Internal Leakage Study
Winyah Generating Station Unit #3

Leif M. E. Svensen, P.E.
Santee Cooper
One Riverwood Drive
Moncks Corner, SC 29461
(843) 761-8000

Introduction

Winyah Generation Station is located in Georgetown South Carolina. It contains four coal fired steam-generating units. Winyah Generating Station Unit #3 is a 300 gross MW output coal fired unit with a General Electric (GE) steam turbine and a Riley turbo fired boiler. In the spring of 2001, GE completed turbine warranty maintenance. During this time GE did not get new N-2 packing on site, therefore the station refurbished and replaced the old packing.

The earliest we could perform a temperature variation test was in September of 2001. This test indicated an internal leakage flow rate of 14.4 percent of hot reheat flow. In the spring of 2002, the “apparent” intermediate pressure (IP) turbine efficiency increased by over one percent. During the investigation we noticed other indications pointing toward a possible internal leakage problem, the changes are; hot reheat temperature, superheat spray, steam flow per MW output, thrust bearing position, hot reheat pressure and a decrease in first stage pressure.

Analysis

The increase in “apparent” IP turbine efficiency is the main reason that research of this event started. The “apparent” IP turbine efficiency is the measured efficiency without correcting for actual internal leakage rate of the turbine. As the internal leakage flow from the high pressure (HP) to IP turbine increases, the colder steam entering the IP bowl from the first stage of the HP turbine reduces the crossover temperature. The reduction in crossover temperature causes a change in the enthalpy thus causing the IP turbine efficiency to “appear” to increase. The other reason for this “apparent” increase is that the inlet conditions do not reflect the change as they are before the IP bowl. Therefore, by not changing the bowl conditions to account for the current internal leakage rate as a percent of hot reheat flow, the IP section efficiency rises. We continued to track this “apparent” IP efficiency change throughout June and July. During this period, the “apparent” IP efficiency gradually increased (See figure 1).

