Operating Concept for a 240-MW Combined Cycle Intermediate Peaking Plant

P. A. Berman

This paper describes the design of a combined cycle power plant for intermediate peaking with particular reference to design features resulting in simplified control and operation.
Operating Concept for a 240-MW Combined Cycle Intermediate Peaking Plant

P. A. Berman

PLANT DESCRIPTION

The combined cycle power plant presented in this paper consists of two 5000 gas turbines, each exhausting into its own steam generator. The output from both steam generators is fed into a single cylinder steam turbine designed with axial exhaust and generator drive from the high-pressure end to accommodate grade level installation. The condensate is passed through a single deaeterating feedwater heater which receives steam from both turbine extraction and a low-pressure steam generating coil at the exit of the steam generator. The cycle diagram is shown in Fig. 1 and the plant arrangement in Fig. 2.

In the design of the overall plant, the prime objective was to obtain a relatively large block of highly efficient power that could be installed in a minimum of time and cost. Wherever possible, the plant is designed for simplicity of operation. Reliability is recognized to be an extremely important factor in a power plant of this type, since the plant must be capable of going on line with minimum operating attendance. Therefore, the basic design is targeted to allow plant operation at a load of approximately 50 percent with any single component not operable. A number of features are included in the plant to minimize control system complexity.

1. The feed heating system was selected to allow for a single stage of feedwater heating while still retaining a good level of operating efficiency.
2. The system was designed so that bypass stacks and dampers would not be required while retaining operating flexibility.
3. Design features were included to allow self-regulation of steam temperature and pressure simplifying the control concept.

FEED HEATER SELECTION

In a typical waste heat steam generator, shown schematically in Fig. 3, the point of closest approach between the gas and the liquid occurs at the high-pressure boiler exit where

---

the gases have been cooled down while giving up heat to a constant temperature zone (saturation temperature). This sometimes is referred to as the pinch point, which basically establishes the energy available in the economizer and low-pressure portions of the steam cycle. Some of this heat can be recovered through the use of a low-pressure boiler coil and the utilization of this low-pressure steam for feed heating.

To minimize overall plant cost, the steam turbine selected should be maximum end loaded. The turbine selected to best match the gas turbines was a 28 1/2-in. single flow end. Once the end is selected, any increase in throttle steam flow resulting from extraction for feed heating will increase the power output from the plant and reduce its capital cost. However, as more steam is extracted for feed heating, less steam can be utilized for feed heating from the low-pressure steam generating coil, and, therefore, an increase in steam extraction results in a decrease in plant efficiency. This characteristic is shown in Fig. 4 which displays the variation in heat rate and power as we move from 100 percent extraction feed heating to 100 percent low-pressure steam generator feed heating. Parameters of steam turbine extraction pressure or extraction stage are displayed and the trade-off between power and efficiency can be seen. It is apparent from this figure that as the extraction pressure is increased, there is a marked decrease in overall plant efficiency. Another important point that must be considered in selecting the feedwater cycle is that as the steam turbine goes to part load, the pressure at the extraction point will decrease. This decrease is almost in direct proportion to the load on the steam turbine. If the deaerating heater is designed to operate at say 50 lb, it would normally be at 25 lb at half load and below atmospheric pressure at lesser loads. Since this heater must always be above atmospheric pressure to vent the non-condensed steam,
densable gases properly, provision would have to be made to change over to a second source of steam at part load. The alternative to this is to start cut at a sufficiently high pressure in the heater so that in the normal operating load range, this transition is not required. From Fig. 4 it can be seen that as the pressure level is increased, plant efficiency decreases, and, therefore, to compensate where the low-pressure coil is not used as a steam source, the desalting heater will normally be placed at a fairly high-pressure level and an additional stage of closed feed heating will be added at a lower pressure level. The use of a low-pressure steam generator provides a very unique solution to the two-stage feed heating alternative.

At part load the low-pressure coil starts to generate an increased amount of steam, and, therefore, if non-return valves are used in the extraction line and the design point is properly selected, the feed heater pressure will not go below atmospheric pressure prior to the point where the low-pressure coil is generating sufficient steam to supply the entire feed heating requirement. When the proper balance is made, the heater pressure will drop slightly and then start to rise as the steam generation rate in the low-pressure element increases. This characteristic pressure swing is shown in Fig. 5. As a result of the careful combination of the low-pressure coil and selection of the steam turbine extraction point, high efficiency can be maintained over the load range with a self-regulating single stage of feedwater heating.

