Abstract

Operational experience at the 530 MW Raccoon Mountain underground pumped-storage plant can be relevant to other large hydro facilities. A number of unusual features were incorporated and individual unit size was only recently overtaken elsewhere. Direct water cooling of rotor and stator windings has been successfully applied to salient pole machines. A number of problems, including difficulties with oil-filled 161 kV current transformers, and some mechanical aspects, are reported. Designed for remote supervisory control, the plant has required closer attention. Operating statistics are included.

Introduction

The Raccoon Mountain Pumped-Storage Plant located on the Tennessee River 6 miles west of Chattanooga, Tennessee, has four reversible units, each having 425 megavoltamperes (MVA) rated capacity at 0.9 power factor (PF) as generators and 540 000 horsepower - 403 megawatts (MW) - in the pumping direction. The lower reservoir, Nickajack Lake, was part of the system already existing on the Tennessee River. The upper reservoir, a little over 500 acres (200 hectares) in area, was created for this project, by placing a dam across the valley on top of Raccoon Mountain. The hydraulic head varies in the range 896 to 1040 ft (273 - 317 meters). Stored water provides for full 530 MW generation for 15 hours, with a further 5 hours output, falling to 1 350 MW. The reservoir can then be refilled in 29 hours. Construction was begun in 1970 and delayed about two years by unsatisfactory metallurgy in the stay ring of the turbine; the scroll case required redesign. The first unit was run for trial in May 1978, the last unit was placed under power system control in August 1978. However, a period of fairly intensive modification continued for another two years after this.

The final cost of the plant was 328 000 000 dollars, or $193/kilowatt of the 1 700 MW capability.

The general plan and section of the site, with its underground power/plant, are shown in Figure 1. The 161-kV and 500-kV switchyards are located in a relatively flat area about a mile (1.6 kilometers) to the East, close to the upper end of the Lake. A single line diagram of the main electrical connections is shown in Figure 2 and a more detailed view of the powerhouse chamber in Figure 3.

This paper comments on experiences gained while bringing the equipment into service, and since. Until quite recently, these units remained the largest reversible pump turbines in service anywhere in the world; problems experienced in their operation can therefore be relevant to planning of similar undertakings, as well as to operation, elsewhere.

![Figure 1. Raccoon Mountain Plant Site](image)

Table I is a summary of operating results for the five most recently available years. The Fiscal Year (FY) runs from October of the preceding calendar year through September.

<table>
<thead>
<tr>
<th>FY</th>
<th>81</th>
<th>82</th>
<th>83</th>
<th>84</th>
<th>85</th>
</tr>
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<tbody>
<tr>
<td>Unit % Operating Availability</td>
<td>64.2</td>
<td>76.8</td>
<td>80.9</td>
<td>79.2</td>
<td>93.88</td>
</tr>
<tr>
<td>% Capacity Factor (Gen.)</td>
<td>65.8</td>
<td>61.0</td>
<td>60.0</td>
<td>60.0</td>
<td>60.0</td>
</tr>
<tr>
<td>% Conversion Efficiency</td>
<td>79.17</td>
<td>79.20</td>
<td>79.27</td>
<td>79.22</td>
<td>79.37</td>
</tr>
<tr>
<td>Station Use % Gross Gen.</td>
<td>1.05</td>
<td>1.06</td>
<td>1.02</td>
<td>1.08</td>
<td>0.96</td>
</tr>
<tr>
<td>Station Cost $/MWh Gen.</td>
<td>2.48</td>
<td>2.57</td>
<td>2.78</td>
<td>2.91</td>
<td>2.21</td>
</tr>
</tbody>
</table>

The dramatic improvement in operating availability in 1985 was due to ability to allow greater intervals between cavitation outages and also to the completion of changes resulting from earlier problems. However, two major failures early in FY 1986 (Stator 1 and Turbine Seal 3) will break the continuity of this better record. It is interesting that in spite of increased unit availability in 1985, utilization...
(capacity factor) is hardly increased. Capacity factor is based on generation figures. Total utilization, including pumping, may be closely approximated by multiplying the generation figure shown by 2.2. Heaviest monthly use is in July and August, but even then, the generating capacity factor seldom exceeds 15%, or 33% total utilization of the plant. The units are seldom run at part load due to vibration experienced in the "generate" direction and from consideration of pumping efficiency.

