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VALUE IMPACT ASSESSMENT: A PRELIMINARY ASSESSMENT OF IMPROVEMENT OPPORTUNITIES AT THE QUANTICO CENTRAL HEATING PLANT

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SUMMARY

This report presents the results of a preliminary assessment of opportunities for improvement at the U.S. Marine Corps (USMC) Quantico, Virginia, Central Heating Plant (CHP). This study is part of a program intended to provide the CHP staff with a computerized Artificial Intelligence (AI) decision support system that will assist in a more efficient, reliable, and safe operation of their plant.

As part of the effort to provide the AI decision support system, a team of six scientists and engineers from the Pacific Northwest Laboratory (PNL)[a] visited the plant to characterize the conditions and environment of the CHP. This assessment resulted in a list of potential performance improvement opportunities at the CHP. In this report, 12 of these opportunities are discussed and qualitatively analyzed. Sufficient data were not available to establish a performance baseline from which a quantitative analysis could be performed.

The 12 major CHP problems discussed in this report are

- boiler efficiency is less than possible
- boilers are not controlled adequately to minimize corrosion, stress, and damage
- water chemistry is maintained inadequately
- fuel handling and delivery systems are unreliable
- ash handling system is unreliable
- components are not adequately maintained
- fuel is not selected to optimize economic plant performance
- condensate return is lower than possible
- load management is not optimal
- plant staff and contractors work in unsafe situations

(a) PNL is operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLO 1830.

- recordkeeping is inaccurate and incomplete
- workforce is not used as effectively or efficiently as possible.

For each of the 12 problems, the potential economic, safety, and reliability impacts of solving the problems were examined and evaluated. Two principal conclusions were drawn from this assessment:

- many improvement opportunities exist at the Quantico CHP to improve the efficiency, reliability, and safety of the plant
- a baseline study is required to measure the actual quantitative benefits of implementing an AI decision support system at Quantico.

ACKNOWLEDGMENTS

We gratefully acknowledge the valuable contributions of Shawn Bohn and Robert Lucas in collecting and assembling information used in this report. The other members of the Quantico site visits teams--Don Jarrell, project manager, Rex Stratton, Jon Anderson, and Mark Hosa--recorded events and observations that provided part of the basis for this report. Raymond Reilly, program manager, Don Jarrell, project manager, and Kevin Drost provided valuable comments in their reviews of drafts of this report.

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1.0 INTRODUCTION

This report presents the results of a preliminary assessment of opportunities for improvement in the Central Heating Plant (CHP) at the U.S. Marine Corps (USMC) Combat Development Command at Quantico, Virginia. This study is part of a project conducted by Pacific Northwest Laboratory (PNL). It is intended for the development of a computerized decision support system that will assist CHP staff in operating and maintaining the plant in a safer, more reliable, and efficient manner. This work is the third of five tasks in Phase I of the project. The two preceding tasks involved selecting the site from a number of candidate USMC installations (the Site Selection task) and characterizing the site (the Site Characterization task). Data gathered during the site characterization visits to Quantico, together with information on industry experience from the literature, were used as the basis for this assessment.

1.1 APPROACH

The original objective of this value-impact study was to quantitatively assess opportunities for improvement at the CHP that were identified in the Central Heating Plant Site Characterization Report (SCR) (Pacific Northwest Laboratory 1990). However, sufficient data were not available to establish a CHP performance baseline. The performance baseline would quantitatively characterize the present efficiency, costs, reliability, and other operating conditions of the CHP. Without a baseline, performance improvements cannot be measured and are difficult to estimate. Therefore, only a qualitative study was done at this time. Consequently, this value-impact report can be used only to guide project decisions and help judge their potential impacts.

Based on the site visits to Quantico, 12 major problems were identified. These 12 problems, displayed in Table 1.1, represent improvement opportunities and are discussed and analyzed in this report. These opportunities differ in complexity and involve a number of different areas of the physical plant. Implementation of the Decision Support System for Operation and Maintenance (DSSOM) will help solve a selected set of these problems. Which problems, and

TABLE 1.1. Major Quantico CHP Problems

1. Boiler efficiency is less than possible.
2. Boilers are not controlled adequately to minimize corrosion, stress, and damage.
3. Water chemistry is maintained inadequately.
4. Fuel handling and delivery systems are unreliable.
5. Ash handling system is unreliable.
6. Components are not adequately maintained.
7. Fuel is not selected to optimize plant economic performance.
8. Condensate return is lower than possible.
9. Load management is not optimal.
10. Plant staff and contractors work in unsafe situations.
11. Recordkeeping is inaccurate and incomplete.
12. Labor is not used as effectively or efficiently as possible.

the precise impacts their solutions will have, cannot be determined at this time because the DSSOM solution has not yet been defined. Therefore, the potential qualitative impacts are examined in this report, with supporting quantitative information provided where possible.

For each of the 12 problems, the potential economic, safety, and reliability impacts of solving the problem were examined and evaluated. The economic implications considered include the direct monetary costs at the CHP, such as the cost of fuel, water, chemicals, repairs, overtime labor, spare parts inventory, and equipment replacement. The safety impacts considered include the risk of accidental injury or death to onsite CHP and contractor personnel. The reliability assessments address the ability of the CHP to meet the steam load of the Quantico base. The reliability impacts do not have a direct economic or monetary effect on the CHP but, of course, may and probably do have such effects on the rest of Quantico. The monetary value of CHP steam to the rest of Quantico and the economic impacts of increased reliability were not determined in this study.

1.2 REPORT OVERVIEW

Section 2.0 contains brief descriptions of the major systems in the Quantico CHP (e.g., fuel supply system, boilers, and ash handling system). Further details of these systems are contained in the SCR report. Section 3.0 discusses each of the 12 major system problems separately. In each of these discussions, a brief description of the problem is followed by a presentation of the improvement opportunities associated with solving the problem. The impacts of each improvement opportunity on plant economics, safety, and reliability are discussed in this presentation. Section 4.0 presents the conclusions and recommendations obtained from this study.

2.0 FACILITY DESCRIPTION

The Quantico CHP provides steam to all users connected to the Quantico central steam distribution system. The base has 1,384 buildings in which over 14,000 people work during the daytime. The steam distribution system comprises 22 miles of steam lines. The distributed steam is used for space heating in buildings, in steam tables in mess halls, in the hospital, in air hangars, for an onsite laundry, and other applications. The total steam load varies from about 40,000 lb/h in the summer to 125,000 lb/h at times during the winter. During the summer, one boiler can meet the load; in winter, at least two boilers are required.

The plant is operated by approximately 30 staff members including plant administrators, operators, and maintenance staff. The knowledge and training of the staff varies widely.

The CHP (see Figure 2.1) consists of six boilers; two (Boiler Nos. 4 and 5) are condemned and inoperable. The remaining four boilers range in steam production capacity from 50,000 lb/h (Boiler Nos. 1 and 2) to 120,000 lb/h (Boiler No. 6). All of the operable boilers have been fitted to burn either pulverized coal or fuel oil.

Major systems in the plant include the following systems:

- feedwater
- condensate
- water purification
- chemical addition
- deaeration
- steam generation
- oil handling
- gas pilot
- coal handling
- ash handling
- emission control
- compressed air
- electrical
- control.

These systems are described in Section 4.0 and Appendix A of the SCR (Pacific Northwest Laboratory 1990).

