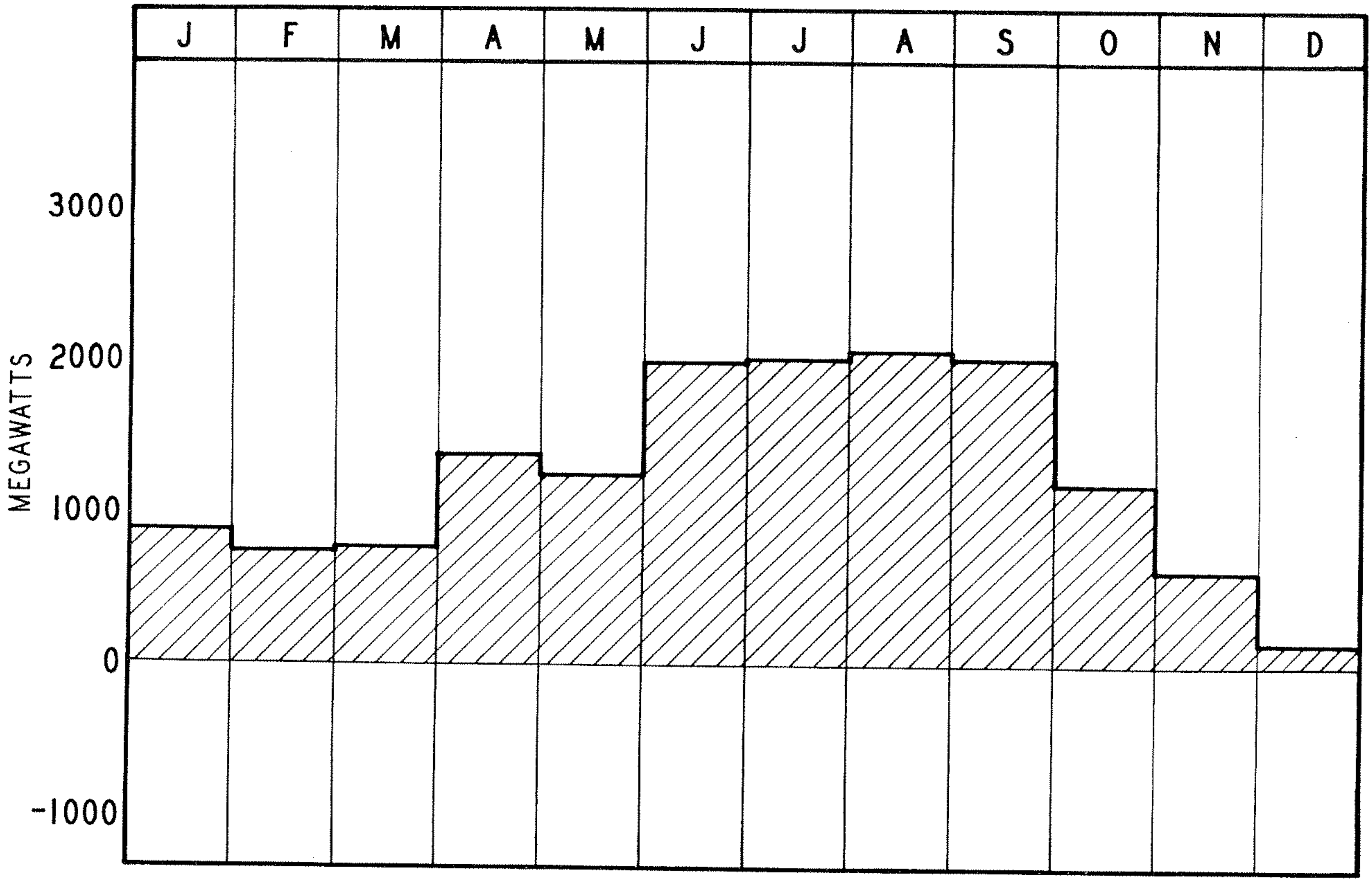


FIG. I CAPACITY AVAILABLE FOR MAINTENANCE 1965