The overall efficiency of conversion is based on MWh metered at the generator/motor terminals. No correction is made for runoff from the watershed which extends to only a very narrow strip around the lake. (One inch of rain on the lake is equivalent only to 6 minutes generation for one unit—evaporation and any leakage will tend to cancel this.) A correction is made for change in lake level over the period.

Station use includes energy metered to pump starting, corrected for regenerative braking. Station costs, based on gross generation, do not include cost of energy used for pumping, or station service, or capital charges.

Vibration

Vibration, together with generator lower bearing high temperature, was the main problem in the early stages of running. The stiffness of the shaft support system was augmented wherever possible in the field. Such expedients as continuously welding down generator coverplates, were used to help stiffen the bearing supports. Changes were made in the upper and lower generator guide bearings also, to make the oil film itself stiffer. To achieve this, clearances were reduced and the oil grooves removed from the guide bearing pads. The bearing surfaces were remachined with a diameter slightly greater than that of the corresponding runner surface. As far as possible, oil level was raised, but this conflicts with the need to minimize oil leakage. The shafts themselves are of forged steel, 44 inches (1 118 mm) in diameter, rotating at 300 rpm, and were not altered.

Some dynamic balancing was carried out. Problems of inconsistency were found to be due to felt pads installed to inhibit the leakage of oil vapor from the generator lower bearing housing. Rubbing on the shaft, these pads caused thermal distortion and inconsistent balancing readings until they were removed.

As experience was gained, it emerged that strict attention to shaft alignment and bearing clearance had more influence on vibration than had balance weight distribution.

Valuable lessons were learned about the magnitude and characteristics of vibrations encountered in large reversible pump-turbines.

The upper generator bearing experiences most vibration in service, showing readings in the range 1.5 - 6.0 p-p mils (0.04 - 0.15 mm) under normal operating conditions; 6-8 mils indication are considered sufficient to investigate causes; 10 mils is the alarm point. Vibration at the lower generator bearing is normally in the range 1.0 - 3.5 mils p-p (0.03 - 0.09 mm) with alarm at 4 mils. The turbine bearings show vibration of 0.5 - 2.0 mils p-p (0.01 - 0.05 mm) in the generate direction but more, 1.0 - 3.0 mils p-p (0.03 - 0.08 mm), when pumping. These readings are peak to peak thousandths of an inch,

Fig. 2. Main Electrical Connections

Fig. 3. Underground Powerplant Cross Section
measured by accelerometer-type detectors mounted on the outsides of the bearing housings, as effectively close as possible to the guide bearings themselves.

It is perhaps interesting to speculate why the test flux affected the core so severely. Near the face of the core, eddy current potential is oriented vertically across the plane of the laminations. Due to non-uniformity, this potential tends to concentrate at those points along the core where inter-laminar resistance is highest. Breakdown and heating then occurs at the weakest point in the relatively good insulation. This testing problem would only be expected to occur in stators like those of the subject machines, in which the laminations are ungrounded except for the pressure plates. Our experience indicates that stator induced flux tests should only be made in the field at reduced levels, if at all, except for machines which employ bonding along the outer edge of all laminations.

When the stator flux is excited from the rotor field poles, regular spatial reversals of vertically flowing eddy current around the core will be associated with the alternation of the polarity, so the area contributing current (or potential) to an individual weak spot is much reduced. Stator segmentation probably reduces the likelihood of eddy current buildup, even under testing conditions; but even so, there are multiple rotor poles associated with each stator segment (in this case, eight) to further mitigate the severity of local heating.

