Low Load Boiler Modeling and Application

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ABSTRACT

PEPSE is utilized to calculate boiler efficiency at very low loads. Specifically addressed is the loss of boiler efficiency due to the increased excess air requirement at low load. PEPSE's results are then verified by testing on a generating unit. These results are used to more accurately estimate low load heat rate, allowing the power dispatcher to consider the additional costs associated with operation at low load when making economic dispatch decisions.

1.0 Introduction

Commonwealth Edison (ComEd) is a large Midwest utility with 23,645 MW of generating capacity. Our service territory is approximately the northern fifth of Illinois including Chicago. The generating mix consists of 12 nuclear units (12,045 MW), 24 fossil units (10,268 MW), and peaking units (1,332 MW). We serve over three million customers in our territory.

Due to economics, the nuclear units are baseloaded, with the fossil units doing most of the load following. The large base load capacity leaves the power dispatcher with difficult decisions every night. Reducing system generation requires one (or more) of three options:

1) Reduce fossil generation to minimum.
2) Cycle fossil units off line.
3) Reduce power level at nuclear units.

Choosing a combination to reduce system generation is a very complicated task. Typically a computer executes a complex economic algorithm, accounting for fuel costs, off-system sales, heat rates, etc. This is then tempered by the day's operating conditions. For instance, unit minimum generation capabilities and seasonal effects must be considered. The most critical question, however, remains an economic one: What combination of on line units and unit loading minimizes the cost of operating the system?

Reducing fossil generation to minimum is usually the choice that best optimizes the system. Therefore, minimizing the fossil units' steady state minimum load is important to operating the system as cost-effectively as possible. Efforts to lower minimum loads at our fossil stations have been very successful. Some fossil units can operate in the range of 5%-25% of full load. Being able to "turn down" to such low loads has allowed the less expensive nuclear units to operate at or near full capacity most of the time, and has greatly reduced the frequency that fossil units need to be brought off line.

Because our fossil units are often operated at loads significantly below their normal operating range, determining the cost of operation at these sub-minimum loads is important. Testing or detailed analysis is required to find out the effect it has on efficiency (ie. incremental heat rate), otherwise errors will occur in estimating operating costs. Figure 1 shows an example of a typical incremental heat rate curve.

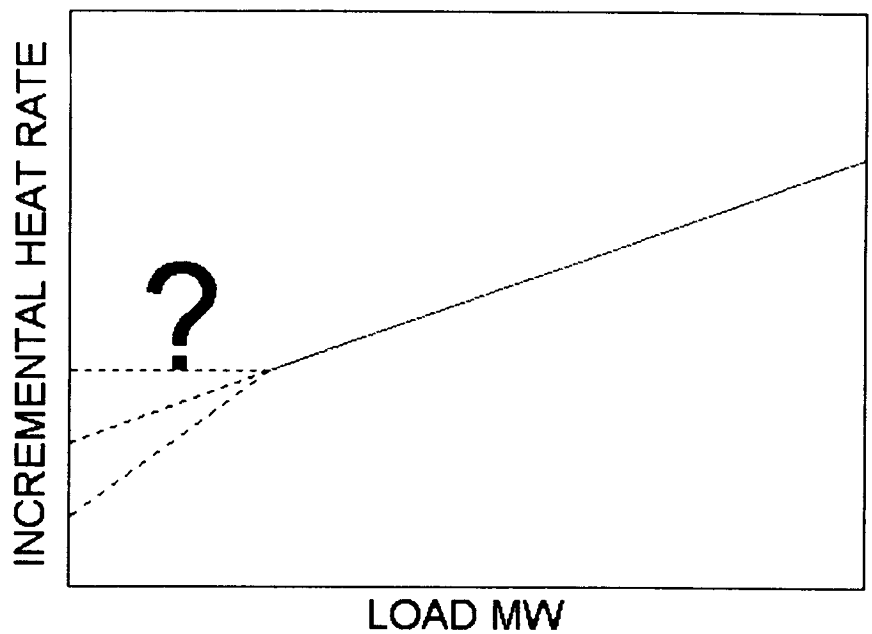

FIGURE 1

Below 25% of boiler Maximum Continuous Rating (MCR), units are operated differently than they are at higher loads. For instance, National Fire Protection Association (NFPA) code requires boilers to maintain a minimum of 25% of maximum total air flow at all times. This requirement causes low load boiler operation to deviate from normal operation, which is with 10%-20% excess air. Maintaining 25% total air flow can increase excess air levels above 100%. This will introduce a boiler efficiency penalty (see discussion below). Also, at very low loads (the level of load being determined by the individual turbine cycle) there can be departures from the normal turbine cycle. Typical turbine cycle deviations include removal of feedwater heaters from service because of drainage problems, and opened low point drains on the steam chest. Obtaining accurate heat rates below 25% of full load by quantifying the effects discussed above is the subject of this paper.