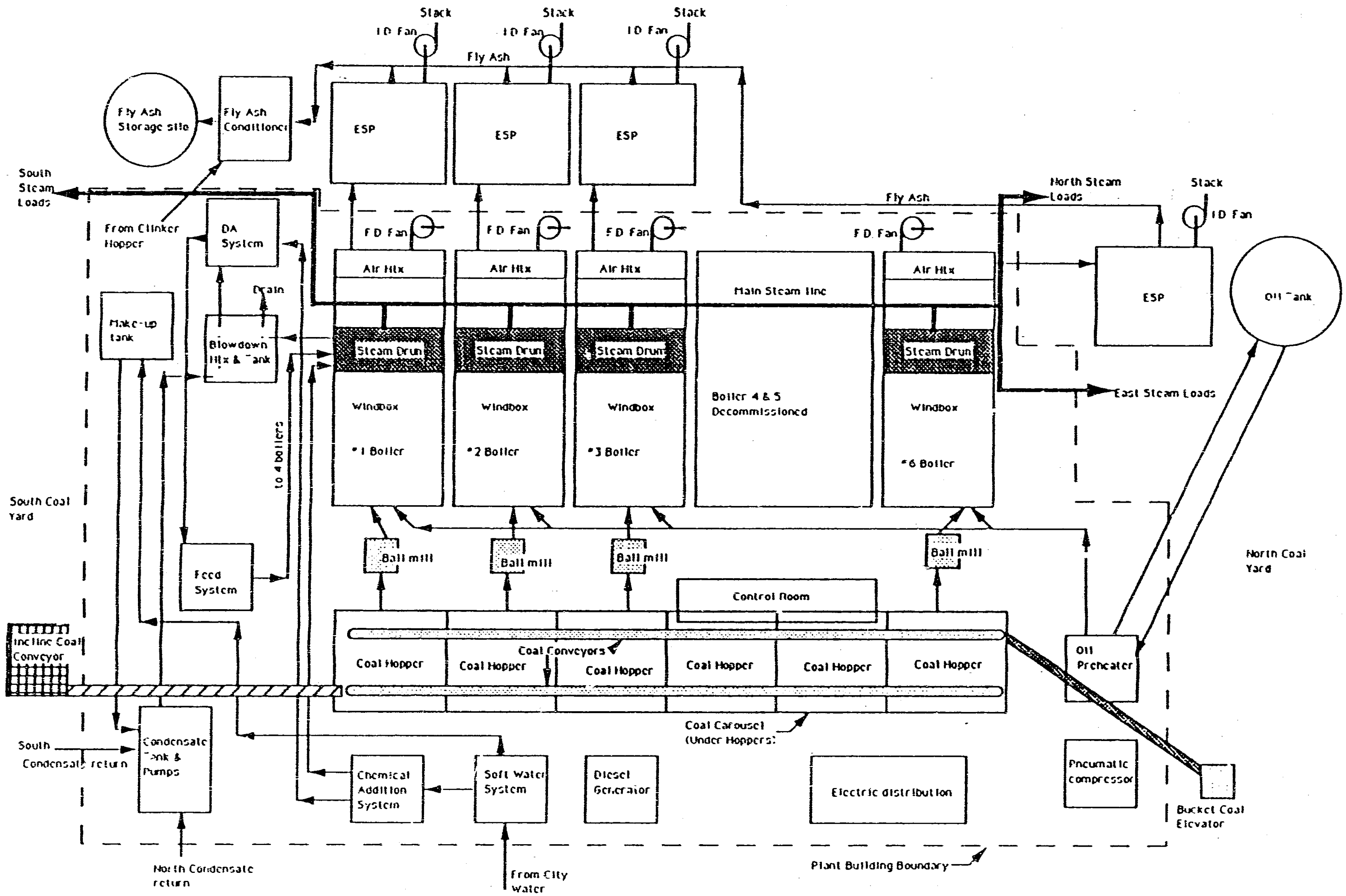

FIGURE 2.1. Plant Schematic

3.0 IMPROVEMENT OPPORTUNITIES

Opportunities for improvement to the Quantico Central Heating Plant are documented in this section. The opportunities stem from 12 major problems abstracted from observations and events documented earlier in the Site Characterization Report (Pacific Northwest Laboratory 1990).

In Sections 3.1 through 3.12, each of the problems is briefly described. The improvement opportunities associated with each problem are then discussed with respect to three principal areas of impact: economics, safety, and reliability (as appropriate for each problem). In Section 3.13, we briefly discuss interactions among improvement opportunities.

3.1 BOILER EFFICIENCY

The PNL team found that boiler efficiency at the plant is lower than possible.

3.1.1 Problem Description/Evidence

Boiler efficiency is key to an efficiently operating steam power plant. The efficiency of an individual boiler is the ratio of the energy actually used to produce steam (i.e., to raise the temperature of the feedwater to the boiling point and then vaporize the water) to the energy content of the fuel consumed by the boiler in producing that steam. Referring to Figure 3.1, the average boiler efficiency (η) over some time interval is given by the relation

$$\eta = \frac{m_{steam} \left(h_{steam} - h_{feedwater}\right)}{m_{fuel}\ HHV_{fuel}} \tag{3.1}$$

where m_{steam} = mass of steam produced during the selected time interval (e.g., in lbm)

m_{fuel} = mass of fuel consumed during the time interval (e.g., in lbm of coal)

h_{steam} = specific enthalpy of saturated steam at the steam drum pressure (e.g., in Btu/lbm)

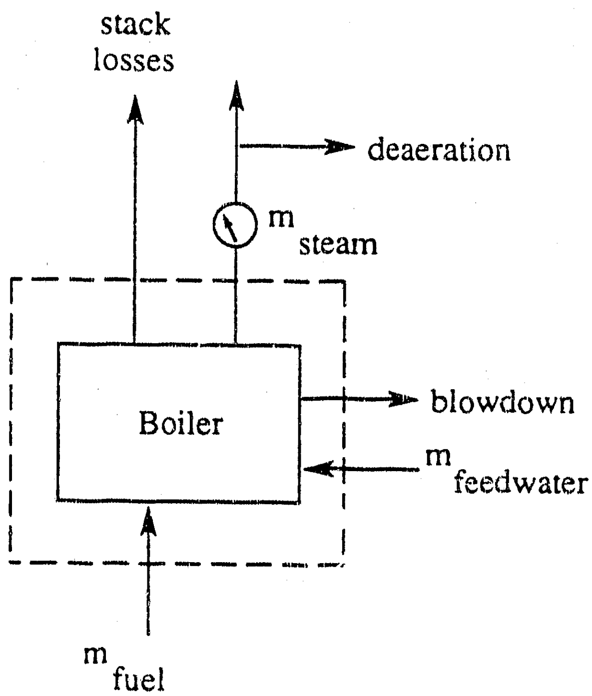

FIGURE 3.1. Mass Flows Into and Out of a Boiler

$h_{feedwater}$ = specific enthalpy of liquid water at the temperature of the feedwater entering the steam drum (e.g., in Btu/lbm)

HHV_{fuel} = higher heating value of the fuel (e.g., in Btu/lbm of coal).

Neither total cumulative steam production by the plant nor cumulative steam production by the individual boilers is currently measured and recorded at the Quantico CHP. However, once each hour, the plant operator records in the operator's log the steam flow rate for each boiler in operation. The operator determines the steam flow rate by multiplying the boiler capacity by the percentage of capacity shown on the control panel. This instantaneous measurement can be used as an estimate of m_{steam} for that hour. The steam production over several hours or for a day can be estimated by adding these instantaneous measurements.

Measured fuel consumption is recorded in the operator's log and can be used to determine m_{fuel}. For fuel oil, a reading is recorded once each hour in the operator's log. Therefore, by taking the difference between the fuel oil readings at the end and beginning of a period, the total amount of fuel oil consumed can be determined. Even if the reading is not recorded at the same time every hour (and, therefore, the time increments between readings are not precisely 1 hour) the error introduced should be relatively small over a several-hour time interval.

For coal, the scales are read during the first hour of each shift; the scales provide a measure of the cumulative coal input to the ball mills in pounds. The coal consumption during any specific shift can be determined by taking the difference between the reading at the beginning of the next shift and the reading at the beginning of the shift of interest. The coal consumed during a day can be determined similarly by using the readings at the beginning of each day.

Gas is used as fuel for the pilots in all boilers at the Quantico CHP. Gas meter readings are recorded during the first hour of each shift. As for coal, the total gas consumed can be estimated by taking the difference between readings at the beginning of two shifts. The energy content of the gas consumed during proper operation of the boilers at Quantico is so small (less than 1% of total CHP fuel consumption in fiscal year 1989 [FY89]) that it has a negligible impact on the estimated boiler efficiency and, therefore, can be neglected without introducing measurable errors.

The enthalpies of the feedwater and the steam are functions of temperature and pressure. When the boilers are operating properly, a steam pressure of approximately 120 psi is maintained. At this pressure, the specific enthalpy of the saturated steam produced, h_{steam}, is 1191 Btu/lbm (Van Wylen and Sonntag 1973). Feedwater delivered to the boiler from the deaerator is at approximately 240°F. The specific enthalpy of saturated liquid water at this temperature (which corresponds to a pressure of about 25 psi) is 208.5 Btu/lbm, which can be used as an estimate of $h_{feedwater}$. The actual feedwater pressure is not measured; however, enthalpy is very weakly dependent on pressure for liquid water, so that only negligible errors can result from not knowing the pressure.

The heating values of the fuels must be estimated. Fuel analyses giving the higher heating value (HHV) accompany each shipment of coal and are retained in plant files. The PNL team used the heating values from the last few coal shipments to estimate a value for HHV. For No. 6 fuel oil and natural gas, we have used the values provided by the Quantico CHP. The estimated heating values are displayed in Table 3.1.

Using data from the operator's log for selected days between August 19 and December 13, 1989, we estimated the daily efficiency of each boiler for each fuel burned. The results are displayed in Table 3.2.

Industry experience shows that the average efficiencies for industrial boilers of this approximate size are 83% to 87% for pulverized coal-fired boilers and 82% to 85% for No. 6 fuel oil fueled boilers. Maximum attainable efficiencies for these boilers are 89% to 90% (Payne 1989).

When comparing the calculated efficiencies to the maximum attainable efficiencies, in many cases, the boilers appear to operate very efficiently when burning coal (in some cases well above the maximum attainable efficiency). However, this is not consistent with the observed condition of the boilers. The PNL team observed significant slag on boiler tubes. In addition, boilers frequently tripped during operation, and stack gas temperatures well above the normal operating range were observed. These and other

TABLE 3.1. Estimated Heating Values of Fuels

Fuel	Higher Heating Value (HHV)
Coal	14,600 Btu/lbm
No. 6 Fuel Oil	149,700 Btu/gal
Natural Gas	1,031 Btu/SCF

TABLE 3.2. Calculated Boiler Efficiencies

Fuel	Boiler No.	Number of Days	Efficiency, %
Coal	1	5	87-95
	2	5	93-101
	3	5	70-87
	6	5	83-93
Oil	3	4	65-72

observed conditions tend to lower boiler efficiencies well below the maximum efficiency attainable. Therefore, it was concluded that the calculated values must be in error.

The greatest error in the estimated efficiencies is probably attributable to the estimate of the cumulative steam produced, m_{steam}, or errors in steam flow rate measurement. We have estimated m_{steam} from the values of steam production rate recorded once per hour. However, based on observations in the control room, the operators generally do not record the steam production rate during a trip when it is low; they concentrate on correcting the trip and monitoring the boiler as it comes back on line (as they should). Consequently, the hourly recordings overestimate the cumulative steam produced, leading to overestimates of the boiler efficiency. An overestimate of m_{steam} by 20% would result in a calculated efficiency of 90% (approximately the maximum attainable efficiency) for a boiler having an actual efficiency of 75% (well below the average).