STEAM TEMPERATURE CONTROL WITH AMBIENT

For lowest first cost, the steam turbine should be at its maximum end loading at the plant rating point. At low ambient temperatures, with a fixed geometry gas turbine, the gas turbine airflow will be increased because of higher air density. There will be a tendency to increase steam flow if the supplementary firing rate is maintained. This, of course, would exceed the design flow limits of the steam turbine, and the supplementary firing must be reduced to hold constant steam flow at lower ambient. The reduced supplementary firing will result in decreasing steam temperatures and increasing exhaust moisture levels. There are a number of ways to prevent the increased moisture condition, some of which include:

1. The use of variable inlet guide vanes on the gas turbine. This will compensate for increased air density of low ambients by reducing the airflow and allowing efficiency levels to be maintained. However, one of the advantages associated with the gas turbine of increased power at lower ambition is lessened.

2. A bypass stack can be used between the gas turbine and the steam generator to allow a portion of the gas flow to bypass the steam generator. This will maintain steam conditions; however, it results in reduced plant efficiency levels.

3. A superheater bypass can be provided in which the superheater is oversized at the design point and a portion of the steam is bypassed to limit superheat temperature. This bypass is reduced as ambient decreases, thereby affecting an increase in the size of the superheater tube surface and allowing steam temperature to be maintained. This has little effect on capability and efficiency; however, the cost of the superheater is to be increased. A similar effect can be obtained through the use of an attemperator.

The selection of the method to provide proper steam conditions with ambient must be made on overall economic evaluation. It appears at this time that a combination of variable inlet guide vanes on the gas turbine and superheater bypass will provide the best economics to allow the maintenance of proper steam conditions in
the steam turbine and the benefits of low ambient operation for the gas turbine.

STEAM PRESSURE CONTROL

At a given ambient, the plant is operated with valves wide open and floating pressure. This provides for an improvement in the moisture level at the steam turbine exit as the unit moves to lower load and, in addition, greatly simplifies the control system, since fuel flow is associated with load requirements and no attempt is made to control pressure in the steam system.

BYPASS STACKS

Many combined cycle steam plants conceived today incorporate a bypass stack between the gas turbine and the steam generator. The main functions of the system is to allow operation of the gas turbine prior to steam turbine warm-up, to allow start-up of the gas turbines in low ambient without freezing steam generator tubes, to provide for low ambient operation within the limits of the steam turbine, and to allow independent operation of the gas turbines. For most utility applications, this requires several large (15-ft square for the W501), dampers and a rather costly all-sevice to make up the complete bypass system.

The dampers normally will develop a leakage of about 2 to 3 percent over a period of time, thereby degrading cycle performance. In addition, the dampers have to be operated at full gas flow which can result in aerodynamic vibration, as well as reduced plant reliability. The plant described in this paper does not utilize the bypass system. Instead, the steam plant has been designed so that the functions of the bypass system can be handled in other ways by the use of equipment normally provided.

1. An outage of the steam turbine will result in the use of a steam bypass from the inlet steam line to the condenser, allowing continued operation of the steam generator unfired and the condenser with the steam turbine out of service.

2. The condenser is designed with a divided water box so that a leak in a condenser tube can be serviced while continuing to operate on the remaining half of the tube bundle.

3. The overall steam system has been designed for rapid start-up, and, therefore, the requirement to operate the gas turbines independently of the steam plant is of little value. The entire plant can be brought to approximately 50 percent load in 30 min. and full load in 60 min. from standby. This means that for peaking requirements, a high efficiency block of power
the gas turbine to operate when the steam plant is out of service.

Electric heaters have been provided in the steam generators and are sized so that no damage due to freezing will occur during a low ambient start. These heaters also maintain the steam system in a ready to start condition at an overall cost for the 240-MW plant of approximately $10 to $15/hr.

PLANT OPERATING CONCEPT

The control system is designed so that the plant can be controlled by one operator from a central control room. Automation is incorporated to relieve the operator of complex control functions which require constant attention.

During start-up from cold plant to standby and operation at standby, the equipment alarms, trips, and start-up sequencing are provided by relay logic. Equipment is started either manually or automatically. The plant is manually controlled from the central control room during standby, and the plant's computer may be serviced at this time. Equipment, which is required to be in service, is remote-manually operated. During cold start and standby, an annunciator lamp panel informs the operator of unsatisfied requirements for start-up from standby.

The operator initiates start-up from standby by selecting the gas turbines to be started and the load desired. From standby to full load and back to standby, the steam turbine, gas turbines, and boiler combustion systems are controlled by a hybrid control system composed of a P-2000 stored program digital computer and solid-state analog controllers. The digital computer also provides monitoring, alarm, and emergency shutdown functions over this range of operation.
Control positioning is pneumatic with the exception of the hydraulic actuators on the steam turbine stop and control valves.

