THE ECONOMIC EFFECTS OF CONDENSER BACKPRESSURE ON HEAT RATE, CONDENSATE SUBCOOLING AND FEEDWATER DISSOLVED OXYGEN

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ABSTRACT

Variations in condenser backpressure about design can impact the economic operation of a turbogenerator unit in terms not only of heat rate, but also of the cost of chemicals used to compensate for the dissolved oxygen concentration in both the condensate and feedwater. These effects can be adjusted by employing means to control condenser backpressure and this paper examines how the costs of these effects can be evaluated and suggests some approaches for the active control of backpressure.

INTRODUCTION

There are two principal modes for operating boiler/turbogenerator units designed according to the Rankine Cycle, namely (1) the turbine-follow mode and (2) the boiler-follow mode. In the *turbine-follow* mode the turbine governor is set to control the generator load while the boiler control system adjusts the fuel firing rate and other parameters so as to maintain, as close as possible to their design values, the pressure and temperature of the live steam at the turbine throttle. Fossil-fired units that are centrally dispatched usually operate in this mode.

On a unit controlled in this way, a rise in condenser backpressure will tend to cause the end point enthalpy to rise, resulting in a reduction in generated power. However, the governor will respond and increase both the throttle and, consequently, the exhaust flows so as to restore the generated power to the preset level. The rise in unit heat rate caused by the increased fuel flow will be only partly offset by the rise in condensate temperature at the hotwell.

On a fall in condenser backpressure, the reverse will occur; but if it falls below the point where the exhaust annulus become choked, then excessive condensate subcooling will result, establishing a limit to the improvement in heat rate resulting from the lower backpressure. Subcooling will also tend to increase the dissolved oxygen (DO) level since the solubility of O_2 rises as the condensate temperature falls. Additional feedwater treatment chemicals will now be required to compensate for the increased DO, so further detracting from the revenue benefit that resulted from the original drop in back pressure. Clearly the system exhibits behaviors that may show there is an optimum or, alternatively, minimum backpressure at which the unit should be operated.

In the *boiler-follow* mode, the fuel-firing rate or, in the case of a nuclear power plant, the steam generator reaction rate, are set at a fixed value. The turbine governor now adjusts the throttle valve (and therefore generated power) so as to maintain the steam pressure at the throttle valve inlet at its design value. In this mode, a rise in condenser backpressure will, by also raising the Usable Energy End Point (UEEP), cause a drop in power for the same net heat input to the system; while the reverse will occur when the backpressure falls. The effect on dissolved oxygen is similar to that in the turbine-follow case. However, according to the new EPRI In-leakage Guidelines (EPRI, 2000), nuclear plants have placed strict limits on DO levels due to the corrosion consequences experienced in the past. For PWR's, a DO level of below 10 ppb is mandated. For BWR's, General Electric recommends a DO level of at least 20ppb (and no greater than 200 ppb) in order that steel components in the reactor may become passivated.

Condensate Subcooling

Condensate subcooling is often of concern, especially during the winter months. It is defined as the saturation temperature corresponding to the vapor pressure at the condenser inlet hood minus the actual temperature of the condensate in the hotwell.

Ideally, condensate subcooling should not occur since this means that, during the condensation process, excess heat has been removed from the cycle without generating any additional power; and this heat will need to be replaced by adding fuel.

Condensate subcooling occurs frequently due to inadequate original condenser design, especially in not having allowed enough vapor to bypass the tube bundles and reheat the condensate as it cascades down through them. Some remedies may be found in adding steam sparging to the hotwell, recycling the condensate through sprays or increasing the laning between the tube bundles. Clearly, should there be an inherent degree of subcooling contained within the original design, it is only subcooling in excess of this value that should be considered as amenable to correction by some form of backpressure control action.

Excess Heat Removal Due to Choking of the Exhaust Annulus

Excessive heat removal can also occur if the exhaust annulus has a tendency to choke under certain conditions. Should the condenser backpressure be allowed to fall below the value it assumes at the onset of choking, then heat will be removed without any increase in the amount of power generated and, in the case of a unit operating in the turbine-follow mode, has to be replaced by the adding more heat to the cycle in the form of fuel.

