LOAD RAMP RATE
and STABILITY OPTIMIZATION

Improving the stability and ramp rate capability of established power plant units is a challenge which presents itself more and more frequently as we enter the nineties. Many 10 to 20 year old units which were originally designed for baseload operation now idle at minimum load at night, and rapidly swing to high load for the day before quickly returning to the nightly minimum.

A sluggish unit which cannot keep up with power pool demands is often subject to peer pressure, as someone else in the pool has to make up the difference. Often the cure is well within the capabilities of existing equipment, if only it were maintained and tuned properly.

This paper addresses controls equipment only, and assumes that mechanical preparation of the boiler and turbine have been addressed. Such was the case at Gerald Gentleman.

THE GERALD GENTLEMAN STATION

The Gerald Gentleman Station consists of two 680-MW units. Unit 1 has a BBC turbine-generator with a Foster Wheeler boiler. Unit 2 has a GE turbine-generator with a B&W compartmented windbox-type boiler. Each unit is controlled by an L&N DEB-300 control system. Both units are now approximately 10 years old.

Unit 2 was addressed first, having a ramp rate capability limited to 3 MW/min., or about ½ percent per minute. Operations staff preferred to sustain low loads on three of the eight pulverizers, which meant a minimum load of about 210 MW. This was in contrast to the daily load cycle, which zoomed from 180 MW at night to over 500 MW each day, per unit.

RAMP RATE IMPROVEMENT - A METHODICAL APPROACH

this paper focuses on ramp rate improvement of one particular unit. But the technique used to accomplish such improvement can be applied to make any controls improvement project a success. A proper approach to ramp rate improvement requires a thorough understanding of the existing control equipment and the equipment to be controlled. The existing controls configuration must be understood, including why and how it works and/or does not work.

Optimization of controls usually means making each loop as fast as possible, without being too fast. This fast/too-fast threshold is a function of total closed-loop dynamics, which includes equipment response time and other characteristics.

Thus, some version of the following procedure should be followed, as was done at Gerald Gentleman.

1. Understand existing controls. Poor control is not necessarily caused by poor SAMA logic configuration. The existing system may be configured nicely, but improperly tuned or in a state of disrepair. Study the logic until it is understood. A call to the original design engineer, equipment manufacturer or control system manufacturer will often shed light on the original intent.

   The same approach should be taken for system revisions. A revision is valuable because it indicates a problem existed and that someone was interested enough to design a correction. A conversation with the "revisor" may be useful, even if the revision is incorrect.

   No system should be "improved" until it is first understood.

2. Understand the controlled equipment. We encourage detailed unit testing and evaluation before any changes are made. Try to determine time constants. Understand which part of the process is affected by which other parts.

   Example: At Gerald Gentleman the radiant superheater was found to be primarily affected by firing rate, while convective passes were primarily affected by air flow. This may not be surprising, but the original control configuration did not reflect it.

   One point should be noted about both testing and tuning. It is recommended to use a very flexible 6-pen recorder for this type of work. It is very difficult to obtain the necessary data from multiple recorders or from recorders with overlapping pens. Also, if the system is a distributed control system (DCS), be sure the sample intervals are small enough to provide the necessary tuning resolution. Most are not, in spite of the DCS manufacturers' claims.

3. Repair. Of particular importance here are final drive elements, such as dampers, valves and associated control drives. It is unfair to ask a control system to perform, while inputting false information about drive unit or damper position. The methods of testing may vary, but should be similar to the following:
   a. Tag out all related equipment including the drive and damper, and sign in to the open vessel log where appropriate.

   b. Place the selected damper in manual.

   c. Place one instrument technician in the control equipment room with a digital volt meter reading the position feedback voltage; two persons at the control drive to determine drive and driven-arm positions and to observe possible malfunctions or

operating problems; and one person in the control room to read indicated damper position.

    d. Have the control room operator manually stroke the drive open and fully closed until the drive stops itself (rather than the operator assuming full closed and releasing the button).

    e. Record indicated drive arm and driven arm positions in degrees, and the position feedback voltage.

    f. Have the control room operator stroke the damper to an indicated 20 percent open. At no time allow the damper to be reversed, so that any looseness in linkage and gearing will be maintained all to the same side of the damper position. Thus, if the control room operator happens to release the button and stop at 22 percent open, then take data at that point.

    g. Repeat step f. Above for 40 percent, 60 percent, 80 percent and 100 percent open.

    h. Repeat steps f. And g. In reverse order to 0 percent open.