The estimated efficiency of Boiler No. 3 (65% to 72%), is well below the average (83% to 87%) for oil-fired boilers of this size. These results are much closer to our expectations based on the observed condition of the plant. However, if trips occur just as frequently while burning oil as they do with coal (which we do not have data to confirm), these estimated efficiencies would also be concluded to be high, thus indicating an enormous potential for efficiency improvement.

Numerous other factors could contribute to errors in the calculated efficiencies. Any measurement that depends on a device that is not regularly calibrated is placed under suspicion. The fuel consumption, the pressure of the steam produced, and the temperature of the feedwater upon which these calculations depend could all be in error. The result is that no credible baseline efficiency for the individual boilers or the overall plant can be established upon which to base estimates of the potential for improvement; only speculation can be made.

3.1.2 Improvement Opportunities

This section focuses on the economic impacts of efficiency increases. Safety and reliability have no direct relation to plant efficiency and are not assessed in this section.

The current plant and boiler efficiencies cannot be established using available data. However, several observations at the Quantico plant lead us to estimate that a fuel savings of at least several percentages is possible through improved boiler operation, control, and maintenance:

- Excess air was controlled inconsistently, indicating that combustion and boiler temperature were not controlled carefully enough to maximize efficiency. Excess air is provided to ensure adequate combustion. A too-high excess air level reduces the effectiveness of heat transfer to the boiler tubes and increases stack losses. Operation at minimum excess air levels of 3% to 15% for oil firing and 20% to 30% for pulverized coal are typical (Payne 1989). For a stack gas temperature of 500°F, boiler efficiency increases by approximately 0.076% for each 1% decrease in excess air.

- Stack gas temperatures were above the value prescribed (approximately 600°F, according to one operator) for initiating soot blowing, indicating poor heat transfer to the boiler tubes and excessive heat loss with the stack gas. A high stack gas temperature indicates that less heat is being extracted before the gas is lost up the stack. For example, for a boiler operating with 20% excess air, each 40°F reduction in stack gas temperature results in a 1% increase in efficiency (Payne 1989).

- Excessive slag, which inhibits heat transfer from the hot gases in the boiler to the boiler tubes, was present on the tubes. This condition would contribute to high stack gas temperatures and might result from nonoptimal soot blowing practices. Other conditions that could contribute to fuel-side deposits include poor firing conditions (e.g., low excess air or improper burner adjustment), improper location of the soot blowers, improper fuel oil burning temperature (for oil firing), coal ash fouling properties, and improperly pulverized coal particle sizes from improper mill adjustments.

- The water level in the steam drum varied considerably, affecting the convective loop on the water side of the boiler tubes and, thus, decreasing heat transfer to the water and steam production. These variations also resulted in numerous boiler trips.

Correcting these problems by providing better real-time boiler control and periodically checking, adjusting, cleaning, and generally maintaining the boiler and auxiliary equipment would improve boiler efficiency and decrease fuel costs. The estimated potential annual savings on expenditures for fuel oil and coal, based on FY89 use, are displayed in Figures 3.2 and 3.3 (for initial boiler efficiencies of 60% and 75%, respectively), together with annual savings if only coal were burned. These estimates are based on FY89 fuel prices and do not account for expected increases in fuel prices in the future. The percentage increases in efficiency are expressed as a percentage of 100% rather than on the current efficiency, which is unknown. For example, if the current efficiency were 60% (see Figure 3.2), an 8% increase in efficiency to 68% would result in a savings of about $368,000/year on No. 6 fuel oil and $45,000/year on coal. If all coal were burned, an increase of 8% in the boiler efficiency would result in a savings of about $145,000/year.

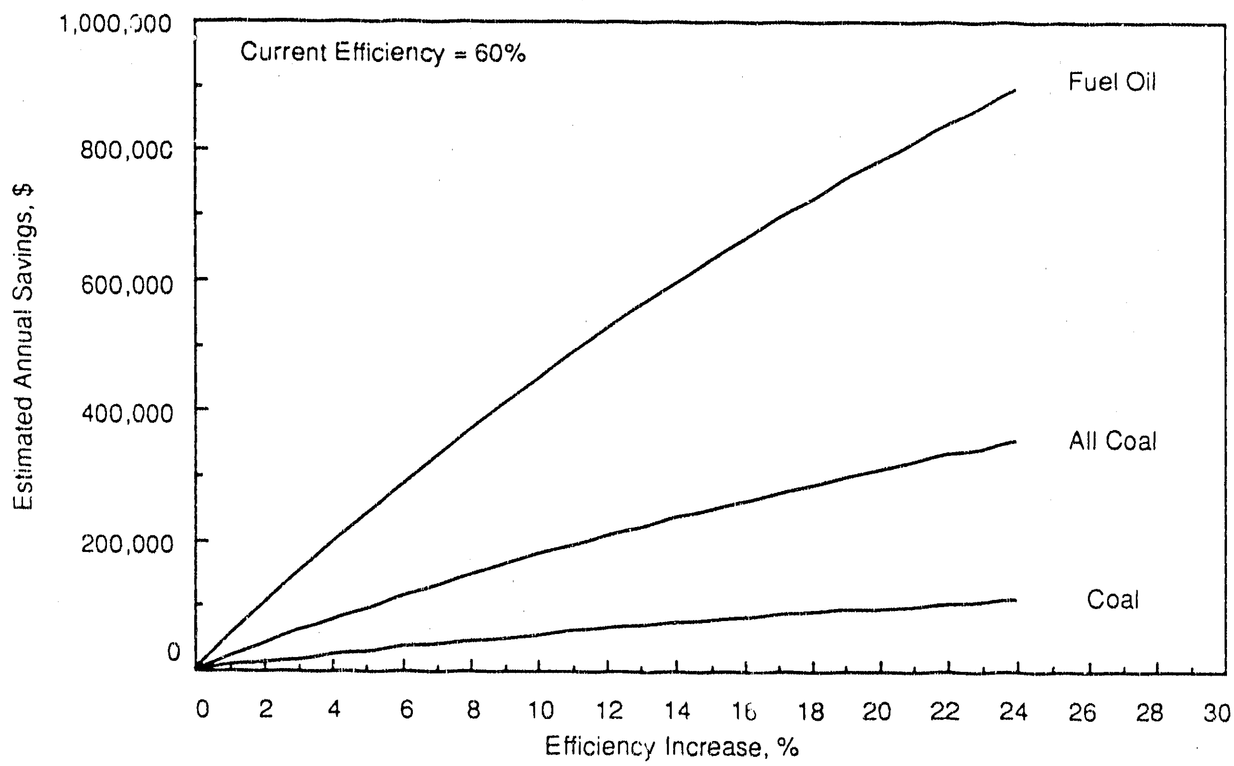

FIGURE 3.2. Estimated Annual Fuel Savings as a Function of Percentage Increase in Boiler Efficiency for an Initial Efficiency of 60%

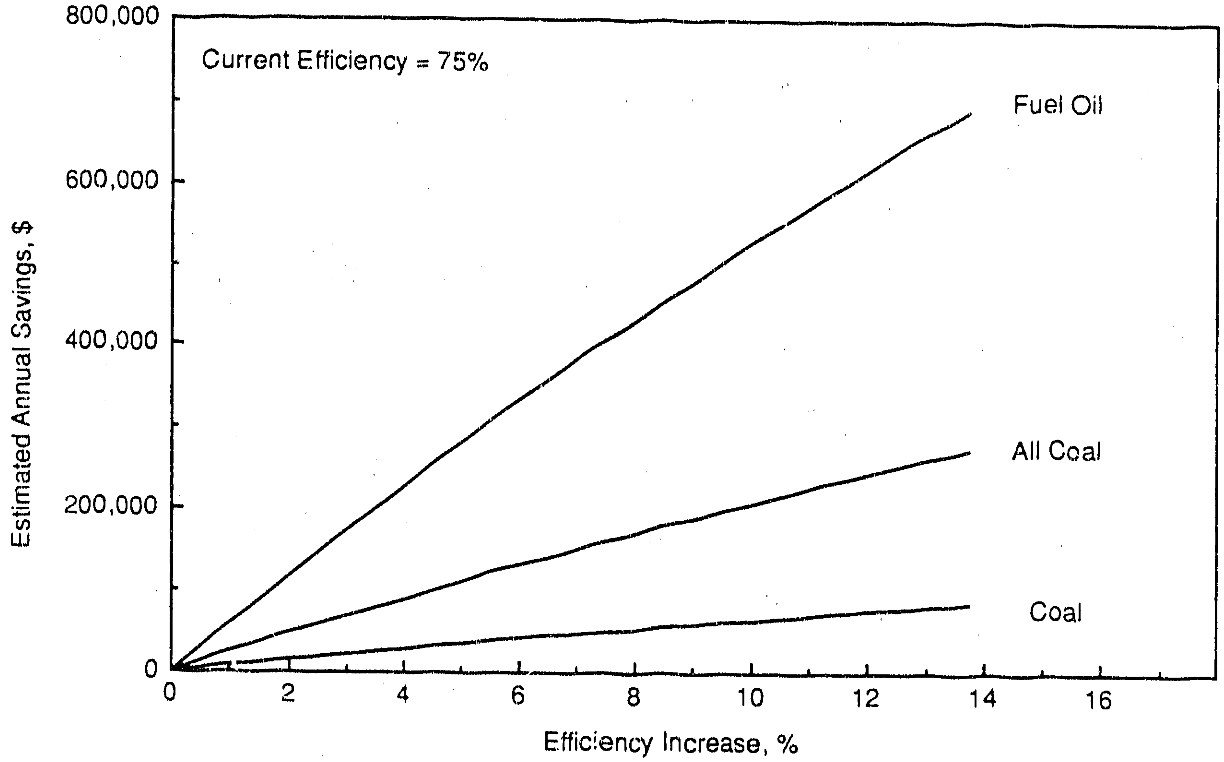

FIGURE 3.3. Estimated Annual Fuel Savings as a Function of Percentage Increase in Boiler Efficiency for an Initial Efficiency of 75%

3.2 BOILER CONTROL

Boiler corrosion and stress result from a number of physical phenomena and lead to shorter boiler lifetimes and lower thermal efficiencies. Stress is caused by thermal shock resulting from sudden large-temperature changes, thermal stress associated with the alternate heating and cooling of equipment (i.e., thermal cycling), mechanical stress, and pressure variations. Proper boiler control minimizes these sources of stress and leads to longer equipment lifetimes.