EFFECTS OF BACKPRESSURE ON RANKINE CYCLE PERFORMANCE

Effect of Operating Factors on Condenser Back Pressure

The turbine thermal kit data is based on an assumed value of the condenser backpressure but, in fact, the actual backpressure experienced will depend on:

- Condenser design details
- Variation in design cleanliness factor with load
- Amount of latent heat to be removed – a function of both generator load (i.e. exhaust flow rate) and condenser backpressure
- Cooling water inlet temperature
- Cooling water flow rate – number of C.W. pumps operating and/or extent of tubesheet fouling
- Degree of fouling of the condenser tubes
- Concentration of non-condensibles which have accumulated in the condenser shell or, alternatively, the amount of air in-leakage into the system
- Performance of air removal system

At any given point in time the combined status of these operating factors will determine the relationship between heat rate and load. The first three factors are inherent in the design of the unit and are difficult to change; while the last three factors can be improved by appropriate maintenance, as can fouling of the tubesheet. The two factors most amenable to some form of on-line control are the cooling water inlet temperature and flow rate, although a few plants have also experimented with the injection of inert non-condensibles (e.g. nitrogen) as a means of controlling both an increase in back pressure and the maximum level of dissolved oxygen in the hotwell condensate.

Rankine Cycle Model

A simplified Newton-Raphson model of a reheat Rankine Cycle unit was used to study the effect on heat rate with a unit operating in either the turbine-follow or boiler-follow modes. Figure 1.0 shows the pressures (psia), temperatures (ºF) enthalpies (BTU/lb) and flows (MM lb/h) throughout the cycle for the reference case defined as a load of 452.75 MW, a back pressure of 2.68 in.Hg and a fuel firing rate of 3704.2 MMBTU/h. The high pressure and low pressure feedwater heaters were considered to be shell and tube type heat exchangers with fixed values of UA, i.e. the product of a design U-coefficient multiplied by surface area. There are usually two sets of high-pressure heaters but, for simplicity, they were here lumped as one. Similarly, the usual three sets of low-pressure heaters were also lumped as one, without any significant loss in the verisimilitude to expected cycle behavior.

Of course, in those plants that have installed a customized PEPSE™ program (PEPSE), it is possible that results similar to those discussed below could be obtained by off-line simulation of the appropriate set of operating conditions for that particular plant. However, the model used for this analysis was more general and could be readily adapted to evaluate both the turbine-follow and boiler-follow modes of unit operation as well as different combinations of operating conditions.

Note that, in the following, *operating margin* for a fossil-fired plant is defined as the difference between revenues and fuel costs in dollars per hour. The fuel cost is assumed to be $2.4/MMBTU and power price $27/MWh. It does not include any fixed operating costs. In a nuclear plant the fuel cost is often included among the fixed operating costs so that the evaluation of a nuclear plant operating in the boiler follow mode will have to take this into account.

. Unit Operating in Turbine-Follow Mode

Figure 2.0 shows heat rate, fuel firing rate and operating margin in dollars plotted against hotwell condensate enthalpy (equivalent to a backpressure range of 1.0 to 4.5 in.Hg), with a turbogenerator operating in this mode at a constant load of 452.75 MW. It is seen that, as the backpressure and condensate enthalpy fall, the heat rate also falls while the operating margin tends to increase. The plot also shows the effect on heat rate and margin should the annulus choke at a backpressure of 1.5 in.Hg

Figure 3.0 shows the distribution of flows and enthalpies throughout the cycle when the backpressure is at 4.0 in.Hg. Comparing Figure 3.0 with Figure 1.0, the higher backpressure and UEEP have caused all the steam and water flow rates throughout the system to increase, together with the fuel-firing rate; while the higher hotwell condensate enthalpy has resulted in a fall in the extraction flow to only the low pressure heaters. The rise in heat rate (and drop in operating margin) is largely due to the increased steam flow required to maintain load with the increased backpressure, augmented by the drop in water enthalpy at the discharge from the high-pressure heater.

To test the effect of annulus choking, the assumption was made that the exhaust flow at the reference case was actually choked and the back pressure of 1.60 in.Hg was then dropped to 1.0 in.Hg with the exhaust flow fixed (i.e. choked). While the power was unaffected, the lower hotwell enthalpy resulted in a lower HP heater water discharge enthalpy, even though the extraction flows to both heaters increased. The overall result was an increase in heat rate from 8212 to 8240 BTU/kwh and a not insignificant ($30/h) drop in operating margin from $3301 to $3271/h. *This confirms that the backpressure should not be allowed to fall below the point where choking first occurs.*

It was indicated earlier that condensate subcooling caused either by inadequate condenser design or too low a cooling water inlet temperature should be avoided. The margin data plotted in Figure 2.0, together with the condensate temperature corresponding to enthalpy obtained from the ASME Steam Tables (ASME, 1993), may be used to determine the cost per degrees of subcooling. Note that the $30/h increase in operating costs referred to above was associated with a 14.76 °F drop in condensate temperature, so that a rule of thumb for the effect of subcooling on a unit of this size might be $2.03/h per °F.