    I. When possible, pull the linkage pin to determine if either the drive or damper is bale to travel further closed.

    j. At full closed, a visual internal inspection of the damper position will verify the actual closed position of the damper.

    k. An internal inspection of the damper will verify the condition of bearings, seals, blades, etc.

4. Start at the bottom. Just as in tuning, reconfiguration and retuning is best done by addressing final drive elements first and working toward the top of the loop. Other control loops may be depending upon upper portions of the loop in question for input, and thus will be affected by radical changes.

5. Don't hold manufacturer's recommendations sacred. The equipment manufacturer's interests are usually different than the utility's. Inadequate ramp rate ability or load stability reports are less frequent than are equipment failure reports or high maintenance reports. When they are reported, the controls usually receive the blame. Thus, the boiler manufacturer's control recommendations are usually far too conservative because his goal is simply a reliable unit. A rapid ramp rate for example, more closely approaches thermal stress limits of the boiler drum and tubing, and his recommendations will stay far from those limits. The utility, however, needs a reliable unit that performs.

6. Be innovative. Once the system and equipment are understood, innovation can be used in controls configuration. Adding or subtracting features is encouraged if testing and research prove the validity of their application.

   Example: On the Gerald Gentleman unit, with variable speed boiler feed pumps, steam temperature was found to be partly a function of drum level. Further investigation showed a superheat spray taken directly off of the pump discharge. Thus, as the feed pumps modulated speed to control drum level, the feedwater pressure also modulated, which changed superheat spray flow without moving the spray valve at all. Subsequently, feed forwards were tried, based on feedwater pressure and on valve d/p.

7. Recognize "hidden" deficiencies as they surface. Reconfiguration is often a reiterative process. As major control problems begin to clear up, new control problems may appear in the process. While this may actually be the case, in most instances the new problem has been there all the time, masked by the presence of other larger problems. Correcting all of them may require two or three iterations.

8. Consider a DCS. Determine if and when controls are to be replaced with a new microprocessor-based system. Planning a controls replacement may affect a ramp rate improvement schedule, since both tuning and configuration are much easier and safer with a DCS than with a hard-wired analog system.

The following briefly discusses the control revisions at Gerald Gentleman.

THE FRONT END

Both units at the Gerald Gentleman Station were designed for control in either constant pressure or sliding pressure mode. In practice, however, automatic sliding pressure had never worked. Operators were forced into a manual sliding pressure mode in which the operator monitored turbine valve position and manually changed throttle pressure set point accordingly.

The District actually preferred sliding pressure control because of its efficiency and better steam temperature control. Automatic operation was unsuitable, however, because the unit would go into a swing which increased with each oscillation.
A review of the control system revealed extreme complexity, much more so than normal. In addition to complexity, other problems were found:

- No direct link between load and expected throttle pressure. The set point was always a calculated value.
- A noisy load reference signal.
- A variable frequency pulse from the dispatcher for demand changes.
- An unstable zone in the turbine throttle valve position.
- Excessive filtering in the generation feedback signal to the dispatcher.

As engineers tried to simplify the front-end, they found many other parts of the control system affected. In the end, only simple modifications to the existing complicated system could be implemented.

The original L&N system compared control valve set point to a calculated version of valve position, scaled the error according to throttle pressure set point, and passed that signal through a "variable throttle pressure set point controller." Thus, unit load had no direct input into the system.

The new system makes the same comparison and the same scaling, but then runs through a lag circuit before summing with a characterized feed forward from unit load. This summed signal is then lagged again, becomes throttle pressure set point, and is compared to working throttle pressure set point before going to the controller. Thus, the major difference is that the new system programs throttle pressure based upon unit load, and trims based upon valve position.

One additional feature is a manual set point for valve post. This feature allows the operator to optimize operations based upon performance results an to avoid unstable valve points.

In the sliding pressure mode, valve position was made the throttle pressure set point. Set point was then given to the operator and made variable. The variable frequency pulse load set point was replace by an analog set point, and the noisy load reference signal (first stage pressure) was replaced by generated megawatts.

Upon looking into the DEB/300 front-end, a difference between the generated megawatt signal and the generated megawatt feedback signal to the dispatcher was noticed. The L&N system wiring drawings indicated a 200-mf capacitor was filtering the feedback signal and also creating a substantial time delay. The R-C time constant was 4 seconds. However, the dispatcher could only send pulses to the plant once every 4 seconds or more.

Thus, the dispatcher was not receiving proper response from the plant after sending out a pulse. The unit would respond quickly but not tell the dispatcher for 4 seconds, so the dispatcher would pulse again. The unit would respond again and finally be generating more that the dispatcher wanted, so he would then pulse down. This process set up a continuous cycle.