2.0 Discussion

Due to the amount of time our fossil generating units operate at very low loads, it is important to determine the cost of operation at those loads. The high load cost of operation is typically determined by testing and operating history. Extrapolation from high load costs accurately depicts mid-load costs to a point. Further extrapolation of the cost curve down to loads below the point where the thermal cycle changes probably would underestimate the cost of operating our units. This could lead to inaccuracies in decision making by power dispatchers. The temptation to continue to extrapolate costs is driven by the difficulty of conducting tests at low loads.

At low loads, there are several different operating methods that can introduce inefficiencies. These methods include both the turbine cycle and boiler cycle effects mentioned above as well as others. The main boiler effect is a reduction in boiler efficiency due to increased excess air. If any of the operating conditions mentioned above are in effect, utilizing the method of extrapolation to estimate low load heat rate will be in error. Investigation revealed that only one of our stations reached loads low enough that the turbine cycle was significantly affected. However, the reduction in boiler efficiency was affecting several of our units.

Fossil fuel (coal, oil, gas) is burned by combining the fuel with air at the proper temperature to achieve combustion of the fuel. There is an ideal amount of air that should be combined with the fuel to obtain optimum and complete combustion. This amount is called the theoretical or stoichiometric air. In practice, more than theoretical air is needed to assure complete combustion. This excess air is necessary because the fuel and air mixing is not perfect. The typical amount of excess air used in utility boilers is 10% - 20% of theoretical air.

$$\text{Total Air} = \text{Theoretical Air} + \text{Excess Air}$$

Because the excess air is heated from ambient temperature to stack temperature (250° - 300° F) before leaving the cycle, any excess air used increases the heat loss to the system. This is called stack loss, which has a major effect on boiler efficiency.

Boiler efficiency is defined as the percent of total heat input that is used to heat the working fluid (water-steam). It is typically measured in one of two ways, the heat loss method, or the input-output method. Due to measurement accuracy difficulties involved with the input-output method, the heat loss method is more common for measuring boiler efficiency in industry. The equation for boiler efficiency using the heat loss method is:

$$\eta = 100\% - \%\ \text{Heat Losses}$$

Major heat losses include: Unburned carbon, heat in flue gas, moisture in fuel, and moisture from burning hydrogen. A typical operating boiler efficiency for a utility boiler is 89%. Any reduction in boiler efficiency has an effect on total unit costs. Since boiler efficiency and heat rate are directly related, the change in boiler efficiency can be utilized to determine the change in heat rate, provided the turbine cycle does not deviate from normal.

Boiler operators control excess air in an attempt to maintain a balance between losses from incomplete combustion (too little excess air) and additional stack losses (too much excess air). At loads below 25% of maximum, the operator's options for air use are restricted. National Fire Protection Association (NFPA) code requires boilers to maintain a minimum of 25% of maximum total air flow. When a boiler is operated below 25% of maximum output, this requirement holds the total amount of air entering the boiler constant, regardless of output. At very low boiler output levels, excess air can increase above 100% (total air flow over twice theoretical air). This operating mode introduces large stack losses to the generating unit. We use the following method to account for these losses in our estimates of low load costs.

3.0 Method

One way to quantify the stack loss effect on boiler efficiency is to conduct boiler efficiency tests at minimum load on all units. Establishing low load costs in this way would have the advantage of good industry acceptance, and good accuracy. However, this testing process would be prohibitive in both time and money. An alternative method of estimating this effect is to simulate low boiler output operation using PEPSE to predict this effect. The method of computer simulation had the advantage of being relatively inexpensive. Therefore, this was the method of choice.