. <u>Unit Operating in Boiler-Follow Mode</u>

Figure 4.0 shows heat rate, fuel-firing rate and operating margin in dollars plotted, again, against hotwell condensate enthalpy (equivalent to a backpressure range of 1.0 to 4.5 in.Hg), the turbogenerator operating in the boiler-follow mode with a constant fuel input rate of 3704.2 MMBTU/h. As before, it is seen that, as the backpressure and condensate enthalpy fall, the heat rate also falls but, in this mode, the generated power and operating margin both tend to increase. The plot also shows the effect on heat rate and margin should the annulus choke at 1.5 in.Hg

Figure 5.0 shows the distribution of flows and enthalpies throughout the cycle when the backpressure is at 4.0 in.Hg. Comparing Figure 5.0 with Figure 1.0, the higher backpressure has caused all the steam and water flow rates throughout the system to increase only slightly; although the higher hotwell condensate enthalpy has caused a fall in the extraction flows to *both* feedwater heaters. The rise in heat rate (and drop in operating margin) is largely due to the drop in revenues from generated power as the backpressure increases, since the water enthalpy at the discharge from the high-pressure heater is hardly affected: if anything, it tends to rise. For this reason the steam flows throughout the system remain essentially unchanged and a direct correlation can be made between generated power and condenser backpressure.

Of course, nuclear power plants operate in the boiler-follow mode, as do the steam turbines in combined cycle plants. However, only the former operate with a sensibly constant heat input to the steam generators (or radiation level). Bearing in mind the close relationship between power and back pressure, several nuclear plants have experienced a significant improvement in generation capacity after fouling deposits were removed from the condenser tubes, in particular the nuclear power plants at Clinton (Stiesma et al, 1994) and Peach Bottom (Karen, 1994)

. <u>Effect of Back Pressure on Feedwater Dissolved Oxygen</u>

Most mechanical engineers involved in the operation of condensers only consider a poor performance as it affects heat rate, backpressure and heat transfer, especially the increased difficulty in removing the latent heat from the vapor exhausted from the low pressure stage of the turbine. These are the thermodynamic effects of observed changes in backpressure. However, a secondary but still important effect is the impact of backpressure on hotwell condensate temperature and the solubility of oxygen in the condensate under these conditions. Dissolved oxygen tends to cause corrosion in both non-ferrous heat exchangers and the carbon steel components in boilers and steam generators and these effects must be countered by treatment with a chemical such as hydrazine.

There are many possible sources of dissolved oxygen in condensate. A principal source is the oxygen in any ambient air that may leak into the shell side of the condenser. Dissolved oxygen can be also contained in make-up water or in certain drains passed to the condenser from other parts of the turbine cycle. Meanwhile, one of the purposes of the condenser is to deaerate the condensate; but the degree to which the DO is reduced will largely depend on the condensate temperature, as will be seen from the solubility/temperature relationship shown in Figure 6.0 (Perry, 1967). If:

H = Henry constant
P_a = Partial pressure of oxygen in vapor above water (atm)
X_a = Mole fraction of oxygen in water

Then

$$X_a = P_a * H \qquad (1)$$

For comparison, the moles oxygen in solution with a DO level of 10 ppb, equivalent to an oxygen partial pressure of 0.000979 atm, is plotted in Figure 7.0.

The EPRI In-leakage Guidelines (EPRI, 2000) discuss how Hydrazine is used as a feedwater treatment chemical to control these trace amounts of oxygen and to supplement mechanical deaeration in the system. The condensate/feedwater cycle will decompose the hydrazine to ammonia (plus hydrogen and nitrogen) and increase the pH of the water. At some plants this reaction may be supplemented with the addition of ammonium hydroxide or morpholine to maintain the desired pH level. The basic reaction that describes the net result of oxygen reduction in feedwater treated with hydrazine is:

$$N_2H_4 + 0_2 \text{ ---- } > N_2 + 2H_20$$

This reaction may also be indirect as follows:

$$6Fe_20_3 + N_2H_4 \text{ ---- } > 4Fe_30_4 + N_2 + 2H_20$$
$$4Fe_30_4 + 0_2 \text{ ---- } > 6Fe_20_3$$

and/or

$$4CuO + N_2H_4 \text{ ---- } > N_2 + 2H_20 + 2Cu_20$$
$$2Cu_20 + 0_2 \text{ ---- } > 4CuO$$

The formation of ferric and cupric oxide must be considered as a mechanism for the consumption of hydrazine. It is of interest to note that hydrazine will decompose at temperature in accordance with either:

$$3N_2H_4 \text{ -----}> N_2 + 4NH_3$$

or

$$2N_2H_4 \text{ ---- } > N_2 + H_2 + 2NH_3$$

Thus, hydrazine decomposes into gases of both low solubility (nitrogen and hydrogen), and of high solubility (ammonia) that will initially alter the pH of the feedwater and then vaporize with the steam in the steam generator. This ammonia of course can be a source of ammonia condensate corrosion on the outside of non-ferrous condenser tubes.