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Generators/Motors

The compact design, following from the adoption of direct water cooling of the windings, resulted in machines of relatively low inertia (Mg·s²). This led to concern about stable operation of the units during system disturbance. Field forcing capability was one expedient chosen to overcome this problem and led in turn to concern for possible overheating of the field windings. To avoid this, it was decided to increase the cross-sectional area of the main flux path in the poles and for this reason it was chosen to lengthen them (axially) at a late stage of manufacture. To avoid possible consequent excess stator core end heating, due to eddy currents from increased end-flux (axial flux), additional short axial slots were milled in the laminations on site between all the conductor carrying slots at the ends of each core. (The windings were in place during this process.) When the stator was assembled, core flux tests were carried out to check for possible resulting problems in the laminated core iron. Although not associated with the slotting, a number of quite intense hot spots appeared randomly on the core face. The problem was thought to be due to moisture absorbed into the interlaminar insulation during two years or so storage of the stator segments on site. Although prolonged heat was applied to the stators, mainly by circulating heated water in the hollow stator windings, the weakness was never completely eliminated. However, while no similar experiences occurred in service, the problem caused considerable concern at the time, and also delayed the first running by several months.

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Individual conductor strands (which are smaller than those of the rotor) near the ends and from the point where the strands at each end of the stator coil side form a single water path. The repair technique is to draw epoxy resin into the leakage path by applying vacuum to the interior (water path) of the conductor. So far, damage has not resulted in time kept in service for limited periods with small leaks of this type in existence.

There has also been found a tendency for leaks to develop in the copper "U" tubes carrying coolant between the top and bottom coil sides (Current is carried in an independent brazed connection). These "U" tubes are also used to locate the insulating coil end sleeves surrounding the "knuckle" of the coils. Vibration which was wearing away the copper was controlled by adding Dacron felt strips, held to the copper tube by epoxied tapes. No epoxy is applied at the point of contact between the tube and the cap support, to keep the Dacron resilient at that point.

Two serious winding failures have been experienced following heavier wettings of the stator windings. The first occurred in unit No. 3 stator in September 1972, and was due to raw water, leaking from a flange in the stator housing, being picked up by one of the motor-driven cooling fans and sprayed onto the lower end turns of the stator winding. Evidently it accumulated in the cellular, plastic foam-filled, insulating sleeves which cover the otherwise exposed conductor end connections (knuckles). In December 1985, a leak from the demineralized coolant connections at the top of the stator of unit 1 apparently ran down the core and windings and similarly accumulated in the insulating sleeves at the lower end turns. Widespread flashovers occurred in each case, although many of the half-cells could be repaired by cleaning, painting and electrical and hydraulic testing. In the first case, which involved all three phases, damage to seven bottom bars required the removal of 33 top bars also, to provide access. In the second case, which was apparently limited to two phases, damage to two bottom bars also required the removal of 25 top bars (The 23-kV wave winding occupies 216 slots). In each case, the fault appears to have progressed around the winding in the direction of rotation, though it is difficult to decide whether this is due to arc propagation or the progressive disturbance of water preceding the arcing. Fortunately, with these separate half-turn windings, it is possible to replace a limited section of the winding without disturbing a much wider area. In more conventional hydro-generator windings, it is necessary to lift a large number of coils, each a little more than the next, to expose the damage. The distortion involved can lead to damage to the coils disturbed. However, repair of half-turn windings is still expensive and time consuming.

The leakage in the first incident came from a supply pipe to a flange and the likelihood of similar incidents could be reduced by rearranging the raw water piping.

The second incident originated at a special tee connection. At those points at the top of the winding where the strands are stranded (four coil sides) the connecting copper "U" tube, previously described, is replaced by a tee connection. The teflon hose from the supply or return coolant header is connected to the bottom coil side through a stainless steel fitting. The complementary top coil side is connected through a copper "ell" which tees into the stainless steel and is secured by solder. It was in the copper "ell", directly adjacent to the stainless steel, that a peripheral failure in the copper occurred, initiating the leakage of coolant. Metallurgical examination showed that the copper "ells" had possibly been affected by heat when soldered in. These "ells" were all replaced, using new copper and a lower temperature solder.