The study utilized three different boiler models in an attempt to determine the stack loss effect, Collins Unit 1, Will County Unit 4 and Fisk Unit 19. These three units were chosen for several reasons. The first reason was their diversity. Collins 1 is a 4.2Mlb/hr gas and oil fired unit, and was one of the units we were going to test to verify the results. Will County Unit 4 is a 3.9Mlb/hr coal fired boiler that has two furnaces with a superheater and a reheater in each. Fisk Unit 19 is a 2.2Mlb/hr coal fired boiler with a separate superheat and reheat furnace. Another reason for the choice was that these were three units that can operate at very low loads. Collins 1 can operate at around 300 klb/hr steam flow, Will County 4 and Fisk 19 at around 350-400 klb/hr steam flow.

After the models were chosen, the consideration of using the PEPSE Design or Performance Mode needed to be made. Design Mode has the benefit of providing valuable insight into boiler operating temperatures. This information can be very valuable when determining whether operation at low loads is feasible (or even possible). Since these units were already operating at low loads, this information was not as valuable. The purpose of the study was to determine boiler efficiency (by the heat loss method). The Design Mode did not add any resolution to the key heat losses involved in the boiler efficiency calculation, therefore performance mode was adequate to do this study.

The first step of the analysis was determining full load air flow. This design data was not always available. Boilers are rated for a given steam flow. Sometimes test numbers include full load air flow, more often than not they don't. Fortunately this factor is easy for PEPSE to calculate. A boiler model run at full load with design excess air (usually 10% - 20%), will give a good number for design full load total air flow. Fuel flow in the models was controlled by means of air heater gas out temperature. This method of control has the potential to overstate the total fuel flow, since fuel is substituted for some air preheating, thus raising the total air flow. This error however should not be significant. The calculation of boiler efficiency is unaffected by whether the stack heat loss (temperature) is from burning fuel, or from steam air preheating.

The next step was determining the steam flow at the point where the air flow reached the 25% total air flow point. This was a matter of running the load down to around 25% to 30% MCR, and checking air flow by trial and error. After the point was determined where the air flow became fixed, the next step was to reduce load below 25%. This required two sets of controls. The first was the previously mentioned control on fuel flow. The second control functions to maintain a constant mass flow of air into the furnace. This control attempts to fix the air flow out of the demand splitter that feeds the furnace by varying the excess air level of the furnace component. This control set was sensitive, and required some manipulation to converge.

An additional wrinkle that was added to the Fisk 19 and Will County 4 models was the addition of support fuel. Both units use support fuel at low loads to stabilize their fires. Fisk uses natural gas, and Will County uses #2 oil. The addition of support fuel had very little effect on low load boiler efficiency, as the effect of additional hydrogen in the fuel was dwarfed by the stack losses.

All three models predicted the same results, which are summarized in the Figure 2. Because gas has additional losses due to hydrogen in fuel, Collins' (a gas burning unit) numbers are normalized to coal efficiencies. Figure 2 illustrates the boiler efficiency change with boiler load. These data assume operation of the boiler with the NFPA required minimum 25% total air flow. Similar iterations were run for 30% and 35% total air flow, because while 25% is ideal, some units (especially those with older controlling and measuring mechanism) operate with somewhat more than 25% air at minimum load. The results for 30% and 35% total air flow were similar in character to the 25% curve, but the efficiency effect was more severe.