Stresses associated with equipment cycling can significantly reduce equipment lifetimes. The utility industry has experienced damaging residual stresses and plastic deformations in boilers from thermal shocks and accelerated creep from over-temperature excursions. This damage has been sufficient to reduce creep life by 50% (Schiebel 1985).

Of the various boiler components, the boiler tubes are the most susceptible to damage from corrosion. In the electric utility industry, tube failure is the most significant cause of plant unavailability (EPRI 1980). Corrosion can result from slag (molten ash) forming on the fire side of boiler tubes, which inhibits heat transfer as well. Corrosion on the water side of the boiler tubes results from improper water chemistry (see Section 3.3). In order of frequency of occurrence, the most prevalent tube failure mechanisms are 1) wall thinning by fireside erosion and corrosion, 2) water-side corrosion and hydrogen damage, 3) stress, and 4) overheating, which causes changes in tube metallurgy (EPRI 1980). Tube failures first appear as leaks, which may go undetected. Continued degradation of tubes can lead to catastrophic failure in which tubes melt; allowing the risk of a potential boiler explosion to exist.

Corrosion can also occur at the air preheater. Low temperatures at the exit of the air preheater can cause condensation of water vapor. Sulfur trioxide in stack gas combines with the moisture to form sulfuric acid, which attacks the preheater surfaces.

Fire-side corrosion from slag is generally associated with coal burning. Oil has a very low ash content, 0.2% or less, but can also present a significant corrosion problem (Babcock & Wilcox 1972, pp. 15-24). Liquid sulfates and vanadates in oil ash deposits cause fouling and corrosion (EPRI 1987). The presence of sodium greatly escalates the problem by decreasing the minimum metal temperature at which corrosion becomes significant (Babcock & Wilcox 1972, p. 15-23).

3.2.1 Problem Description/Evidence

Several observations by the PNL team during visits to the Quantico CHP indicate conditions that could lead to accelerated corrosion and stress:

- Frequent boiler trips thermally cycle the equipment and can produce thermal shock.
- Large variations in steam-drum level affect convective flow through the boiler tubes and present the danger of uncovering the tubes.

- Excess slag on the fire side of the boiler tubes indicates the potential for increased corrosion.

- Boiler No. 3 had a visible water leak.

3.2.2 Improvement Opportunities

Boiler corrosion and damage from improper control affects plant economics in three primary ways: 1) decreased efficiency resulting from heat transfer degradation, 2) higher component failure rates and correspondingly increased maintenance and repair costs, and 3) increased costs associated with more frequent equipment replacement (because of corrosion and stress) cause premature failure of components. Better control would lead to higher efficiency (and lower fuel costs), lower maintenance and repair costs, and longer equipment lifetimes.

Reliability is also affected by inadequate boiler control. As equipment degrades from excessive corrosion and stress, the reliability of the plant decreases more rapidly than ordinarily expected. In addition to being a direct indicator of poor operation, the frequency and severity of trips are obvious indicators of poor reliability. Another indicator of changes in reliability is the amount of unscheduled downtime for repairs and component replacements. Increases in downtime indicate a decrease in reliability of the boilers, even when the overall plant can meet the demand for steam. Accelerated degradation may eventually lead to boiler failures requiring major boiler refurbishment and, ultimately, to an inability to meet the demand for steam at Quantico.

In addition to affecting plant economics and reliability, inadequate boiler control has detrimental impacts on safety at the plant. More frequent boiler startups and shutdowns put plant staff at a greater risk. The probability of a problem occurring increases during transient operation. In the worst-case scenario (e.g., if the steam drum were to boil down and the boiler tubes became uncovered), the boiler tubes might melt, possibly causing the boiler to explode. The result of such a catastrophic failure could be injury to plant staff and possible deaths.

Improvements in boiler operation and control would have significant immediate impacts on all three areas of plant performance. Neglecting the need to improve plant control could lead to catastrophic problems ranging from significantly increased costs and insufficient steam supply to accidents causing injury or death of plant staff.

3.3 WATER CHEMISTRY

A boiler water treatment program should have the following three objectives (Wieman and Marks 1986):

- to prevent deposits and scale
- to control corrosion of metals
- to prevent boiler water carryover.

One of the top priorities of any feedwater treatment program should be to minimize makeup water demand (Neff 1986). Makeup water is the source of most of the impurities found in boiler systems today. If condensate return levels were higher, then the amount of makeup water needed would be less.

3.3.1 Problem Description/Evidence

The PNL team found that the CHP water chemistry is inadequately maintained. They observed that the boiler water chemistry varied both above and below the specified operating ranges. In addition, on some days the water chemistry was not checked or recorded at all. Unless the state of the water is consistently identified and recorded, there is no way to effectively meet the three objectives of the water treatment program.

Scale provides resistance to heat transfer between the hot gases and boiler water. Scale is deposited on the water side of the boiler tubes during the steam formation process. Suspended and dissolved solids precipitate out of the water to form scale. The boiler efficiency decreases when scale builds up. In addition to reduced efficiency, boiler tube failures may occur from increased tube metal temperature in the scale area. Tube failure may occur before any noticeable effect on boiler efficiency (Payne 1986). Water hardness, or more specifically calcium and magnesium content, is primarily responsible for scale formation (Wieman and Marks 1986).

To control scale formation in the CHP boilers, the following steps are taken (Boiler Efficiency Institute 1985):

- A water softener is used to remove most of the hardness in the makeup water.
- Phosphates are added to precipitate any hardness not removed by the softener.
- A conditioner or polymer dispersant is added to prevent the phosphate precipitate from sticking to the tube walls.
- Continuous and bottom blowdowns are used to remove solids and other waste products from the boilers.

The use of both a phosphate and a polymer dispersant, such as polymethacrylate, is common in industry because of the high performance and low cost of such a blended chemical treatment system (Strauss, Keen, and Puckorius 1987). The boiler internals, including tubes, should be inspected annually for scale and other deposits (Thomas 1980). If necessary, water pretreatment practices should be altered to minimize the amount of scale in the feedwater.

The major contributors to corrosion in boiler systems are high oxygen and low pH levels (Strauss, Keen, and Puckorius 1987). Corrosive oxygen can enter the boiler system in the makeup water, through air leakage into the condensate return system, and by raw water contamination of the condensate (Peters 1980). The control of oxygen in the CHP boilers is done in the deaeration system by heating and by adding a chemical scavenger, sulfite. To control corrosion in the condensate return system, neutralizing or film amines are added in the steam drum. The amines neutralize the pH of the system to prevent acidic corrosion of the condensate return lines (Herman and Gelosa 1973). If the pH of the condensate is not controlled properly, then leaking condensate return lines will lead to a loss of condensate returned, which, in turn, results in lost energy and cost increases for makeup water and chemicals.

Prevention of boiler water carryover is the final objective of the water treatment program. Carryover is a condition in which water is carried from the boiler, along with steam, into the steam distribution system. Carryover reduces the quality of steam produced. It also could lead to deposits and scale in the distribution system, which can cause plugged steam valves and traps (Gelosa and Andrade 1976).

Carryover of water and solids can be caused by both mechanical and chemical problems. According to Herman and Gelosa (1973), the mechanical causes of carryover include

- sudden and excessive load fluctuations
- operation above rated capacity
- high water level in the steam drum
- defects in the steam separating devices; e.g., leaks.

To counteract these problems, Gelosa and Andrade (1976) suggest

- scheduling loads to avoid fluctuations
- installing automatic feedwater regulators
- checking steam purifying devices for defects
- adding an accumulator for intermittent excessive loading
- installing additional boilers if excessive loading is constant.

The chemical causes of carryover all lead to foaming, the most common carryover mechanism (Strauss, Keen, and Puckorius 1987). The most common causes of foaming are excessive alkalinity, presence of oil or other organic matter, and excessive concentrations of suspended solids, dissolved solids, and silica. In addition to keeping the water neutral and using blowdowns to reduce solid buildup, an antifoaming agent is commonly used. The inadequate maintenance of CHP boiler water chemistry greatly increases the risks of experiencing these problems.

The PNL team also observed that the blowdown system was running on boilers that were shut down. The water in the steam drum of shutdown boilers was being continuously removed. This excessive blowdown is a waste of water and chemicals (Neff 1986).

3.3.2 Improvement Opportunities

Inadequately maintaining and operating the water treatment system at the CHP has economic, reliability, and safety impacts. These impacts, which would result if the water treatment system were run adequately, are discussed below.