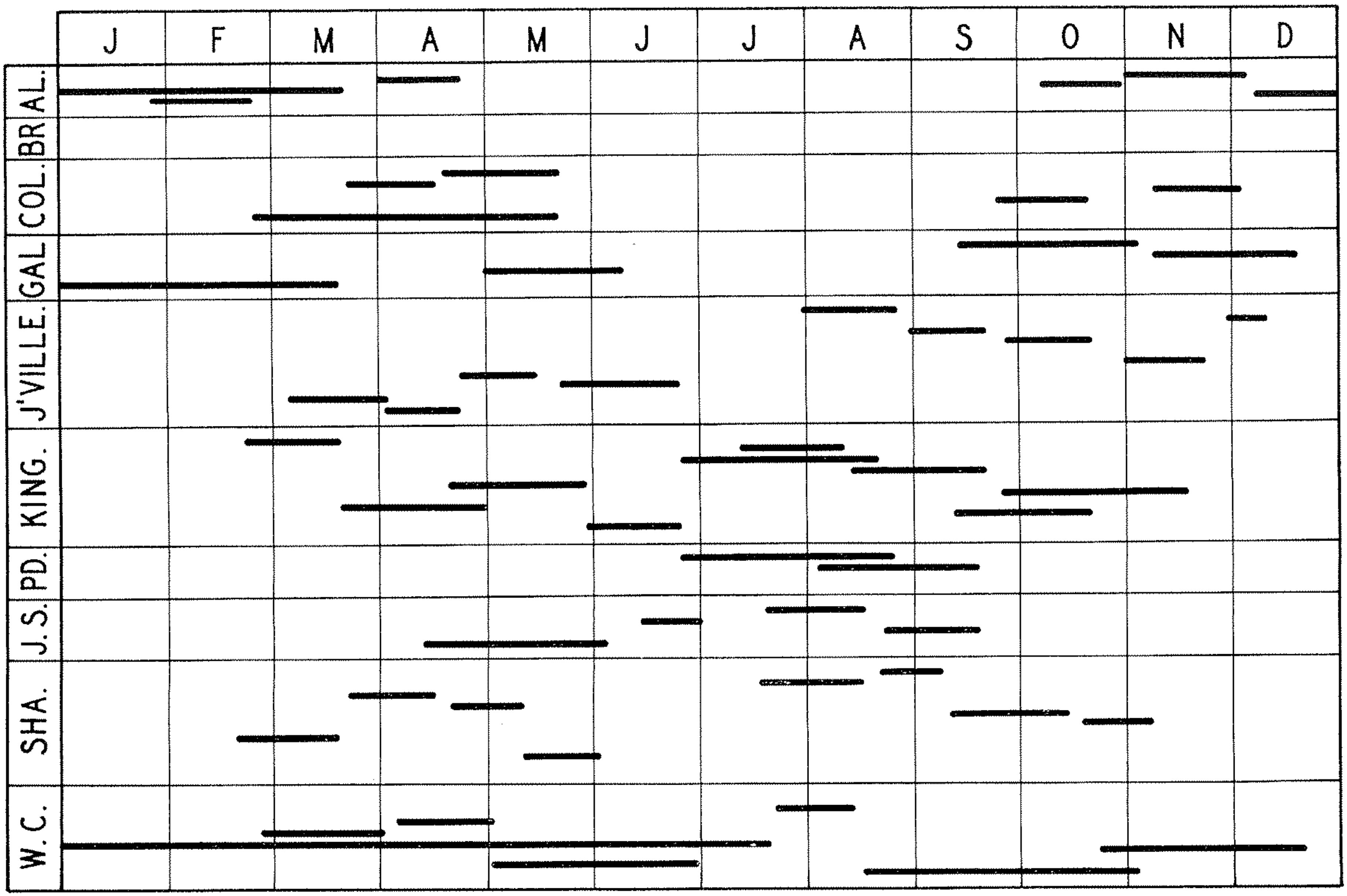


FIG. 2 OUTAGE SCHEDULE 1965