**OPERATION FROM COLD PLANT TO STANDBY**

The following operations are required to establish the standby condition: All electrical buses and load centers are energized. The condenser is supplied with cooling water, and the ejectors exhaust the condenser to a vacuum of 1.5-in. Hg Abs. The standby boiler feed auxiliaries are started and the boilers are brought to 300 psi by electric heating. The auxiliary tube oil pumps and gland steam system are put into operation, and the steam and gas turbines are placed on turning gear. The motor-operated isolation valves (3) and (4) in the main steam and turbine extraction lines, respectively, are opened. (Valve numbers refer to Fig. 6.) The computer is energized and prepared for operation. When one operation is dependent upon the completion of others, the necessary plant status information is supplied to wired logic which controls the start-up sequence.

**OPERATION FROM STANDBY TO FULL LOAD WITH TWO GAS TURBINES**

After verifying that start-up requirements are met, the computer will start the required auxiliaries, then accelerate, synchronize, and load the turbines. The gas turbines are accelerated and held at 3600 rpm. The fuel valves are operated to maintain the desired acceleration within specified limits on blade path and exhaust temperature and compressor surge margin.

The afterburners are lit when there is sufficient gas turbine exhaust flow available and when gas turbine combustor ignition has been verified. The afterburners may be lit only if both condensate pumps are operating, and fire to bring the boilers up to steam turbine minimum flow conditions. The steam turbine bypass valve (5) opens when the boiler pressure rises above the standby level and closes when the steam turbine accepts load. It also opens on emergency trips. The steam turbine throttle valve (6) starts to open when the temperature and pressure of the steam coming from the waste heat boilers reach the levels required for steam turbine starting. The valve is then operated to control the acceleration of the steam turbine or to prevent the boiler pressure from falling below its low limits, whichever is calling for the smaller opening. The steam temperature is limited with the superheater bypass valve (7) and afterburner fuel flow.

The generator on the steam turbine shaft is connected to a winding on the low voltage side of the main transformer with the main high voltage breaker open (Fig. 7). When the steam temperature reaches the required level (approximately 600 °F), the steam throttle valve opens and the turbine is brought to speed and synchronized. The gas turbines are then synchronized and the plant is ready to accept load.

Synchronization occurs 20 min. after initiation of start-up from standby (Fig. 3). The combined initial loading of the generators is approximately 5 percent of rated plant output. The gas turbines are brought to full load in 14.5 min. after synchronization, providing more than 50 percent plant load within 30 min. The steam turbine requires an additional 30 min. to attain full load, for a total of 60 min. from standby to full load on the plant.

At minimum plant load, the afterburner control set point remains at its minimum and the afterburners fire at the level required to maintain the smaller of minimum stable afterburner fuel flow or minimum steam turbine bypass chamber pressure. The throttle valve (6) in the main steam line acts to prevent the boiler pressure from falling below minimum.

The inlet steam conditions and power output of the steam turbine are determined by the amount of supplemental firing selected by the operator and the gas turbine exhaust conditions. For best plant efficiency at part loads (Fig. 9), the afterburners are fired at the minimum rate until the gas turbines are fully loaded.

**LOCAL CONTROLS**

In addition to the computer control, the plant contains several independent local control loops. Valve (8) in the feedwater line from the condensate pumps to the deaerator heater is controlled by the low-pressure drum level control. When the pressure at the turbine extraction point exceeds the heater pressure, the check valve (9) in the extraction line opens, thereby allowing steam to flow from the turbine to the heater to supplement the steam generated in the low-pressure drum. Valve (10) in the high-pressure drum feedwater line is controlled by the drum's three element level control. As this valve closes, the economizer recirculation valve (11) opens to maintain full flow through the economizer, thereby preventing economizer steaming. When the level in the condenser headwell is low, valve (12) admits water from the makeup storage tank to the deaerator. This increases the feedwater flow to the low-pressure drum.
causes valve (3) to partially close, thereby decreasing the flow from the hotwell. Valve (3) allows condensate to enter the makeup storage tank when the hotwell level is high. Fluid is periodically transferred to the makeup storage tank through valve (4) as the level in the drain collecting tank rises. Valve (5) admits water to the makeup storage tank from the demineralizer. The amount of blowdown is controlled by valve (6).

CONCLUSION

Through the careful selection of cycle parameters and method of operation, all of the major operational complexities of the steam cycle can be eliminated with no additional complexities being added by the combination of gas and steam turbines. In this paper, we have shown that the advantage of high efficiency characteristic of the combined cycle can be retained in a simple, easily operated power plant.