A properly run water treatment program is a form of preventive maintenance (Datanet Engineering, Inc. 1985). The major economic savings are in the following areas:

- energy costs
- maintenance labor and repair requirements
- deferment of capital equipment replacement.

Reducing scaling and controlling corrosion-caused leakage would reduce energy costs by increasing boiler operating efficiencies. The cost of maintenance labor and repair would also decrease if boiler tube and other failures caused by component corrosion were reduced. Also, by reducing corrosion, equipment lifetime can be increased. Excessive blowdown on nonoperating boilers is clearly a waste of money for chemicals and makeup water, and changing this operating procedure would reduce costs.

When these problems cause the boilers to be placed out of service at the CHP, the CHP becomes a less reliable source of steam for Quantico. Excessive downtime for maintenance, repair, and boiler component or condensate line replacement because of failures caused by scale and corrosion has a direct impact on the reliability of the CHP.

In the most severe case, the catastrophic failure of the boiler and its components poses an increased safety risk to plant personnel. By properly maintaining water chemistry, this risk is reduced.

In the CHP water treatment program, good operating practices, accurate control tests, quick adjustment for changing conditions, and alert investigation and correction of malfunctioning equipment are important to achieve the efficiency opportunities discussed above (Thomas 1980). Constant attention to the water treatment program needs to be a priority to ensure that these opportunities are taken advantage of. The damage caused during several weeks of poor water treatment practice cannot be undone during the remainder of the year.

3.4 FUEL HANDLING SYSTEM

The fuel handling and delivery systems at the CHP are unreliable. Both coal and oil are used as primary fuels. Natural gas is used only for ignition pilots and accounts for a small fraction of the total fuel consumed at the plant. Coal is stored and delivered from coal yards at the north and south ends of the plant. A bucket elevator transports the coal from the north coal yard to horizontal conveyors that distribute the coal to the coal hoppers (see Figure 2.1). Coal from the south coal yard is transported by an inclined conveyor system to the horizontal conveyors above the coal hoppers. Coal from the hoppers is transferred by a carousel conveyor to the appropriate ball mill (one ball mill serves each boiler with the exception of Boiler No. 6, which is served by two ball mills). The pulverized coal from the ball mills is then blown into the combustion chamber where it is burned.

Fuel oil is stored in a million-gallon tank next to the north coal yard. Steam passing through a heat exchanger in the tank maintains the oil at a minimum temperature and corresponding viscosity for pumping. Oil is pumped from the tank to preheaters inside the plant. The oil is heated to the desired temperature and pumped to the boilers where it is atomized with steam and injected into the boilers. Adequate oil temperature and pressure must be maintained for proper atomization. If either the temperature or pressure decreases below minimum levels, the boiler will trip.

3.4.1 Problem Description/Evidence

Several observations by the PNL team suggest that the fuel handling and delivery systems at the plant are unreliable.

- Coal spills off and accumulates around the conveyor in the south coal yard, binding the conveyor when enough coal accumulates at points of transfer from one conveyor to another.
- Coal accumulates under the horizontal conveyors above the coal hoppers, overloading the conveyor motors and causing fuses to blow.
- The current operating procedure is to run the coal conveyors until they bind.
- During winter months, at times, wet coal adheres to the walls of the weigher, preventing adequate coal from being fed to the burners.
- Failures of the lines that provide steam to preheat the fuel oil result in inadequate oil pressure to operate the oil burners and cause boiler trips.

These observed events indicate that 1) more labor hours are required to keep the coal delivery system operational than are currently allocated, 2) failures of the fuel supply systems can cause boiler trips, 3) the current practice of operating until failure results in excessive wear on components of the fuel delivery systems, and 4) inadequate coal delivery to the burners could result in low boiler capacity compared to rated capacity.

Keeping the conveyor system functional sometimes requires three or four maintenance and operations staff to leave their duties and shovel coal away from the conveyor, leaving one operator in the plant to maintain plant operations. This practice does not ensure safe, reliable plant operation.

Insufficient maintenance of both the coal and oil delivery systems puts the plant at risk of shutdown. During one site visit, the PNL team observed a boiler shutdown from an oil delivery system failure that resulted from an unrepaired leaky steam valve. More serious shutdowns are possible that could result in prolonged loss of steam until repairs are completed. For example, the practice of running coal conveyors until they bind could ultimately result in failure of the conveyor motors, which would prevent the coal from being burned. If the oil system were to then shut down, the whole plant could be forced to shut down.

3.4.2 Improvement Opportunities

The reliability of the fuel handling and delivery systems affects plant economics, reliability, and safety. The poor performance of the coal conveyor in the north coal yard results in increased labor costs to correct problems. Direct impacts result from excessive labor charges (e.g., the extra cost of overtime to correct failures at night or on weekends). The plant foreman even shovels coal at times, detracting from his supervisory responsibilities and increasing labor costs. And, a special vacuuming truck is needed periodically to vacuum coal fines off the conveyor system (at a cost of about $7200 in 1988).

Indirect economic impacts result from shortened equipment lifetimes and inefficient combustion. Equipment lifetimes are decreased by 1) excessive wear from the run-until-failure operating procedure, 2) inadequate maintenance of plant equipment because of maintenance staff devoting excessive amounts of time to keep fuel supply systems operational, and 3) stress and wear caused by excessive cycling resulting from boiler trips. More frequent than necessary replacement of component and auxiliary equipment increases the cost of keeping the plant operational. Fuel system degradation and failure can potentially lead to inefficient combustion and higher than necessary coal costs.

Boilers trips and the associated loss of steam pressure affect the reliability of the plant. Extended downtime and loss of pressure can shut down certain operations at Quantico (e.g., the laundry, which requires a minimum steam pressure to operate). Frequent boiler trips lead to the potential for the greater problem: plant shutdown and loss of steam service.

Safety is affected by the frequent trips caused by failure of the fuel supply systems. Boiler startups and shutdowns are more hazardous than the continuous operation of boilers. As a result, increasing the number of start-ups and shutdowns increases the safety risk for plant staff.

Correction of the conveyor problems alone would have a significant impact on the economics and reliability of the plant. Sufficient data are not available to quantitatively assess the impacts, but corrective action would free up plant maintenance and supervisory staff to perform their assigned functions, thus reducing direct labor costs of keeping fuel delivery systems operational and improving plant conditions.

Regular preventive and timely corrective maintenance of the fuel supply systems would reduce overall plant costs by extending equipment lifetimes and improving efficiency. Proper maintenance would also improve plant safety and reliability by reducing the rate of equipment wear and keeping the systems operational.

3.5 ASH HANDLING SYSTEM

Combustion by-products are formed when coal is burned in the combustion chamber. One such by-product, bottom ash, is composed of large ash particles and slag and is withdrawn from the ash hopper at the bottom of the boiler. The second combustion by-product, fly ash, is found in the exhaust air leaving the chamber. These two combustion by-products are handled by two different systems in the CHP until they are combined in the ash conditioning system. They are then transported by truck to an offsite landfill.

3.5.1 Problem Description/Evidence

The ash handling system at the CHP is unreliable. The first ash handling system transports bottom ash to the ash conditioning system. The bottom ash falls into the boiler ash hopper under the boilers and is then transported by pumping to the ash conditioning system. This pumping system has a common header extending beneath all the boiler ash hoppers. Three problems were identified with the bottom ash handling system. The first problem is that large pieces of slag fall across the hopper outlet, causing the hopper to fill, and thus preventing ash from leaving the boiler. To correct this problem, an operator must use a long iron rod to manually jar loose the slag that is causing the blockage. If the slag cannot be jarred loose, the boiler will continue to fill with bottom ash until it must be shut down; maintenance staff would then be called to correct the problem.

The second problem in the bottom ash handling system is in the common header or pipe beneath the boilers. This header is located in a ditch under the boilers; when rain or snow runoff accumulates in the ditch, water enters the ash transport pipe and a mixture of water and bottom ash is created. This mixture plugs the header, causing the bottom ash handling system to fail. Maintenance staff must then clear the header. In addition to causing a clogging problem, water in the ditch leads to increased corrosion problems in the header, requiring more repairs.

The third problem in the bottom ash handling system is that the wrong impellers are currently installed on the pump used to transfer bottom ash from the header to the ash conditioning system. The pump impellers eroded because they were designed for pumping pure water, not an abrasive mixture of water and ash. Replacement impellers were ordered, but either exact part numbers were not known or exact replacement parts were not available. The replacement impellers obtained could not be used, and reordering resulted in a lengthy downtime for the sump pumps. This problem results in the pumps working harder to meet suction requirements, thus accelerating wear on the pumps, and shortening pump lifespans.

In the fly ash handling system, the PNL team observed two problems. After exiting the boiler combustion chamber, the exhaust air enters the electro tatic precipitators (ESPs) where the fly ash is removed from the exhaust air stream. The fly ash is then conveyed to the ash conditioning system while the exhaust air is sent up the stack to the atmosphere. If a problem occurs in an ESP, a circuit breaker will trip and cause the ESP to shut down. The PNL team noted that an operator reset a circuit breaker for one ESP without recording the fact that it had been tripped. Also, the incident was apparently not reported to another operator or to maintenance personnel. No attempt was made to determine the reason for the ESP circuit tripping. It is likely that the ESP will be tripped offline again. When the ESP is offline, fly ash particles are not removed from the exhaust air, but are simply sent up the stack. Insufficient records of ESP operating problems make it impossible to correct them and establish long-term performance of the ESPs.