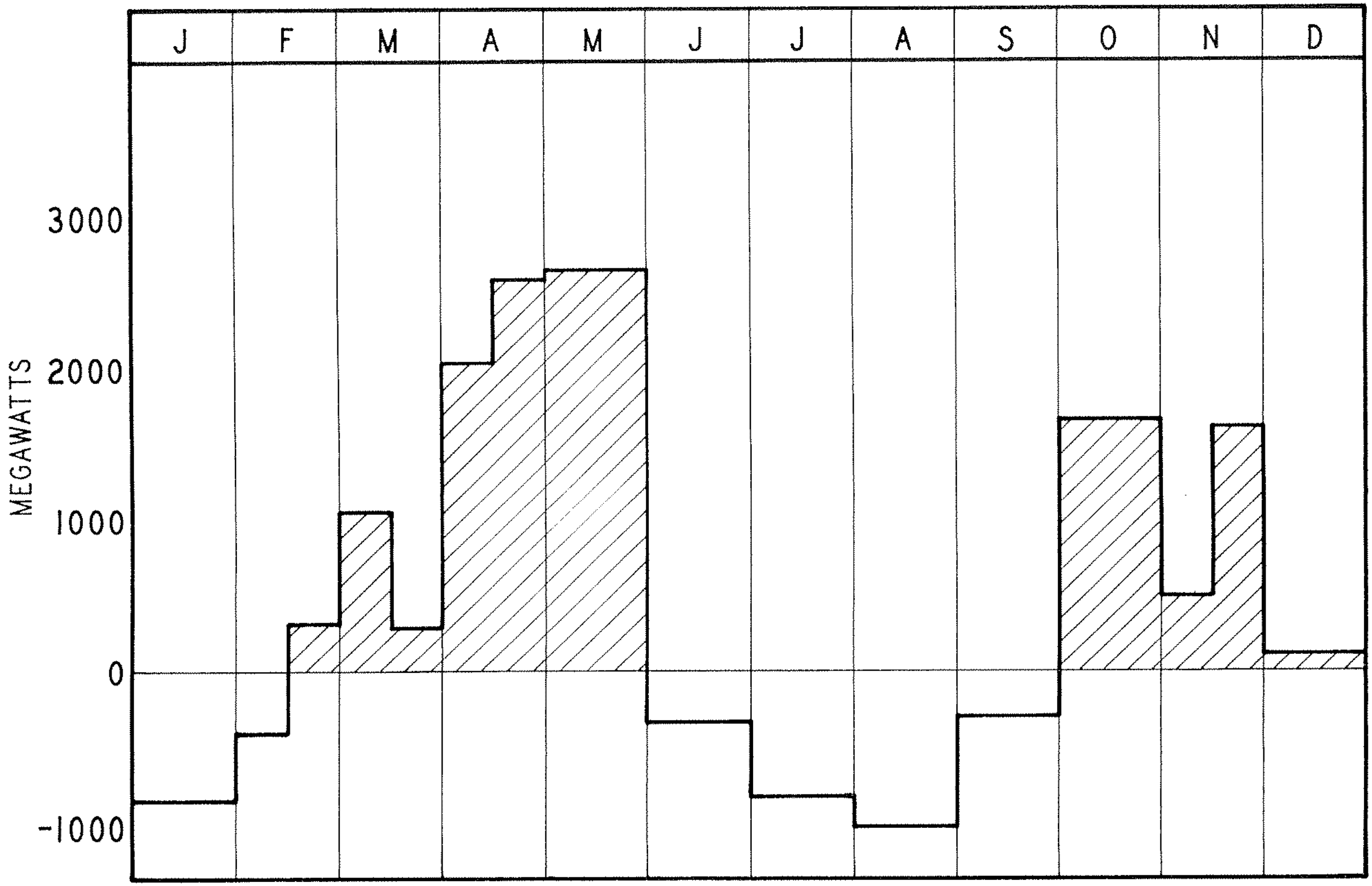


FIG. 3 CAPACITY AVAILABLE FOR MAINTENANCE 1971