Hydrazine is, of course, only one of several chemicals available to compensate for changes in DO levels, although it is probably the one most frequently used.

The chemical feed rate, and its cost, is a function of both condensate flow rate and dissolved oxygen level and varies from plant to plant. Unfortunately, the cost rises as the backpressure, and condensate temperature fall and this tends to offset some of the heat rate benefits that result from the same drop in back pressure. The cost of chemicals will also rise if the high DO level is due to excessive air ingress but, since this already caused the backpressure to rise, the chemical cost attributed to air ingress is in addition to that due to the rise in heat rate.

Experience also shows that the level of DO tends to rise as the generated power level falls. This means that a dissolved oxygen problem experienced close to full load may become more severe should the load be allowed to decrease.

It is also of interest to note that the equivalent amount of air absorbed in feedwater with a DO of 10 ppb and a condensate flow rate of 2 million lb/h is only 0.018 scfm. This should be compared with the 5 scfm of air ingress, considered to be acceptable for a unit of this size (ASME, 1998).

BACK PRESSURE OPTIMIZATION STRATEGY

It is clear from the above that a fall in condenser backpressure is accompanied by an improvement in heat rate but can be offset by the cost of any condensate subcooling, coupled with a rise in the cost of feedwater treatment chemicals should the DO concentration increase. The auxiliary power used should also be taken into account

The turbine-follow model outlined above allows an evaluation of the economic effect of variations in condensate enthalpy *at a given load*: using condensate enthalpy as the independent variable automatically includes the effect of any condensate subcooling. Then, by constraining the exhaust flow at the value it assumes when the exhaust annulus becomes choked *at the given load*, this allows the effect of choking on heat rate and fuel flow rate to be estimated.

In the boiler-follow mode, the model again allows the effect of condensate enthalpy variations to be evaluated in economic terms as well as the improvement in generated power that tends to accompany a drop in backpressure. The manner in which the operating costs are evaluated will vary between fossil-fired and nuclear power plants but are still quantifiable.

The cost of feedwater treatment chemicals is initially a function of condensate flow rate and dissolved oxygen level as well as the unit cost of the chemicals. In the absence of excess air ingress, the relationship between DO and condensate hotwell temperature (and the equivalent hotwell enthalpy) can be estimated using the curve of Figure 6.0.

Combining the operating margin vs. condensate enthalpy relationship with the cost of chemicals vs. condensate enthalpy relationship allows the total operating margin vs. condensate enthalpy to be derived. A search for the enthalpy corresponding to the maximum point in the margin relationship determines the optimum condensate enthalpy at which the unit should be operated. Adding the change in enthalpy corresponding to the natural degree of subcooling to the optimum enthalpy, provides the enthalpy corresponding to the optimal backpressure, the latter being determined by reference to the Steam Tables (ASME, 1993)

Should the relationship contain no maximum, the model is still useful in quantifying the economic benefit to be gained from performing a specific maintenance activity. For instance, there is a level of air ingress, or even fouling, which may be allowed to persist for a time, especially during the winter months, so long as subcooling or exhaust annulus choking can continue to be avoided.

POSSIBLE ON-LINE BACK PRESSURE CONTROL STRATEGIES

Having established the criteria for determining the backpressure at which the unit should be operated so as to obtain maximum economic benefit, the question arises as to what means are available to effect any necessary backpressure changes on-line, so avoiding having to shut the unit down to perform maintenance. Among these means are:

- Allowing some of the condenser cooling water discharge to bypass the cooling towers
- Changing the cooling water flow rate by varying the number of circulating water pumps in operation
- Partially closing the isolation valves on one or more water boxes
- Adjusting the capacity of the air removal system
- Injecting an inert gas (e.g. nitrogen) into the condenser shell

Cooling Tower Bypass

This is the preferred method for affecting condenser backpressure by making an adjustment to the waterside conditions. The method is fairly easy to implement using control valves and the bypass flow can be adjusted smoothly from zero up to some maximum value. Clearly, the objective is to reduce the amount of heat removed from the water circulated back to the condenser, so raising the condenser cooling water inlet.