It may be that fatigue at the junction was increased by slight looseness in the slot wedges, which was found when the stator was examined. Ripple filler was replaced in five of the slots, which were then tightly rewedge. At this point unit 1 had operated commercially for 6 400 hours generating with 1 682 starts and 8 300 hours pumping with 1 393 starts. All units have very similar operating records, and it was decided to rewedge all stators, within a year of this incident if possible. TVA had not, before this incident, made use of radio frequency (RF) monitoring (for example Partial Discharge Analysis or PDA) to detect coil looseness. However, this is now being addressed.

Upon first consideration, it would appear that coolant leakage could be detected through flows and changes in level in the makeup connection or by change of level in the coolant header tank. However, there are legitimate flows and changes in level associated with temperature change following the load change. Such changes tend to be more rapid for hydroelectric machines than for their thermally driven counterparts, and the flows are of a magnitude comparable with the flows associated with the leakage which occurred, for instance, in the December 1985 case. To take care of the necessary flows, the generator manufacturer recommends that the main water circuit be connected to the header tank by a pipe of no less than two inches (50 mm) diameter, with no serious restriction to flow as can be presented by sensitive flow meters. A platinum resistance flowmeter, offering no effective obstruction in the two-inch pipe and having a range of 0.25 - 5 gallons per minute (1 - 19 litres/min), has been identified and will be tested and further appraised for possible use as a protective device. As an interim precaution, the header tank low level alarm has been changed to trip, in the belief that occasional inadvertent tripping is preferable to winding failure. TVA has experienced leakage of coolant in hydrogen cooled turbo-type generators.

There were a number of cases in which no damage was apparent against damage in those cases: any water tends to be collected in a liquid alarm which warns of its presence; the pressure of hydrogen slows the leakage into the stator and often prevents it altogether; tee junctions are not used in such proximity to the winding; and the winding is more completely covered (in one design the winding was encapsulated at TVA's insistence). There are a number of betterments which might be suggested in the coil end area of the Raccoon Mountain generators: for instance, more protective shielding at the front section; greater concern for water entrapment would be most desirable; however, space is at a premium so that the overall arrangement is a compromise. In a completely new design of the winding, the coolant connections might be removed to the bottom of the stator, leakage would then fall away; also competition for space between outgoing electrical connections and coolant supply and return would be avoided.

Copper oxide deposition within the hollow winding conductor at the upper end of the coolant circuit was reported by the manufacturer to be a potential cause of failure due to overheating following flow restriction. It was stated that this oxygen reaction could be inhibited by keeping the alkalinity of the "pure" water in the range 8.0 to 8.5 pH value (where
periodic is control mixture of (Na with hydroxide on one samples of the resin containing sodium hydroxide to have this desirable effect on the water. Because the deliberate use of Sodium form resin resulted in quicker exhaustion of the bed, its use was discontinued, although pH of all units is still checked at longer intervals (yearly or after significant known changes) in case circumstances may alter. In the case of any water cooled generator, oxygen can be picked up through Teflon hose connections, etc. Hydrogen atmosphere generators should be less susceptible to this, although the pump shaft seal can still be a source of dissolved oxygen for them. Cooling of the lower guide and thrust bearings was found to be inadequate in service and redirection of the oil by added baffling and reorientation of the discharge from the piping connecting with the external oil/water heat exchangers, was very early necessary.

Serious cracking was discovered in the main shaft of generator 4, at the top of the recess occupied by the inner oil retainer (stove pipe) of the lower bearing housing. It was caused by heavy rubbing against the retainer. Need was indicated for somewhat closer control over metallurgy, in the specification of the shaft. A detailed discussion of this problem has been published [5].

Cracking of the flat aluminum rotating rotor covers which reduce windage losses required redesign of their supports.

Pump Starting

The static (semi-conductor) rectifier-inverter starting equipment has operated almost without interruption. It has been shown to be sensitive to the effects of high resistance connections, generating noise on the supply side. Average energy used to accelerate and synchronize one unit is in the range 800 - 900 kwh. To limit operation of the generator switchgear, regenerative braking is seldom used, but appears to return 200 - 300 kwh per braking.