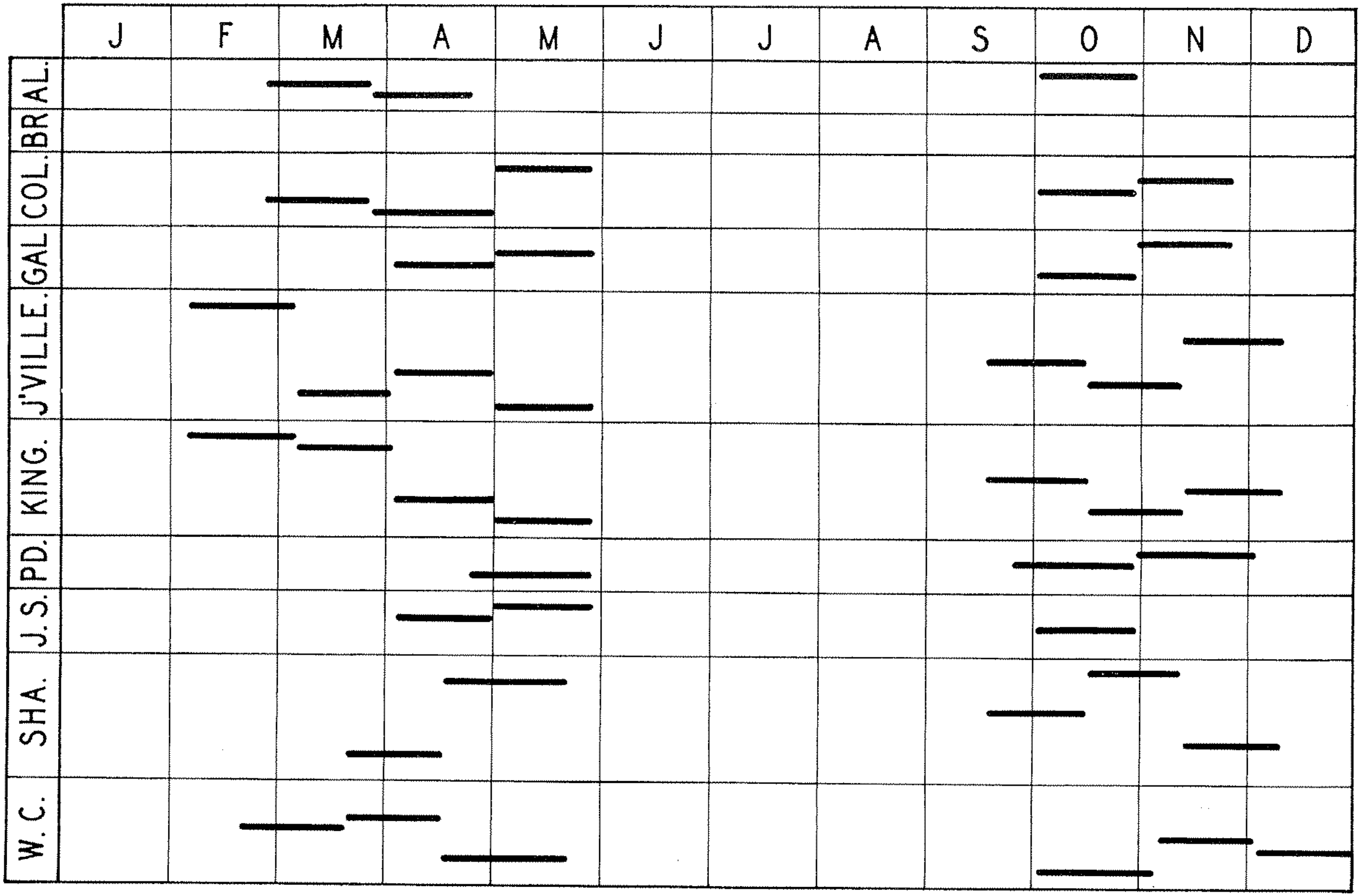
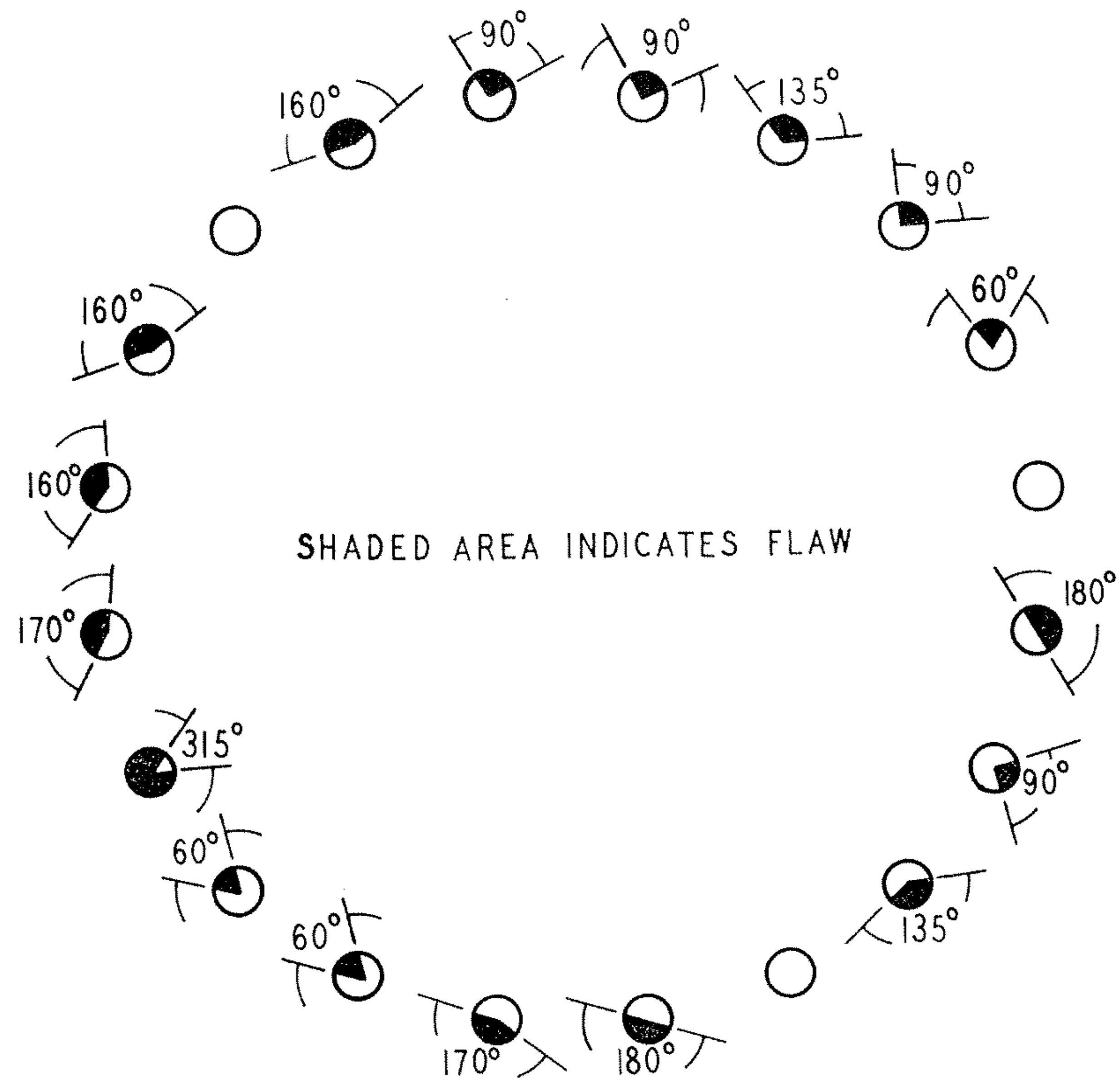