Varying the Number of C.W Pumps in Operation

Changing the number of C.W. pumps in operation will directly affect the water flow as well as the tube water velocity, the latter, in turn, affecting the waterside film thermal resistance and tube heat transfer coefficient. There is however the risk that the lower tube velocities will allow silt and other sedimentary material to become deposited on the insides of the tubes, so increasing fouling and introducing a new and, perhaps, unnecessary maintenance problem. However, unit operating costs are clearly reduced when fewer C.W. pumps are in operation.

Partially Closing Waterbox Isolation Valves

This is only appropriate if the valves have been designed to be used in this way and must, again, be implemented with care to avoid silt being deposited on the tube walls.

Adjusting the Capacity of the Air Removal System

This is a means of affecting the conditions on the shell-side of the condenser: allowing some non-condensibles to accumulate increases the shell-side thermal resistance and, thus, the overall tube heat transfer coefficient. Even though the concentration of air in the vapor surrounding the tubes may rise, the associated increase in backpressure and condensate temperature may prevent the concentration of dissolved oxygen in the condensate from rising significantly.

Injecting an Inert Gas

Nitrogen is the preferred gas employed for this method, which makes adjustments to the shell-side conditions. It has been used in several plants and has the advantage of raising the backpressure without increasing the amount of air accumulating in the condenser shell or affecting the level of dissolved oxygen in the condensate. Nitrogen can, however, be costly if used for long periods of time.

CONCLUSION

Changes in condenser backpressure affect not only the thermodynamic relationships within the Rankine Cycle in a number of ways but can also affect the level of dissolved oxygen in the condensate. Since the latter affects the corrosion of feedwater heaters, boilers and steam generators, steps are usually taken to compensate for DO levels by the admission of chemicals (such as hydrazine) into the condensate returned to the boiler or steam generator on the unit, the cost varying directly with the DO level. Using simple unit performance modeling techniques, it is possible to evaluate the economic benefits which would result from varying the backpressure, taking account of any associated increase in condensate subcooling, possible choking of the low pressure turbine exhaust annulus and any changes in the cost of feedwater treatment chemicals.

It is another diagnostic tool available to plant management to help maximize plant revenues in today's highly competitive utility environment.