If this converter is unavailable, back-to-back starting is possible between any pair of units and has been proven, and occasionally used in service and for training. The last unit, used in the generate mode for starting another, is itself left without means for being started in the pump direction.

Generator Switchgear and Disconnects

The manufacturer of the 3 500 and 5 000 MVA high pressure air gap generator, synchronous generator, strongly recommends detailed maintenance after a fixed amount of use. For instance, in the case of the unit breakers, about 4-5 days maintenance is performed after 2 000 operations (or 4 years). But after 4 000 operations (8 years), 6 weeks maintenance is needed. Low voltage breakers connect (and three open) in the pump-starting cycle (converter) - three close (and four open) for regenerative braking (converter) (none close and only one opens with mechanical braking.). The limited number of operations available and the extent of the maintenance recommended has made the overhaul of these breakers an important factor in planning maintenance for the plant. Discontinued use of the starting equipment for regenerative braking saves as many as 1 000 of these circuit breaker operations per month overall.

It would perhaps be advantageous in a future design to use load-break switches for generator switching, depending upon circuit breakers at other voltages, and generator field suppression for fault clearance.

Although these breakers can be made safe, the open contact cannot clearly be visually checked, and they are not used for safety clearance. Two disconnect switches and two extra sets of disconnect links have been provided, and these are especially useful in maintaining station service and starting (rectifier-inverter) supplies during generator or circuit breaker maintenance. They are marked with asterisks on Figure 2.

Transformers and Leads

Transformers inside the powerplant have given few problems; one generator transformer is being specially monitored for slightly higher than normal combustible gas. However, tightening Hazard Control regulations have emphasized the disadvantage of having transformers in the same enclosed area as other equipment. A separate chamber with independent ventilation and effective smoke barriers would appear to be highly desirable.

Delivery of the four 400 MVA single-phase 161/500 kV Intertie bank transformers was delayed by failure to withstand successfully their high voltage impulse tests. The problem was resolved by accepting reduced basic insulation level (BIL) for the 161-kV winding. The reduced BIL is regrettable, as the mountaintop, where they are located, is particularly vulnerable to the effect of lightning. The bank was placed in service in April 1979. One transformer failed in January 1985, in the high voltage winding, turn to turn at the neutral end. There was also core damage. The access road from the switchyard falls unevenly through 1 100 vertical feet in 3-1/4 miles (340 meters in 5-1/4 km). This increases the cost of transportation for repair and also subsequent road repairs, considerably.

Contrary to the original intention [2], the spare 161-kV oil-filled cable for the underground leads from the generator transformers to the overhead surface transmission lines was pulled into place ready for service. Two spare leads with transfer busses were provided to cover the twelve active leads. These have been used for short periods when small leaks have been noted at the lower pot-heads. However, the problem with leaks has been minor, in spite of a head of oil in excess of 1 100 ft (335 meters) acting on the lower section.

Switchyard

The 161-kV switchyard was initially energized in March 1977. The first of a series of explosive failures among free-standing porcelain pedestal-type 161-kV 6 000-5 Amp, current transformers (CTs) occurred in May 1978. These CTs are of the "inverted eye bolt" type, compared with the generally lower rated "hairpin" type. Two more such failures occurred that year, and all 42 of these devices were returned to the manufacturer in France, in rotation, for
rebuilding. At that time, it was considered that the problem had been due to poor connection between the semi-conducting layer and the wire mesh band of stages of capacitance grading in the main insulation. All CTs not destroyed were back in service or available at Raccoon Mountain by May 1980. Fortunately, CTs were available to be borrowed from other locations on the system.

Because failure of these CTs also implied the failure of protection of the circuits in which they were connected, additional backup protection was now provided. This was arranged by passing ground currents from the base of the pedestal CT through an additional ground fault CT. Upon detection of ground current, all necessary power circuit breakers are caused to trip to de-energize the faulted CT. Also, a breaker-failure timing relay is initiated; this trips after 12 cycles, if the ground fault is still present, to clear all connections feeding the circuit containing the faulted CT. This protection has functioned for each of the CT failures which have occurred since it was made active in 1983. Although it does not appear to have limited the force of the explosions, it does reduce fault clearing time.