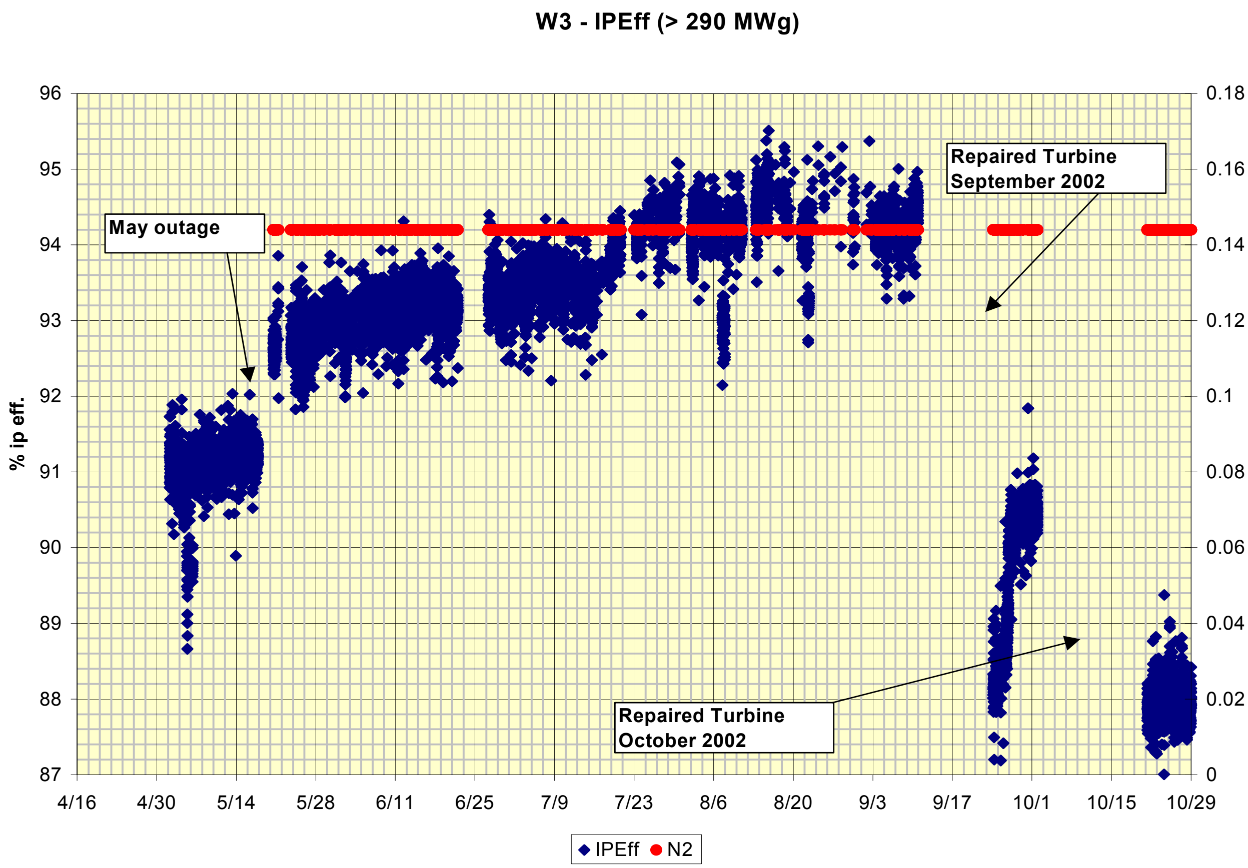

Figure 1

Another indication of a leakage problem is the increased need to spray superheat temperature to lower and control the reheat temperature. Winyah Unit #3 does not have the capability to spray reheat temperature. To control hot reheat temperature the unit operator has two options: to reduce superheat temperature by attemporator spraying or move the back-pass dampers. The station personnel could move the back-pass dampers only so far, so they needed to spray the superheat temperature down to 940ºF from the design of 1000ºF. This is a symptom of increasing internal leakage rates because as the leakage increases, less steam will leave the HP turbine and passing through the reheater. With the reheat surface supplying the same amount of heat, the reheat outlet temperature will increase. The PEPSE® model confirmed this cycle change. We used a PEPSE® model at the design heat balance to obtain the amount of heat the reheater adds to the cycle. After the heat added to the reheat steam is calculated, it is then used to fix the heat input from the reheater in the next set of runs. The internal leakage flow is then varied. I used the sensitivity study option in PEPSE® to change the leakage rate in increments of 5,000 lbs./hr. The results indicated a 10ºF rise in hot reheat temperature for every flow change equal to 2.5 percent of hot reheat steam flow. Therefore, the increase in hot reheat temperature can indicate higher internal leakage rates.

During the same period, the station personnel noticed that the thrust bearing position was changing and the turbine was gradually moving toward the generator. This change indicates more steam flow going through the IP turbine and less steam flow through the HP turbine. Another change seen was in the first stage pressure. This pressure dropped indicating an opening of the downstream turbine area. This opening can either be due to wear on the turbine blades or increased packing leakage. There was also an increase in the steam flow (lbs./hr) to MW output ratio. This change can be a result of higher internal leakage. The increase in hot reheat pressure also showed up when investigating the change in IP turbine efficiency. This change indicates greater steam flow going through the IP turbine. During the same period, the upper and lower IP turbine bowl shell metal temperatures developed a split of greater that 100ºF with the upper bowl being the lower of these to readings. This indicated that the lower temperature leakage steam is cooling the upper bowl shell metal temperature lower than that of the lower bowl metal temperature. The hot reheat enters the bottom of the turbine bowl, which can easily direct the internal leakage to the top half of the IP turbine bowl. Due to the higher steam temperature entering at this location it caused the lower bowl shell metal temperature to be higher.

On July 16, 2002, Performance Services conducted a valve wide-open test, using the online system (OLS) to collect data. We used the data from this test and a PEPSE® model of the cycle, to estimate the amount of internal leakage. To estimate this leakage rate the as tested steam flow and condenser pressure were entered in a design model. Using these inputs the model calculated the heat input from the reheater at 1000ºF outlet temperature. The model was then setup to use the calculated reheater heat input as a fixed amount along with the tested superheat temperature and superheat spray flow amount. The model was run again with these changes using a control that varies the model's N-2 leakage rate until the tested hot reheat temperature was reached. The result was a calculated leakage rate that equaled 20 percent of the hot reheat steam flow. This gave us enough information to estimate the costs of an internal leakage change from the 14.4 percent calculated in September 2001 by testing to the current estimated 20 percent of hot reheat flow. Consequently, we determined this change is worth about $820,000 per year. To confirm these results and this way of estimating the internal leakage, we conducted a temperature variation test in early August to determine the actual internal leakage rate. The test result was a leakage rate of 22 percent of hot reheat steam flow. This shows that you can use PEPSE® under certain conditions to determine the internal leakage rate of a steam turbine with reasonable results.