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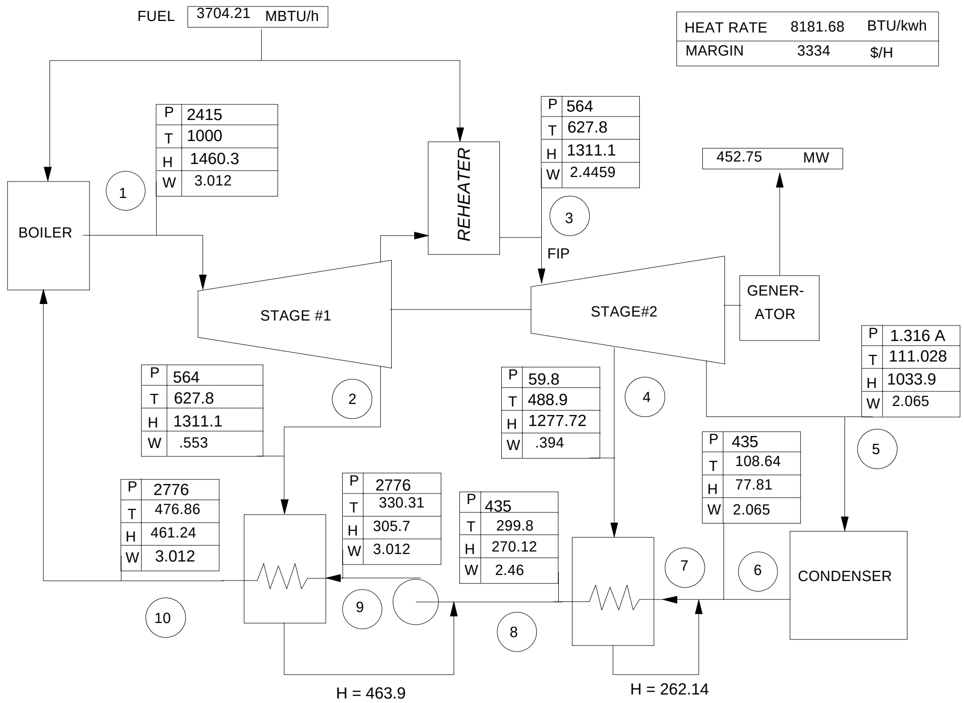
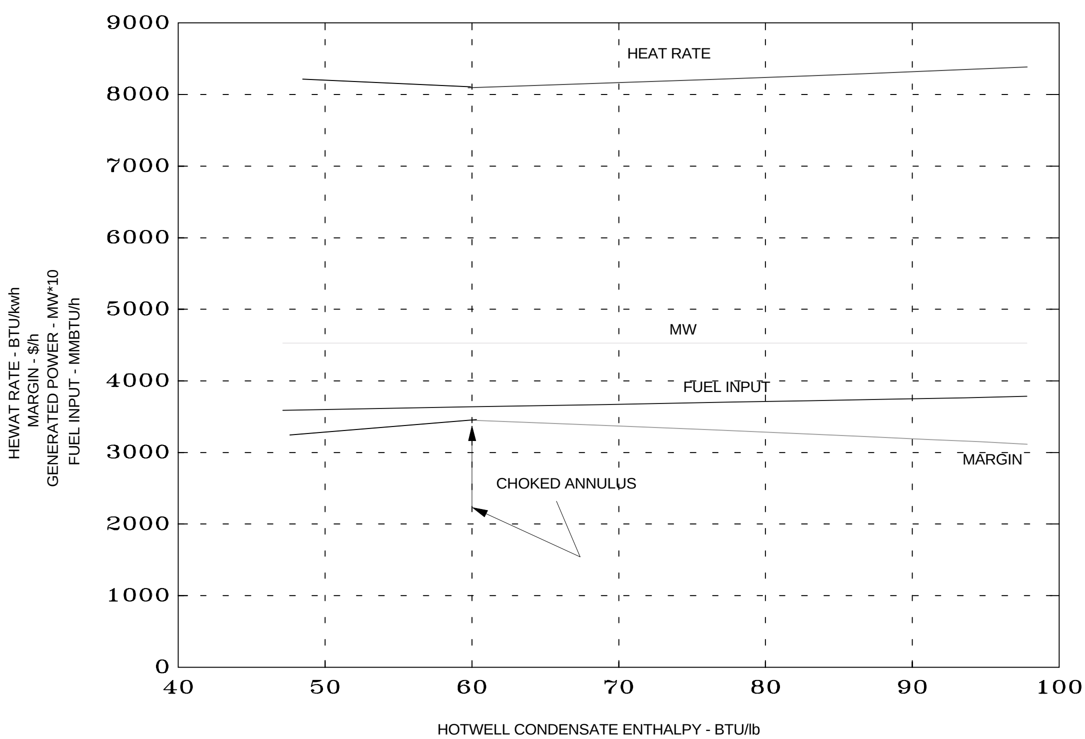