An explosive failure of a rebuilt CT in service in May 1983 was the first of three in that year. Three more failed similarly in 1985. For a year, from September 1983, intensive studies were made with the EPRI Transient Monitoring Laboratory to determine possible causes of undue stress on the CTs at this mountaintop location. Perhaps the only significant discovery was that heavy high frequency currents flowing to ground at the capacitance taps of the CTs were recorded during circuit breaker disconnect operations. It was found that these currents could be somewhat reduced by selective sequential operation of the circuit breaker disconnect switches: By first closing that switch on the side of the circuit breaker (bus side) remote from the CT, the grading capacitors of the circuit breaker were utilized to initially energize the CT. Maximum recorded ground currents at the capacitance tap which had been as high as 1,750 amps (at 1.2 MHz) were reduced to 1,300 amps (max.) using this sequence. Although CTs were failing at other locations (including 500 kV CTs), the problem appeared worse at Raccoon Mountain. Those factors associated with the particular characteristics of Raccoon Mountain the mountaintop switchyard, and harmonics generated when using the rectifier-inverter under various conditions, were especially studied. No unusual system conditions, which might explain the CT failures, were detected.

Further work by TVA forces in 1985 involved the installation of equipment to measure and record (with alarms) insulation power factor and hydrogen-in-oil of CTs in service. Indications so far obtained are that this information can be used to avoid CT failures, as shown by the changes occurring on the record, Figure 6. Together with the record for CT 874C, which was removed for service, is also data for two, more healthy, CTs for comparison.

All the failures experienced at Raccoon Mountain had occurred in hot summer weather, and other information now available also implies that the problem is heat related. It was estimated that a change in insulation power factor from 1% to 10% results in a change of heat dissipation from 60W to 600W. Greater heating produced higher temperature and higher temperature more heating. The problem is thus regenerative. An interesting observation was that, while the change in power factor with temperature in a healthy CT could be predicted from tables, a more rapid rise of power factor than this could be associated with incipient failure.

A current transformer which was taken out of service with almost 13,000 ppm hydrogen apparently on the point of failure was dismantled for examination. The following signs of distress were observed: wrinkles in the paper and semi-conducting layers, evidence of high temperature indicated by the discoloration of copper braid, and a polymer coating on some paper. But, perhaps most significantly, no recognizable center of damage indicating a possible specific cause.

The problem with this type of CT has not, as noted, been limited to Raccoon Mountain but is present at a number of locations within TVA and has been felt generally in the industry. However, the effect at Raccoon Mountain was particularly severe, because 42 CTs of the same type, source, and age were in service together. Further, there were no 161-kV CTs of any other type in the yard.

Beside the CTs which actually failed, a number were taken out of service when rapidly rising hydrogen-in-oil was detected by sampling. (100 ppm is a signal for more intense sampling.) More recently, rising insulation power factor, when monitored continuously, has proven a more suitable guide. Only 24 of the original 42 CTs are now in service. Lacking a specific basic explanation for the trouble and because replacements were now urgently needed, it was decided to replace all the oil-filled CTs with new ones of the sulfur hexafluoride (SF-6) gas insulated type. These are described as explosion proof because they utilize fibre-glass cored porcelain. SF-6 insulation is considered less likely to produce an explosive condition. Installation should begin in the fall of 1986.

In the intervening summer of 1986, by coincidence, 24 information channels are available to record conditions in the 42 CTs in service. The newer, replacement CTs considered to be at lower risk, will not be covered at first, but the system is flexible enough to allow changes. Based on the (limited) evidence gathered in the late summer of 1985, it was decided for 1986 to utilize all available channels for Power Factor monitoring, set the alarm level at 5%, and visually monitor twice a day, plotting the results to give indication of any sudden upturn.