The 200-mf capacitor was replaced with a 0.1-mf capacitor which eliminated the oscillations, but otherwise did not adequately filter the noise. A 1-mf capacitor proved to be sufficient.

FUEL FLOW

The fuel flow controls were slow, and required considerable refinement. The controls were tuned sluggishly because the hot, tempering and rating dampers were slow to react, and because the fuel control servo itself was very slow. Fuel control work included:

- Repairing and tightening all dampers, drives and linkages.
- Increasing servo speed by a factor of 100.
- Tying manual feeder speed to the former slower servo speed.
- Conducting clean air tests.
- Recharacterizing the pulverizer PA/fuel ratio.

This unit has B&W MPS-89 pulverizers, with seven burners per pulverizer for 56 burners total. Full load is obtained on seven pulverizers, however, which means each burner sustains about 14 megawatt with 19-inch coal conduit. This 19 inches is much too large, even with Western fuel. Consequently, the PA/fuel characterization curve reached minimum line velocity in the normal pulverizer operating range. As the pulverizer load passes through this inflection point, the overall loop gain changes dramatically. With a DCS, the controller tuning parameters could be automatically adjusted accordingly. With a hard-wired analog system, though, this is not practical.

The appropriate solution involved a compromise between good pulverizer response (steep curve) and pulverizer stability.

AIRFLOW

This unit, being a compartmented windbox design, has 16 secondary air flow dampers and 8 primary air flow dampers. None were provided with a controller. The control system manufacturer still insists they are unnecessary, although we found that they are.

Thus, secondary air control revisions consisted of:

- Adding secondary air damper controllers.
- Detailed testing and recalibration of air flow transmitters.
- Tuning.

FURNACE DRAFT

Furnace draft controls were left alone, except for tuning and one simple, but significant, revision.

The three draft transmitters signals were each passed through a passive filter to reduce extreme peaks. The problem here is that passive filters add a time delay, and this is a loop requiring fast response.

The passive filters were replaced with active filters which subtract out the peaks without a delay.

FEEDWATER

Feedwater control revisions centered primarily around balancing boiler feed pump speed and response. A revised control circuit provided speed balancing. Balanced response, however, seemed to be a problem unique to the boiler feed pump turbine governor itself. Both corrections were routine.

STEAM TEMPERATURE

Steam temperature control was an extensively revised system, primarily in the superheat area. This was a case of the loop being too simple. The District had experimented with a variety of feed forwards, but none seemed to work satisfactorily.

At the time this unit was placed into service, B&W accomplished superheat sprays in two steps. The first section was allowed to spray as much as required until outlet temperature approached saturation, at which point the second set of sprays would complete the task. The boiler manufacturer had advised that the correct feed forward may be either air flow or firing rate, but not both.

The District had already revised the system so that the first section did not care about saturation, but instead tried to maintain a constant 760°F outlet. The second section then tried to hold the 760°F inlet steam to 1005°F outlet.

As we evaluated the District's revision and B&W's recommendations, it became apparent that what the District had actually done was isolate the two sections, almost as if they were in two separate boilers. The first section was in a boiler with a constant 760°F outlet. The second section was in a boiler supplied with 760°F steam.

We also noted that the first section was primarily radiant, and thus primarily affected by firing rate. The second section, however, was primarily convective, and thus primarily affected by air (combustion gas) flow.

As a result, a firing rate feed forward was installed for the first section and an air flow feed forward installed for the second. Additional temperature inputs were also installed.

The reheat controls intended for this boiler are B&W's "bias firing." A telephone survey found no one able to use the bias firing technique as designed. Most units implement manual bias firing as they exercise their choice of pulverizers to place in service. B&W's bias firing, however, involves itself with burner stoichiometry, and does not seem to provide the intended result. The District opted to remove bias firing and implement a very conventional reheat steam temperature control system.

RESULTS

The results are encouraging. Through considerable performance testing we found the unit capable of 25 MW/min. This limit decreases as maximum or minimum pulverizer capability is approached, since primary air flow leads fuel flow on the load ramps. Very short load changes of about 10 MW can be handled much more rapidly. One test ran the unit up 10 MW at 75 MW/min. Dispatch has set the maximum for this unit at 15 MW/min. Prior to this work it was 3 MW/min. Low load in automatic is now about 185 MW.

As mentioned previously, elimination of major operational problems allows lesser problems to surface. In this case, relatively poor burner performance is limiting further improvements in ramp rate. Exceeding 25 MW/min significantly bumps drum level, as combustibles which have escaped the burner front are disturbed. For the same reason, superheat sprays are excessive and furnace draft is noisy.

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