SIMPLIFIED RANKINE CYCLE SIMULATION

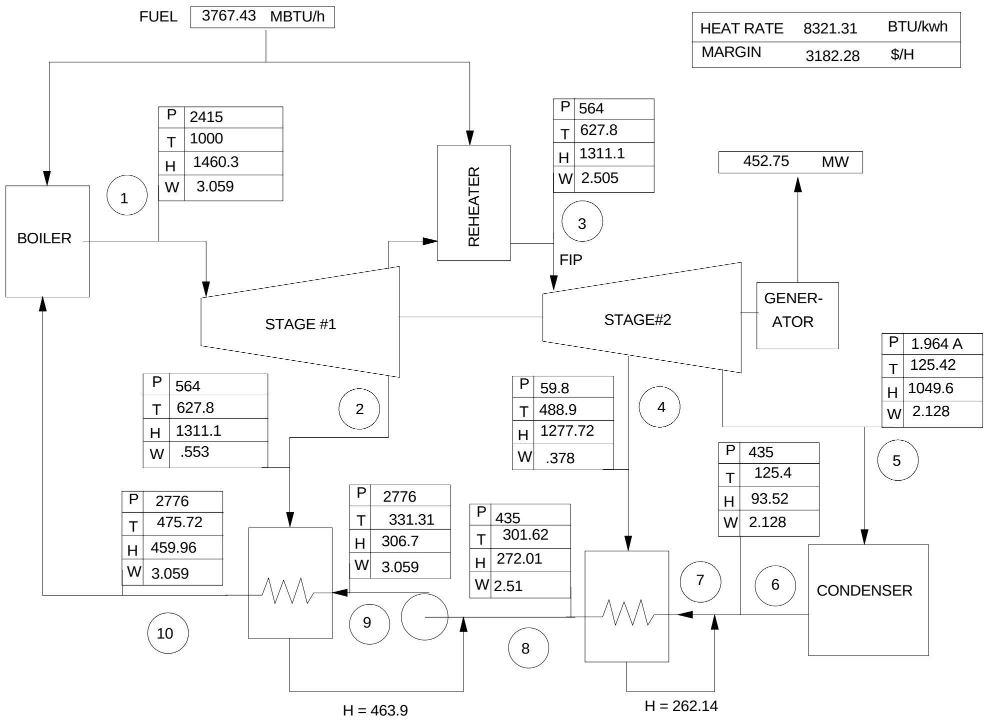
REFERENCE CASE

FIGURE 1.0



TURBINE-FOLLOW MODE

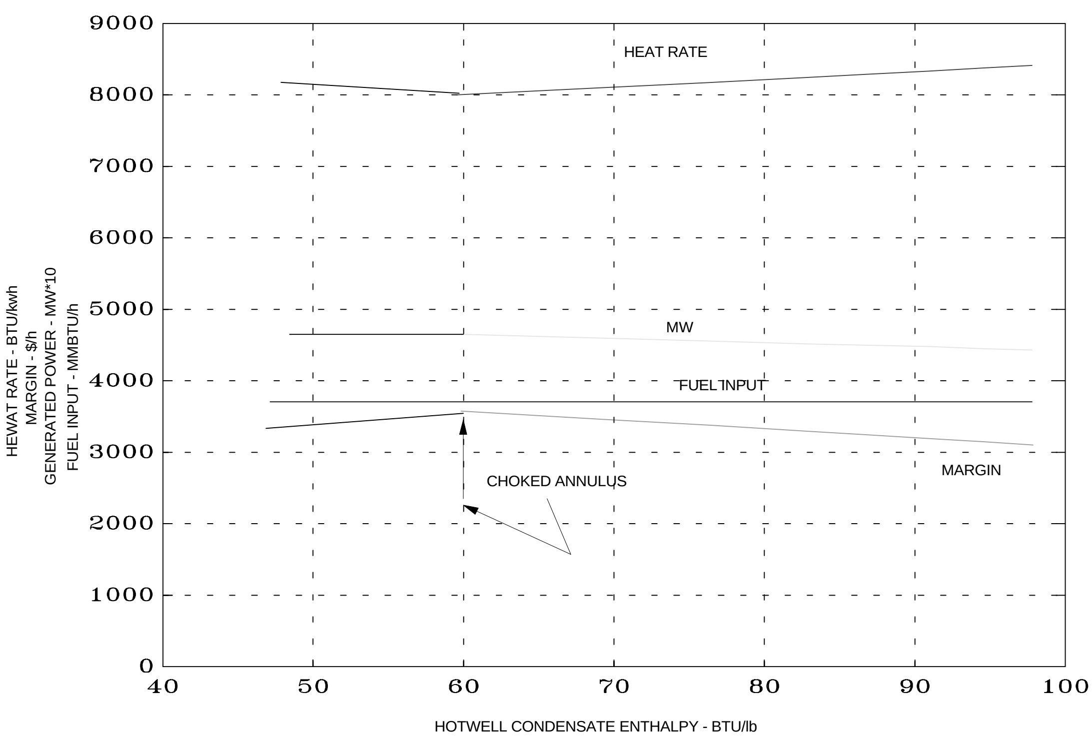
FIGURE 2.0



SIMPLIFIED RANKINE CYCLE SIMULATION

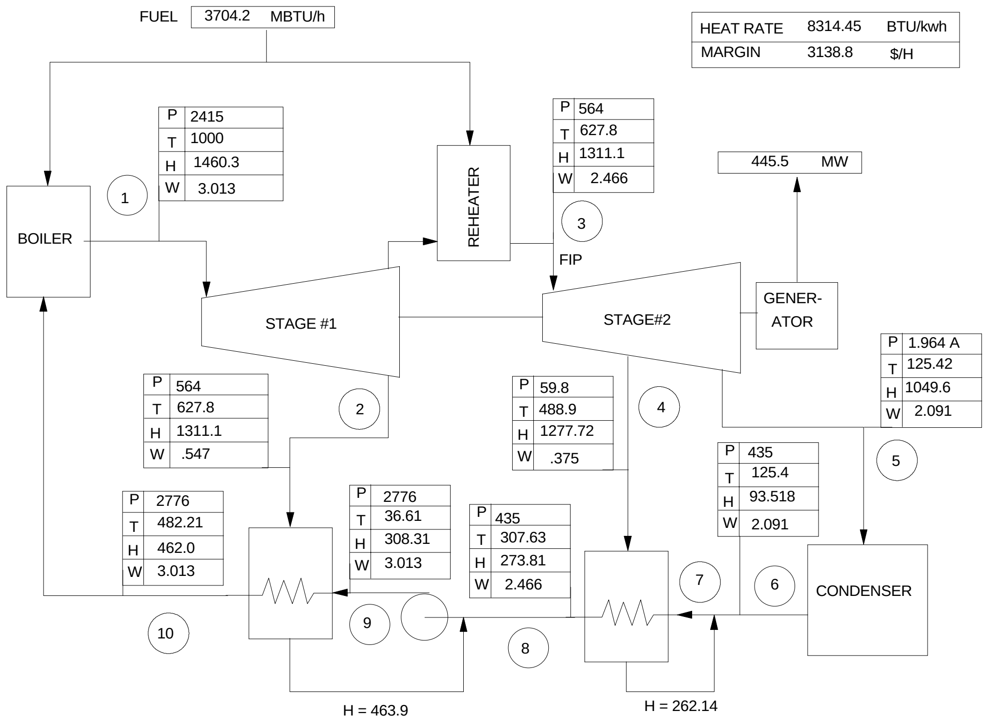
TURBINE FOLLOW - BACK PRESSURE = 4.0 in.Hg