The second problem in the fly ash handling system occurs as part of the fly ash conditioning. Fly ash from the ash storage silo is sprayed with water and then dried in a rotary dryer before being placed in trucks for offsite disposal. The PNL team observed that, during rotary dryer operation, the concentration of fly ash in the air appeared very high in the enclosed dryer room. In addition, piles of ash were noted on the dryer room floor. This condition is a health hazard for all operating and maintenance personnel who enter and work in the room.

3.5.2 Improvement Opportunities

The unreliable ash handling systems have economic, reliability, and safety impacts. Each of these impacts presents an improvement opportunity.

The clogging problems in both the boiler hopper and the header require excessive operator and maintenance time for correction, which increases costs. Labor costs may be increased further if overtime is required to correct the problems. The corrosion of the header pipe also leads to a decreased pipe lifespan, an increase in costs for repairs, and eventually premature pipe replacement. The use of the unhardened impellers on the header pumps will cause accelerated wear of the pumps. This, in turn, will necessitate increased repairs and cause premature failure and replacement of the pumps. Not recording ESP problems could have two economic impacts. The cost of eventually repairing the problem may be higher because of the problem getting worse over time. The risk of incurring fines or plant shutdown because of discharging ash-laden exhaust is increased by improperly operating the ESP.

Decreasing boiler shutdown time to repair problems with the bottom ash handling systems would increase the reliability of the CHP. Solving the clogging problems of the bottom ash handling system would eliminate the need to periodically shut down one or more of the boilers for repairs.

The potential health and safety risk from fly ash in the drying room could be reduced if the areas where fly ash entered the room could be identified and plugged. Currently, anyone entering the room without a protective device risks inhaling fly ash.

3.6 COMPONENT MAINTENANCE

Components are not adequately maintained. Proper maintenance is required to keep the plant operating efficiently and to prevent early equipment and component failure.

3.6.1 Problem Description/Evidence

Several observations by the PNL team indicate that current Quantico CHP maintenance is inadequate. These include

- boiler trips caused by circuits shorting during instrument calibration
- inoperable, inaccurate, or inconsistent boiler instrumentation
- numerous steam and water leaks throughout the plant
- clogged oil burner nozzles
- equipment not being properly tagged when in need of repair or while undergoing repair

- no formal system to control the spare parts inventory
- spare parts storage area in disarray
- no formal maintenance procedures for equipment
- no formal maintenance training program for the CHP
- insufficient documentation of maintenance work.

These observations, documented more fully in the Site Characterization Report (Pacific Northwest Laboratory 1990), indicate that the CHP maintenance program is reactive and chaotic.

Some of the effects of improper maintenance include

- Plant personnel do not adequately know the state of the plant, leading to improper operation and maintenance.
- Frequent boiler trips occur because of improperly maintained equipment and instrumentation.
- Boilers function well below their maximum possible efficiencies.
- Equipment and components fail before their expected lifetimes.

Industrial maintenance is usually divided into the following three categories:

1. corrective maintenance; expressly used to repair equipment after it fails
2. preventive maintenance; a program of regularly scheduled equipment inspection and repair
3. predictive maintenance; a program involving early problem detection and correction or repair through use of sophisticated monitoring and diagnostic systems.

Corrective maintenance is the most reactive and rudimentary form of maintenance. Use of corrective maintenance alone allows relatively minor failures to become larger, more expensive, and perhaps catastrophic. The CHP is primarily operated using this maintenance practice.

Preventive maintenance is systematic and usually formalized. Regularly scheduled inspections of each critical piece of equipment and appropriate maintenance actions, based on the inspection results, prevent or eliminate many problems before they shut down operations. Preventive maintenance tasks should be equipment specific and based on manufacturers' recommendations, established guidelines or codes, or operator/maintenance personnel experience (Petrocelly 1989).

The CHP is now performing annual inspections and preventive maintenance during the summer months. This maintenance had not yet been formalized in 1985 (Boiler Efficiency Institute 1985) and appears informal today. In addition, some preventive maintenance tasks should be performed on a daily, weekly, and monthly basis as well as on an annual basis. These tasks are currently being put in practice, but without an adequate method of documenting and tracking maintenance. Few formal procedures or records of maintenance task verification are kept at the CHP.

More important than the regular lubrication, spare parts availability, and inspection tasks of a preventive maintenance program is the knowledge of each major piece of equipment and its operation. This can be achieved only through proper training of maintenance and operations personnel (Carrieri 1983). The success of any preventive maintenance program depends on the knowledge of the personnel involved and their familiarity with the equipment (Petrocelly 1989). There are many examples of successful preventive maintenance programs in industry today. Most of them use computers to maintain consistent and efficient operations for plants that use expensive, complex equipment. The maintenance demands for such equipment today have led to the need for computerized systems to provide economic and efficient preventive maintenance (McGuirk 1977). The use of a computerized system for preventive maintenance provides the flexibility needed to meet changing circumstances and experiences, as well as facilitating the scheduling of inspections and repairs (Corcoran and Richards 1983).

The last, most complex, and most proactive of all maintenance practices is predictive maintenance. Predictive maintenance relies on the use of online performance monitoring to detect changes in the behavior or performance of specific components. One computerized approach to problem detection is to automatically compare monitored conditions to an established baseline of conditions, thus identifying optimal maintenance times. Many such systems are now in use by utilities across the United States with very favorable results (Moore 1988).

In 1983, a study for the electric power industry indicated that costs for corrective maintenance were 30% to 60% higher than the cost of preventive maintenance and 89% to 157% greater than the cost of predictive maintenance (Rosen 1989). Although these results may not apply directly to medium-sized steam power plants, they illustrate that significant cost reductions are possible by detecting and correcting problems before they become serious.

3.6.2 Improvement Opportunities

Improving the maintenance of the Quantico CHP should provide beneficial economic, reliability, and safety impacts. Each of these impacts is discussed separately below.

Proper maintenance of the systems and equipment at the Quantico CHP will enable better control by plant operators, leading to increased efficiency and reduced fuel costs. Optimal control of combustion and steam production requires reliable, accurate instrumentation and controls. This is possible only with proper calibration and maintenance.

Adequately maintaining the equipment at the CHP should significantly increase the mean time between equipment failures, thus increasing equipment lifetimes while reducing replacement costs. Better control of the spare parts inventory would also aid in this effort by ensuring that the correct parts are on hand when the equipment is scheduled for repair work. In general, better management of maintenance would lead to more efficient and effective plant management at a lower total cost.

The adequate maintenance of CHP equipment will lead to less downtime for unscheduled maintenance, repair, and replacement. In addition, the total number of unscheduled outages and trips will be reduced. Both of these will result in the CHP becoming a more reliable supplier of steam to Quantico.

Efficiently maintained CHP equipment will also reduce the safety risk faced by plant personnel from steam leaks, water leaks, fire hazards, fly ash dust, and boiler explosion. Equipment will function properly, allowing improved plant control. Fewer leaks will occur, which present potential risks, and the frequency of boiler startups and shutdowns, when risks are greater than during steady-state operation, should be reduced.

To achieve these benefits, CHP management and staff must become committed to the objectives of the maintenance program. Adequate funding must be provided to correct existing problems. Individual plant personnel are relied on to implement improved maintenance procedures. Motivating staff and obtaining their commitment requires an appropriate administrative structure. Components of effective management (Hennebert et al. 1985) include

- constant two-way communication between management and staff
- fair and consistent treatment of personnel
- recognition for jobs well done.

Without the support of all the individuals in the plant, the best maintenance systems and program cannot succeed.

3.7 FUEL SELECTION

Fuel is not selected to optimize economic performance of the CHP.

3.7.1 Problem Description/Evidence

During FY89, coal represented 31% of the fuel used at the Quantico CHP (based on energy content of the fuel consumed); oil represented the other 69%. The amount of natural gas consumed at the plant by the ignition pilots was negligible (less than 1%) when compared to coal and oil consumption. Coal and oil consumption and estimates of costs, based on FY89 prices, are summarized in Table 3.3.

TABLE 3.3. Fuel Consumption and Costs, Fiscal Year 1989

Fuel Type	FY89 Consumption	Energy Content, 10^6 Btu	Unit Cost $/unit	Unit Cost $/$10^6$ Btu	Total Cost, $
No. 6 Fuel Oil	3,130,955/gal	468,704	0.55/gal	3.67	1,722,125
Coal	7,143/ton	208,576	53.11/ton	1.82	379,365
Combined	--	677,280	--	--	2,101,490

3.7.2 Improvement Opportunities

The cost of oil per unit of energy content is approximately double the cost of coal. Therefore, switching from oil to coal would result in a significant savings. Figure 3.4 displays total energy costs as a function of coal use, based on FY89 total fuel consumption. The cross represents the actual situation in FY89. Switching to 100% coal usage would produce a savings of about $900,000 (43%) annually. The potential savings would increase as steam demand or fuel oil prices increased. These estimates do not account for any differences in conversion efficiency because the actual efficiencies of the boilers at Quantico are not currently known (see Section 3.1). The actual savings would also depend on the relative efficiency of steam production with oil.