![Fig. 6. Current Transformer Insulation Record](image-url)
Due to the scatter of flying porcelain on failure, it was considered necessary to deenergize five bays in the switchyard for maintenance work— even for taking oil samples. This has severely limited regular circuit breaker maintenance so that, after eight years, only about half the breakers are inspected. Inspections so far have shown need for correction of the breaker elements, but none has yet shown signs of impending catastrophe. Our experience has been that these air blast breakers are best carried away from the switchyard to a protected area for servicing, and that inclusions, such as a spare breaker, or even one phase of a breaker, with the original purchase, would have been advantageous.

Control

The plant and switchyard were originally intended to be operated by remote supervisory control from an Area Dispatch and Control Center (ADCC) located about 10 miles (16 kilometers) away. The switchyard has always functioned in this manner, but it was quickly realized during the startup process that distant monitoring would not be adequate for the plant itself. These units are sensitive to load and have limited bands of satisfactory operation. The general monitoring of a plant of this nature, particularly the possibility of flooding the underground powerplant, calls for regular attention. Operation continues to be from the in-plant "remote" central control point adjacent to the generator room.

The complicated interlocking control systems provided at the plant were not installed. Fault and have been generally trouble-free in operation. Only minor additional constraints and improvements have been added, such as wicket gate closure on movement of the spherical valve from the fully open position, and the position of this valve is now indicated at the control point.

Vibration. was now continuously indicated and recorded at the plant control point. It was felt desirable to have continuous indication of unit bearing temperatures and to bring them to the central control point; multipoint (periodic) recorders (with alarm) are retained at the governor cabinets near each unit. All these temperatures are monitored by resistance temperature detectors. The control point indicators now also provide "trip" and "alarm" for bearing temperatures. The original gas bulb detectors with mercury in glass temperature switches behaved unpredictably, particularly during thunderstorms. It is thought possible that lightning surges caused vibration at the generator which disturbed the mercury.

In connection with revisions being made at the ADCC, alarm displays in the plant will shortly be made more comprehensive as the plant system becomes self-contained. Additionally, alarms from the switchyard will be transmitted down to the power plant.

Black Start

"Black" starting capability was incorporated in the plant design, and so direct current driven high pressure thrust bearing lift oil and turbine bearing lubricating oil pumps were provided to enable the units to be started. However, many of the auxiliary supplies, oil pumps, water pumps, etc., are not available until the unit is started. This requires a number of the protective interlocks to be defeated by the control scheme under these circumstances and the functional checkout was quite complicated. The additional complexity of control, with seldom used facilities, exposes the control system to possible inadvertent and unrecognized breakdown of its integrity in the course of minor modifications or with time. Regular testing is time consuming. Black starting, achieved by providing extra redundant diesel generating capacity for auxiliary supplies, might have been more realistically manageable over the long term life of the plant.

Mechanical Equipment

As might be expected, problems have not been confined to the electrical equipment. Only a brief survey of mechanical experience is made here.

It was quickly discovered that unacceptably rapid cavitation damage was affecting the pump-turbine runners in service. Model indications, based on the breakdown of hydraulic performance (efficiency) as suction pressure (but not net head) was reduced, had indicated adequate cavitation resistance for the site setting. This was, at that time, generally accepted as a sufficient criterion for cavitation resistance. But it was subsequently shown in the model that bubbles of cavitation could be observed in clear water at somewhat higher suction pressure than that at which hydraulic performance broke down. This testing was now done to develop a blade design more appropriately resistant to cavitation. The runner blades were then reshaped, in effect, replacing the last four inches (1000 mm) or so of the trailing edge of each with a differently shaped attachment. This was a major undertaking. The work on the runners was done in place, without dismantling. Work was interrupted for the summer and winter peak load seasons, but was nevertheless completed in a little over a year.