FIGURE 3.0



BOILER-FOLLOW MODE

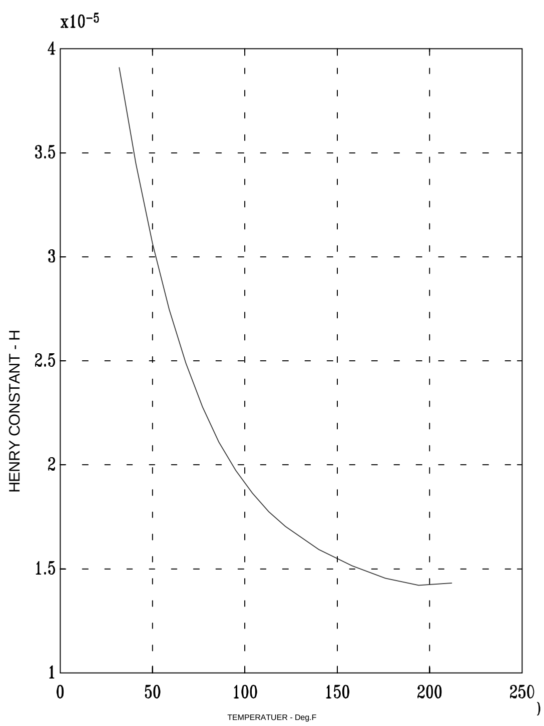
FIGURE 4.0



SIMPLIFIED RANKINE CYCLE SIMULATION

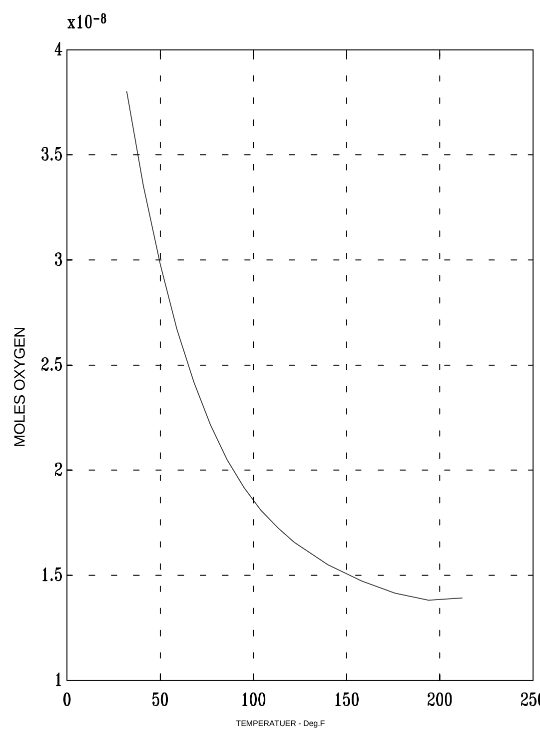
BOILER FOLLOW - BACK PRESSURE = 4.0 in.Hg

FIGURE 5.0



SOLUBILITY OF OXYGEN IN WATER

FIGURE 6.0



SOLUBILITY OF OXYGEN IN WATER
AT PARTIAL PRESSURE OF 0.000979 atm

FIGURE 7.0

Table of Conversions to SI Units

U.S. Units	Conversion Factor	SI Units
In.Hg	25.4	mm.Hg
psia	6.894	KPa
ºF	(ºF-32)*5/9	ºC
BTU/lb	0.5556	Kcal/kg
MMlb/h	453.59	T/h
BTU/kwh	0.252	Kcal/kwh