Under proper operating conditions, burning more coal should have only minor impacts on safety and reliability. If coal deliveries are less reliable than oil (no evidence indicates that this is the case), oil would be required

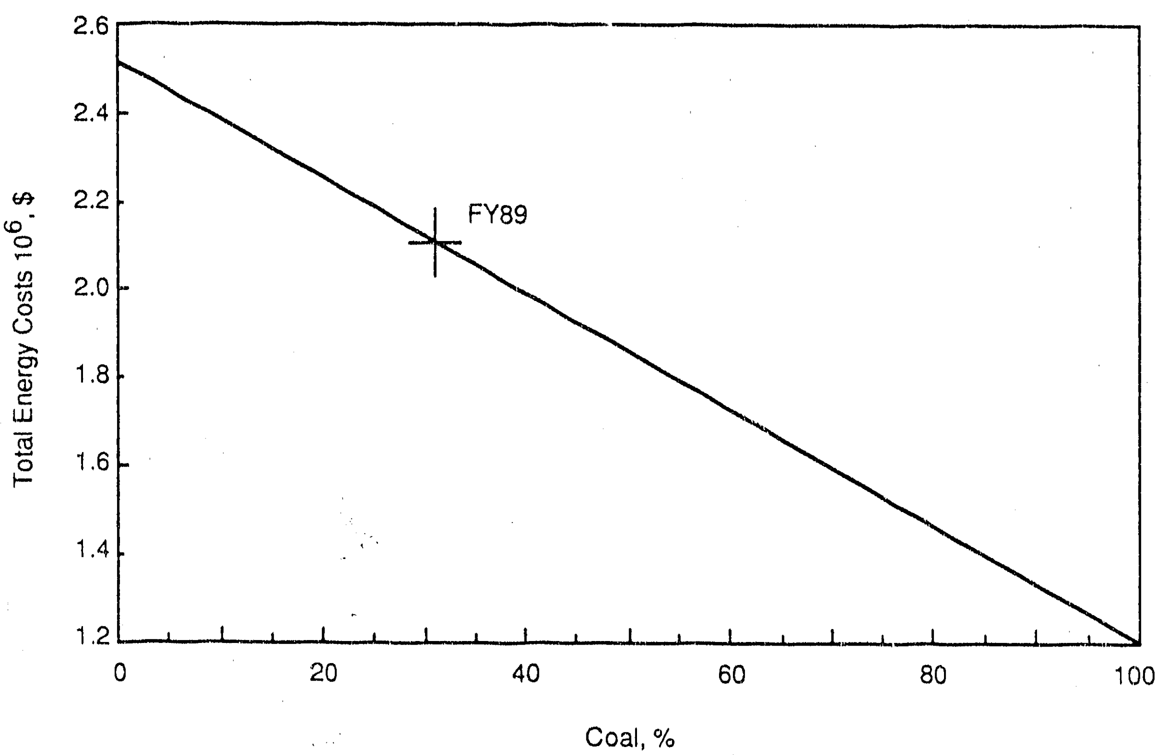

FIGURE 3.4. Fuel Costs as a Function of Coal Use

whenever coal was not available. This should have no effect on either steam availability or plant reliability. If the boilers operate more reliably on one fuel than on the other, plant reliability could be affected by the choice of one fuel over the other. However, if equipment is properly installed and maintained, the effect of using either oil or coal should be small.

Fuel choice could have some effect on worker safety, if burning coal is intrinsically riskier than burning oil. For proper operation, these differences in risks should be small. The principal differences are associated with coal and ash handling. Coal generally requires more equipment (e.g., ball mills, electrostatic precipitators) and greater labor and therefore involves more risk. But if the plant is properly maintained and operated and safe practices are followed, these safety differences should be small when compared to the savings resulting from greater coal use.

3.8 CONDENSATE RETURN

Steam produced in the CHP is distributed throughout the base to serve various needs including home heating, mess hall uses, hospital needs, laundry facility needs, and heating of aircraft hangers. After satisfying the various loads, the condensed steam (i.e., condensate) is returned to the CHP for reuse in the boilers.

3.8.1 Problem Description/Evidence

Condensate return is lower than possible at the CHP. Not all of the steam is recovered in the form of condensate and reused. Steam is lost via traps and distribution line leaks and leaks in the condensate lines themselves.

To make up for these losses, water must be added at the CHP before it is fed into the boiler. This makeup water is purchased from the city and must be chemically treated at the CHP to control scale and corrosion. The condensate is much like pure distilled water and does not require the chemical treatment that makeup water does (Peters and Ku 1983). Thus, when more condensate is returned, less chemical treatment is required, and makeup water and chemical costs decrease.

Table 3.4 displays monthly condensate return data for the CHP for FY89. The percentage of condensate returned (displayed in the far right-hand column of Table 3.4) is given by the relation

$$\text{Condensate Return (\%)} = 100\% - \frac{\text{Makeup Water}}{\text{Gross Steam Produced}} + 4\% \tag{3.2}$$

The 4% in Equation (3.2) is the estimated amount of water lost in the plant before steam is generated, expressed as a fraction of the gross steam produced. Most of the water is lost through boiler blowdown, but some is also lost by leaks and other minor plant uses. Actual steam production is not measured at the CHP; the foreman estimates gross steam production from coal and oil consumption, assuming a constant amount of steam is produced per unit of coal or oil consumed (e.g., in lb of steam/lb of coal).

TABLE 3.4. Quantico CHP Condensate Return Data, Fiscal Year 1989

Date	Makeup Water 10^6 gal	Gross Steam Produced 10^6 lb	Gross Steam Produced 10^6 gal	Condensate Return, %
10/88	3.4	43	5.16	38
11/88	4.5	61	7.31	42
12/88	6.2	77	9.23	37
1/89	6.6	74	8.87	30
2/89	6.2	73	8.75	33
3/89	5.3	75	8.99	45
4/89	1.9	41	4.92	65
5/89	2.1	33	3.96	51
6/89	2.3	27	3.24	33
7/89	2.0	26	3.12	40
8/89	2.2	27	3.24	36
9/89	2.3	28	3.36	36
Totals	45.0		70.15	

Condensate return varied from a high of 65% in April to a low of 30% in January. For the entire year,

$$\text{FY89 Condensate Return} = 100\% - \left(\frac{45.0}{70.15}\right) + 4\% = 39.85 \approx 40\% \qquad (3.3)$$

The plant foreman stated that the condensate return has been as high as 80% and that this could be sustained if the existing steam distribution and condensate return systems were repaired and properly maintained.

3.8.2 Improvement Opportunities

No apparent safety or reliability improvements would result from increasing the amount of condensate returned. However, there is a definite and quantifiable economic opportunity.

If the amount of condensate return doubled from 40% to 80%, then the amount of makeup water needed would be about halved. This would reduce the cost of city water and chemicals needed to treat the water to about half also.

The price of city water for the CHP in FY89 was $1.24 per thousand gallons, and the price of treatment chemicals in FY89 was $0.52 per thousand gallons of makeup water. As displayed in Table 3.4, 45 million gallons of makeup water were used in FY89, at a cost to the CHP of $79,200. Figure 3.5 displays the cost of water and treatment chemicals as a function of the percentage of condensate return. The cost ranges from ~$17,300 at 90% return to ~$116,000 at 10% return. Increasing condensate return from the present 40% to 80% would result in a savings of $49,600 ($79,200 - $29,632) at current water and chemical prices. As water and chemical costs increase, the savings from greater condensate return will also increase.

Large, old facilities, such as universities, usually have condensate return rates of 75% to 95% (Neff 1986). In smaller, well maintained buildings, the return rate may be above 95%. System losses should be less than 10% for a steam heating system that does not use steam for humidification, heating water, or other consumptive uses. Some general guidelines to reduce makeup water requirements include

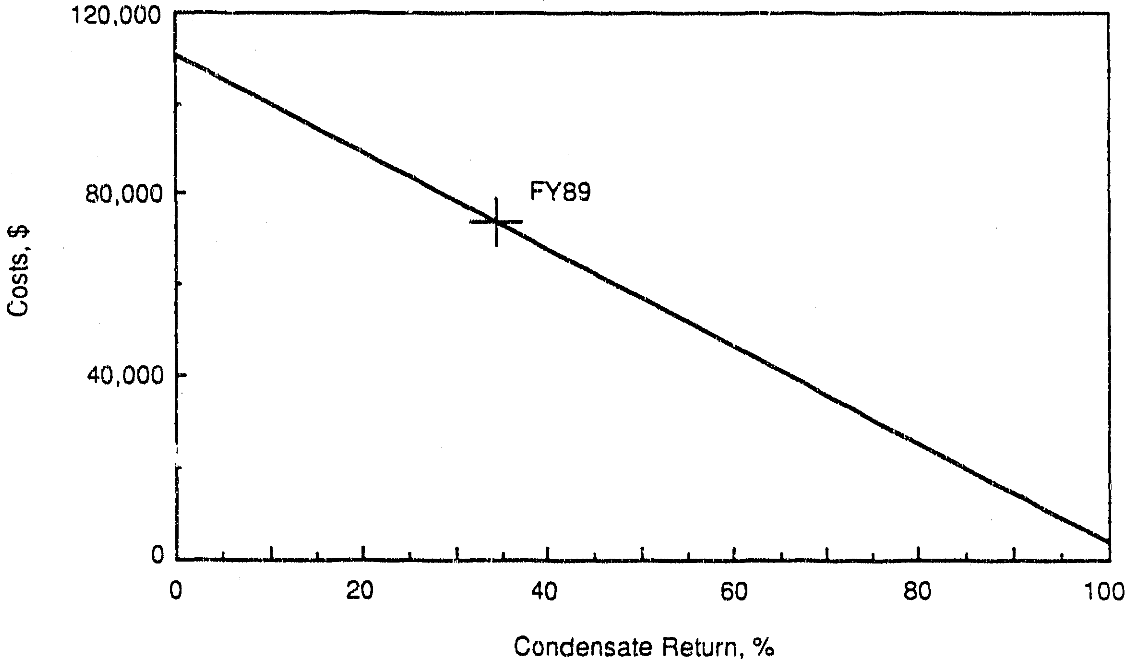

FIGURE 3.5. Makeup Water and Chemical Costs as a Function of Condensate Return

- Do not discharge any condensate to sewers; try to return all condensate to the boiler plant.
- Routinely inspect and immediately repair all leaking components of the steam distribution system including valve stems, pump seals, and relief valves.
- Maintain and frequently test steam traps.