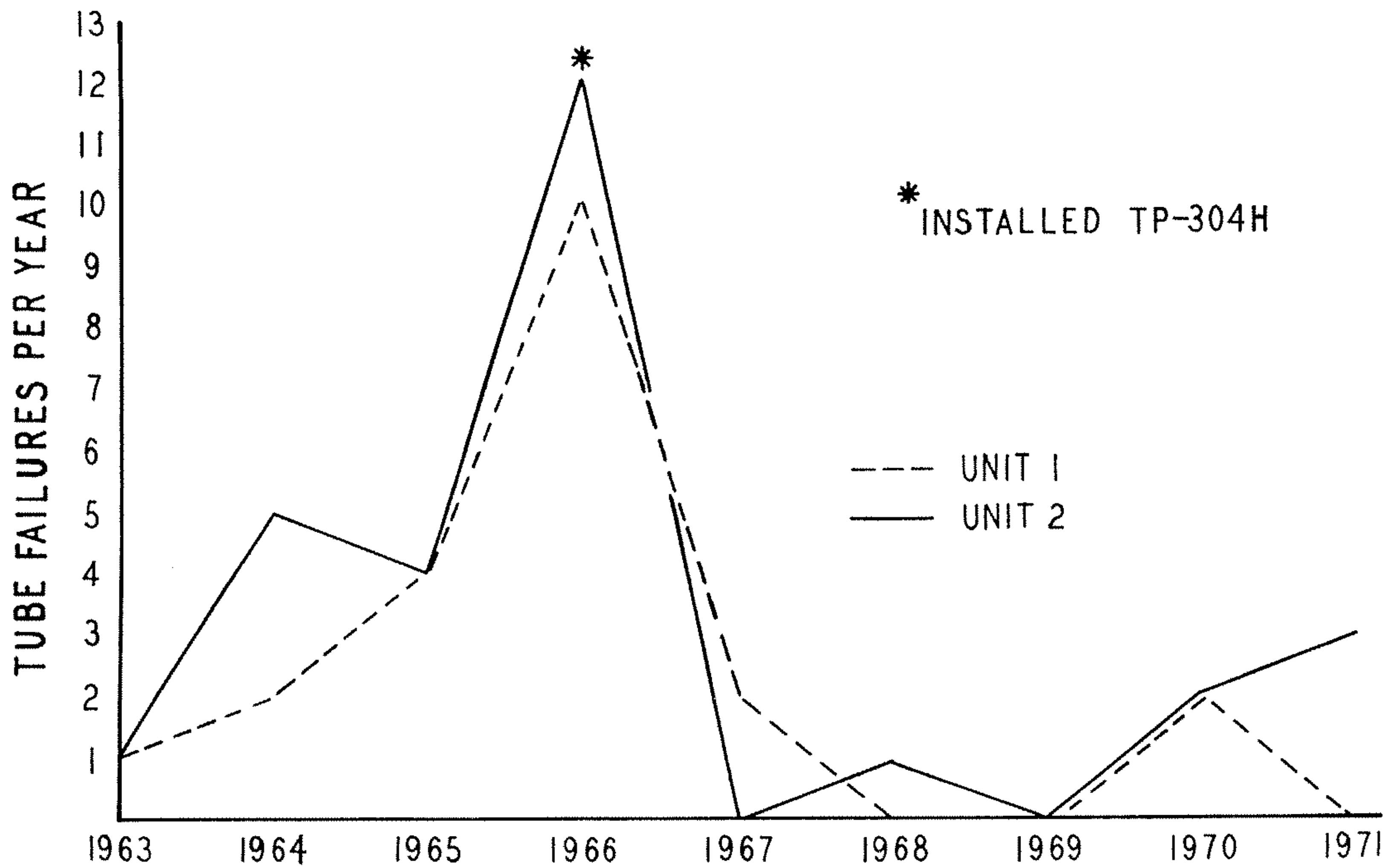


FIG. 4 OUTAGE SCHEDULE 1971