Maintenance forces have since made templates from the blades, using those blades with best observed cavitation performance in service as guides. This enables comparison with an independent standard in case blade profile should be lost through heat distortion, which can occur during heavy welding, or by progressive loss of profile in the course of successive weld repairs to cavitation damage over the years. It has also been possible to make minor adjustments to the profiles of the more cavitation-prone blades, bringing them into closer conformity with those found to be more resistant. Observations showed that the weld repairs on the runners have been extended over the years from 2000 hours operation to 4000 hours, improving availability.

Four failures of the lower rotating runner seal rings of the pump-turbines have occurred in these units. These rings control the leakage of water past the turbine runner and thus influence efficiency. They are often known as "wearing rings" in pump practice. Mounted at the extremity of the unsupported portion of the turbine-generator shaft system, they are subject to both eddy current and shock loads and shaft deflection occurs. This happens particularly at the point of priming of the pump on startup. Not only is it possible for the seals to be damaged by rubbing, but a temperature rise to only 100°C can relieve the shrink fit which holds the seal ring on the runner. The turbine runners are unwatered by compressed air for starting in the pumping direction, because, in water, the power requirements are almost impossible to meet at sub-synchronous speed. Very severe heat dissipation problems can be developed in the trapped water. When the unit is synchronized to line, the air is released. Then when the pump is sufficiently primed, the wicket gates, controlling the flow of water, are opened. The moment of priming is determined, for the purpose of control, by a switch actuated by the pressure under the headcover of the
pump turbine. Wicket gate opening is then initiated, allowing the water to be pumped to the reservoir.

Figure 7 shows that peak vibration experienced during the transition can be related to the pressure switch setting. It is also interesting to note that unit 3, which had its pressure switch least advantageously set initially, suffered all except one of these noted failures. Repairs are expensive because they require complete dismantling of the unit shaft system.

Based upon the experience of others, it appears that the choice of stainless steel wicket gates was fully justified. It is interesting to note that stainless steel or other rust-free components could apparently have been advantageously incorporated at a number of points. Teflon bushings, adjacent to plain carbon steel in the presence of moisture, were worn excessively by corrosion products. This allowed relative motion in the linkages controlling the wicket gates, and serious vibration of the gates developed. This has been controlled by placing rust-free materials adjacent to the Teflon. In the 10 ft. (3.05 meter) diameter spherical valves which shut off water upstream of the pump-turbines, free flexure of the moving seals has been restricted by corrosion products and water related debris. This lessens the chance of making a tight seal. Incorporation of even limited amounts of rust-free surfaces in critical areas appears to help considerably by controlling the causes of (local) binding.

Conclusions

The innovations incorporated in the design of the plant, stretching capacity, and other changes have led to an extended commissioning period, so that improvements which can materially contribute to long-term plant availability are still becoming apparent.

Direct water cooling of hydroelectric generator windings has proven workable, though there are some inherent differences in detail from the factors affecting this technique in steam plants. Reliability would appear to be somewhat less than that of more conventional generator windings in which the conductor is more thoroughly encapsulated, in the end turns as well as through the slots. Loss of availability, as well as repair costs, detract partially from the economic advantages shown by Mock [2]. There may be other advantages, due to reduced physical size, which have not been mentioned. Windage losses for instance can be expected to be reduced, and the effects of expansion and vibration can be better controlled. It appears that the Raccoon Mountain stator windings have perhaps stayed in service longer without retightening the slot wedges, than has been experienced elsewhere in comparable cases.

The reversible pump-turbine, as well as being subject to heavy transients at the time of priming of the pump, also embodies a compromise at the low pressure (turbine-leaving) blade edges in a conflict between the desire for pump efficiency and smooth running in the turbine direction. Thus, the reversible pump-turbine cannot be expected to run as smoothly in the generate direction as a conventional Francis turbine. Some of the onus for achieving satisfactory operation falls on the support provided by the generator shaft. It would appear profitable when purchasing future units of this type, to analyze and clearly define responsibility for the dynamic performance of the total system.

Problems in the switchyard are not peculiar to large pumped-storage hydro, but have clearly taken resources and imposed constraints on other areas needing attention. The experience does indicate the need for serious consideration of the provision of spare parts, even major components, when purchasing equipment for projects of this nature.

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References