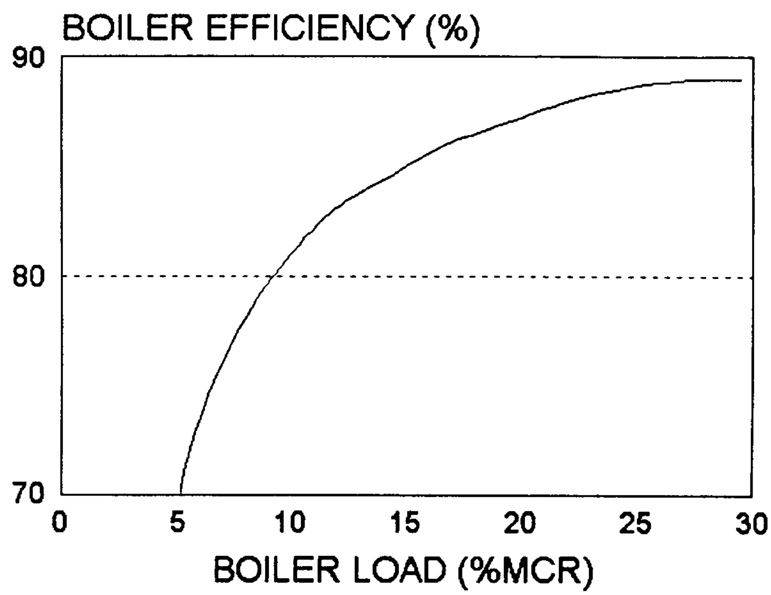

FIGURE 2

To verify PEPSE's results, tests were conducted at ComEd's Collins Station. Collins has five units that are fired with oil and/or natural gas. (All results were normalized to account for additional boiler inefficiency while burning natural gas, when applicable.) Tests were conducted at 90%, 50%, and 25% load. The results of these tests were used to extrapolate expected heat input at the 5% load. We then conducted tests at 5% load and compared the actual test data with the expected values. (The 5% tests were conducted with 25% total air flow in the boilers.) Some tests were conducted with turbine cycle intact and others with the low point drains open. This allowed us to distinguish between boiler cycle losses and turbine cycle losses.

4.0 Results

The tests at Collins verified the PEPSE computer model's prediction of boiler efficiency. Tests predicted a boiler efficiency at 5% of maximum boiler output to be 73%. (PEPSE predicted 72%.) This is 18% below the normal operating efficiency of 89%. The effect of the reduction in boiler efficiency at low load was then added to the costs of all units operated below 25% of full load. Note that the level of total air flow used at each unit can also vary.

The next step was to determine the turbine cycle losses at Collins Station. After accounting for boiler efficiency losses, the turbine cycle reconfiguration that occurs at Collins at low generation levels resulted in an additional 10% rise in heat input. These results were also incorporated into the cost of operation at Collins Station. PEPSE was not used in this step of determining turbine cycle losses. If low load turbine cycle losses were a concern elsewhere in the ComEd system, using PEPSE to determine them should prove as accurate and cost effective as it was in determining boiler losses.

Computer modeling via PEPSE, and actual testing agreed that an extrapolation method would underestimate low load cost of operation. If proper low load cost is a part of the database, power dispatchers have better information available to make their decision as to how to optimally reduce system generation.

UNIT	PEPSE Predicted Blr Efficiency	Tested Blr Efficiency
Collins Unit 1*		
5% MCR	72%	73%
20% MCR	87%	87%
50%MCR	89%	89%
90% MCR	89%	89%
Fisk Unit 19		
5% MCR	71%	N/A
20% MCR	87%	N/A
50%MCR	89%	N/A
90% MCR	89%	N/A
Will Co. Unit 4		
5% MCR	71%	N/A
20% MCR	87%	N/A
50% MCR	89%	N/A
90% MCR	89%	N/A

* COLLINS DATA NORMALIZED TO COAL FIRED OPERATION

5.0 Other Factors / Potential for Further Study

There are many other items that can be included in further study to further fine tune the low load operating cost calculation. Most of these items are unit specific, and therefore would require more individual attention to specific units and models. They are outlined here.

There are several operating conditions that occur at low loads that can be accounted for in PEPSE models. The first is the typical decrease in steam temperature that occurs at low loads. Changes in steam temperature had little to no effect on boiler efficiency, but can have an effect on the turbine, even at very low loads.

Another effect was variable pressure operation. All of our units that operate in a very low load range slide pressure. (Collins' units operate in pure sliding mode.) This has some ramifications due to the higher reheat temperature and the higher SSH temperature, as well as different heat transfer characteristics in the boiler. These effects have very little effect on boiler efficiency, but will have varying effect on unit overall efficiency at low loads, depending on the unit design.

There are also other losses that can be accounted for including poorer condenser pressure due to more equipment under vacuum at low loads. Also, each individual unit has its own idiosyncracies while operating at low loads. These can also be studied to further fine tune the low load cost of operation.

6.0 Conclusion

When operating at loads below 25%, it is important to consider the additional costs incurred. An analysis should be performed to quantify the effect. When possible, test data should be used to verify PEPSE's results. The power dispatcher must be aware of these effects and consider them as he economically dispatches the system.

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