Further investigation was required to determine the cause of the leakage steam. In late August we conducted a N-2 packing blowdown test and measured the steam flow going through to the IP turbine along this shaft. Based on this test we determined that the packing was leaking between 5 and 6 percent of hot reheat flow or was about one quarter of the total leakage flow. The two main remaining areas at that time for a steam leak to occur are through the snout rings and/or horizontal joint. Based on the previous turbine maintenance report, the snout rings were the areas most likely to have the larger of the two leaks.

This information caused the station personnel to inspect the unit immediately when a shut down occurred due to a transformer fire in the switchyard. The inspection plan was to remove one intercept valve and get inside to see the inner shell. While the valve was being removed, a 3.5-inch diameter turbine joint nut was found at the bottom of the valve body. After this find, the turbine was immediately removed from service and the outer shell was removed. We found that two 6-inch nuts were totally off the studs on the left side shell studs. Two other nuts on the same side were more than one inch from the shell. On the right turbine shell side, all of the 6-inch nuts were loose. When the horizontal joint was measured, it was found 90 mils open at the end closest to the inlet of the IP turbine, therefore, the majority of the steam leak. The left side cooling holes were found plugged, which is one reason the inner shell nuts could have become untorqued. Without the cooling holes it is theorized that this caused the studs to over stretch, this loosened the nuts. The repairs included replacing the damaged studs, cleaning out the cooling holes, and reassembling the unit.

Performance Services tracked the unit after it came back from its outage. After the outage, an initial OLS performance test indicated an improvement of about 290 Btu/kWhr in heat rate. We continued to track the IP section efficiency, turbine pressures, bowl metal temperatures, and thrust bearing position. After about a week the apparent IP efficiency step changed from 88.5% to 90%. The first stage pressure dropped suddenly and the thrust bearing position moved to where it was before the September 2002 turbine repair. These readings got progressively worse as time passed. We initiated recommendation to open the turbine again. The turbine was opened and we found that the inner shell nuts had untorqued again. The second repair replaced all inner shell turbine studs with new ones, some of which were over sized from 6 to 6.5 inches to insure they would stay put. Data was gathered to see the changes that occurred as a result of this outage. One improvement was a gain of 0.7% in HP Efficiency can be attributed to new valve discs, repair to second stage, and closing of the horizontal joint during this outage. After the second outage the leakage rate was able to be tested and was now 4.2 percent hot reheat flow. This rate is the lowest of all GE turbines at Winyah Station.

Conclusion

I used PEPSE® to do two “mini” studies for this investigation. First, I used PEPSE® to determine that a change in internal leakage rate will change the hot reheat temperature. In this case, I fixed the heat the reheater supplies to the model and varied the internal leakage. Second, I used PEPSE® to get an estimate of the internal leakage rate. Here I took some essential test data and used a design type model to match the tested hot reheat temperature. In doing this I was able use the model to get a leakage estimate to see if the more accurate temperature variation test needed to be conducted. These turbine changes occurred during the summertime, and the unit involved stayed at full output almost continuously. This unit cannot complete a temperature variation test at full output. Using the PEPSE® results, we were able to schedule the two leakage tests, at reduced output, with little resistance from dispatch and management due to the importance associated with the magnitude of the daily losses. Using the actual internal leakage rates, we calculated that the cost of operating this way would be over $1,000,000 per year. This cost only includes the difference between the 14.4 percent and 22 percent leakage rates. The breakdown in costs are internal leakage rate improvement $433,000, superheat temperature improvement $437,000, and HP efficiency improvement $130,000. Experience has shown that Winyah Unit #3 is capable of leakage rates lower than 5 percent of hot reheat steam flow - thus higher savings. Additional savings by improving the internal leakage rate to less than 5 percent of reheat flow is estimated to be about $619,000 per year.

References

I used the following references during the course of the analysis and in preparation of this paper.

1 - PEPSE computer code, Scientech Inc, PO box 50736, Idaho Falls, Idaho, Version 62H
2 - PEPSE manual: volumes I, II, III, IV, Scientech Inc, PO box 50736, Idaho Falls, Idaho, Version 62H
3 - K.C. Cotton, “Evaluating and Improving Steam Turbine Performance”, Published by Cotton Fact Inc., Rexford NY, ©1993