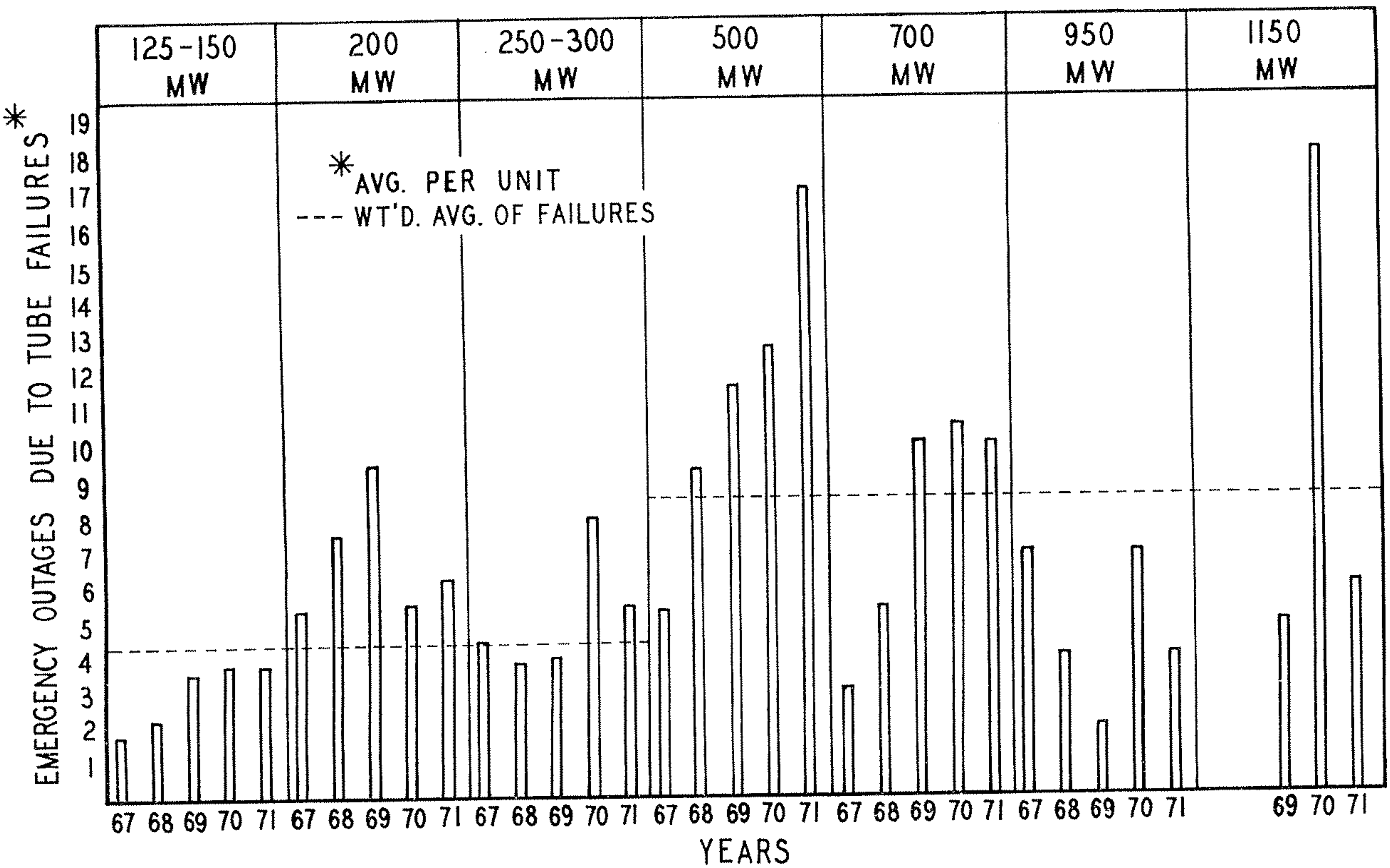


CRACKED STUDS IN INTERCEPT VALVE
FIG. 5



TUBE FAILURES - BEFORE AND AFTER MODIFICATION

FIG. 6



TUBE FAILURE COMPARISON BY UNIT SIZE
FIG. 7