Based on the information in this section, the Quantico CHP should be able to save approximately $50,000 per year on water and chemical costs by increasing condensate return.

3.9 LOAD MANAGEMENT

When more than one boiler is available to meet steam demand, the distribution of the load among the boilers affects overall efficiency. To minimize fuel consumption and maximize plant performance, the load distribution must be optimized.

The efficiency of a boiler generally varies with the rate at which it produces steam (Payne 1989). The efficiency curves for two hypothetical boilers displayed in Figure 3.6 illustrate this phenomenon. When both boilers are used, a particular distribution of the total load between the boilers results in the maximum overall efficiency. This is illustrated in the example that follows.

Assume that the two boilers characterized in Figure 3.6 both burn coal and have capacities (100% loads) of 50,000 lb of steam/h. For steam demands of less than 42,500 lb/h (85% of the capacity of Boiler No. 1), use of Boiler A alone would maximize efficiency because its efficiency clearly exceeds that of Boiler B. For larger loads up to 50,000 lb/h, some combination of the boilers may provide a greater overall efficiency. Above 50,000 lb/h, both boilers are required just to meet the load (actually, both

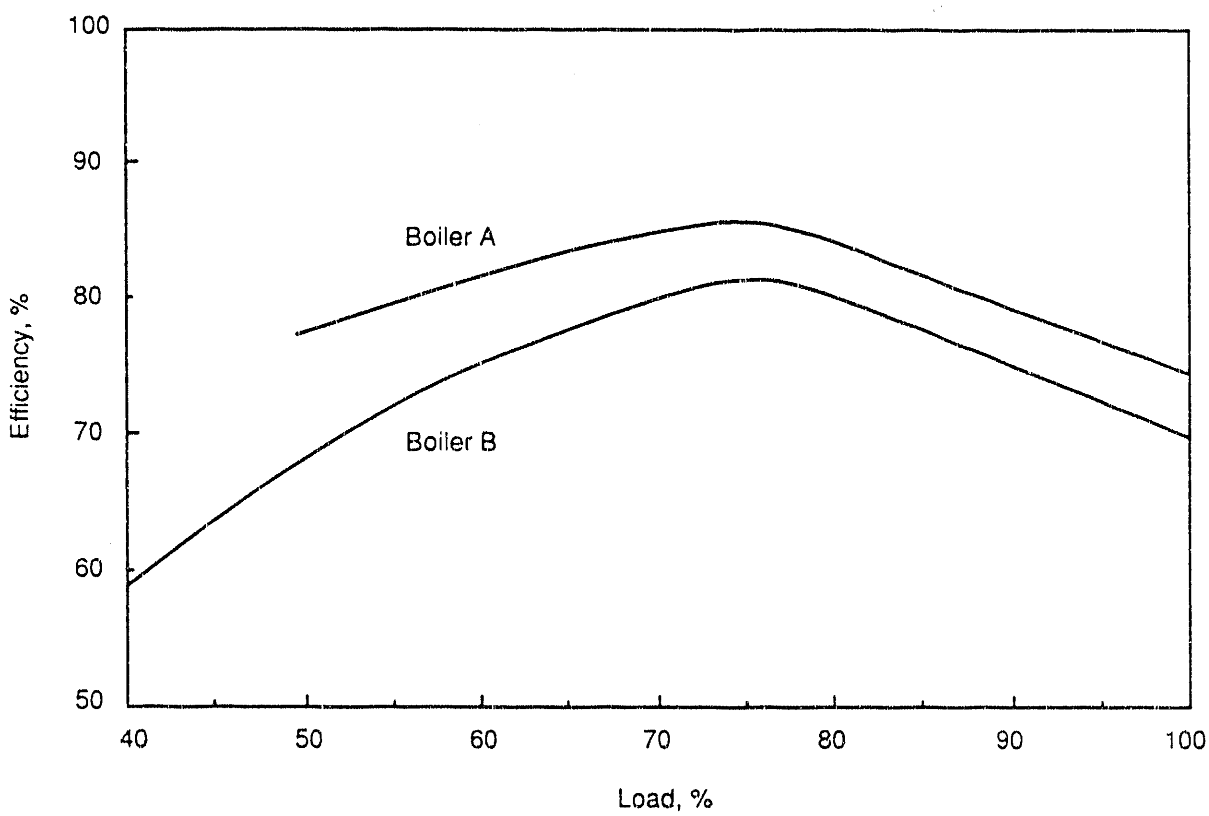

FIGURE 3.6. Efficiency as a Function of Load for Two Hypothetical Boilers

boilers would probably be used sooner because boilers ordinarily are not operated close to 100% capacity for reasons other than efficiency), but some specific combinations do maximize overall efficiency.

Consider, for example, a total load of 60,000 lb/h. This load can be met in many possible ways, two of which are displayed in Table 3.5. The fuel consumption for Scenario 2 (when Boiler A operates at 60% load and Boiler B operates at 60% load) is about 9% lower than for Scenario 1 (when Boiler A operates at 80% load and Boiler B operates at 40% load), a significant improvement in efficiency.

3.9.1 Problem Description/Evidence

The load is not optimally managed at the Quantico CHP. During one of the site characterization visits to the CHP, the PNL team observed one boiler operating at 75% of capacity while another operated at 40% of capacity. Because curves of boiler efficiency versus load for the CHP boilers are not available at the plant, proper assessment of the load distribution has not been achieved, and the plant operators do not have the information necessary to adequately maximize plant performance.

TABLE 3.5. The Impact of Load Management on Fuel Consumption

Scenario	Boiler	Load, %	Efficiency, %	Coal Used, lb/h[a]
1	A	80	82	3365
	B	40	58	2321
	Total			5686
2	A	60	81.5	2477
	B	60	75	2692
	Total			5169

(a) Estimated using an enthalpy change of 982.5 Btu/lb of water and a heating value of 14,600 Btu/lb for coal.

3.9.2 Improvement Opportunities

Information on boiler performance as a function of load and the analytical capability necessary to determine the optimum distribution of load among available boilers would allow the Quantico plant operators to improve plant performance. In addition to assessing plant efficiency (as in the example), by accounting for differences in fuel prices, total fuel costs could be minimized. Total fuel costs in FY89 were about $2.7 million. If by managing the load better fuel costs were reduced by 5%, the plant would save $135,000 annually.

Better load management should have a negligible effect on plant safety and reliability. If one boiler is inherently more reliable or safer than another, this could be factored into decisions concerning load distribution. However, these are secondary effects that are unassessable with the available data.

3.10 WORKING CONDITIONS

Safe operation of the CHP should be one of the most important goals toward which all plant personnel strive. However, the PNL team found several specific instances of unsafe working conditions and practices.

3.10.1 Problem Description/Evidence

Events and observations noted during visits by the PNL team indicate that the CHP is not being operated safely:

- When the north coal conveyor system shut down because coal binding the conveyor caused a fuse to blow, an operations person pulled out and replaced a 208-V fuse, twice, with his bare hands.
- When the same coal conveyor still did not start, an operations person began to jump on the conveyor, which was located 8 to 15 feet above a coal bunker.
- While contractor personnel were working in the firebox of one boiler, the forced-draft fan was turned on.
- Many components undergoing maintenance or out of commission were not tagged as such.

- Tools and spare parts were stored in disarray around various areas of the CHP.
- Bare wires were seen extending from electrical wall outlets.

These examples are only a small set of the safety problems noted at the CHP and are indicative of a lack of a safety-first attitude. Any one of these observed conditions could result in a serious accident that would affect the health and well-being of CHP personnel.

3.10.2 Improvement Opportunities

This problem, by definition, is only safety-related. Although safety does ultimately impact reliability and economics, as noted in Section 1.0, these impacts are indirect and are not addressed in this examination of the problem.

A totally safe operation can never be guaranteed; the best that can be hoped for is some degree of control to minimize the exposure to risk. One of the best ways to reduce risk is to implement a comprehensive safety program covering all aspects of CHP operations. This safety program should be unique to the CHP and account for procedures that involve the operation of the physical plant. There are many types of safety programs, but they all address the following broad categories: general safety, electrical safety, fire safety, security, and emergency operations (Petrocelly 1989).

Although safety programs are the most effective long-term means for ensuring safe CHP operations, the use of common sense in everyday situations will result in immediate benefits. Thoughtful vigilance will result in a safer operation; any lapse in safety concentration can result in an accident. To instill a safety-first attitude in all workers, a training program could be used to emphasize the importance of safety as a priority to CHP management. A safety program without the attendant training program might not yield many beneficial results. In addition, refresher safety courses covering specific aspects of safety should also be taught to keep all CHP personnel alert to potential safety hazards.

Thus, the implementation of a safety program and the associated continuous safety training should decrease the number of hazardous events at the CHP.

3.11 RECORDKEEPING

Some recordkeeping at the CHP is inaccurate and incomplete.

3.11.1 Problem Description/Evidence

The PNL team examined the following general types of records and found them to be either inaccurate or incomplete: operator logs, maintenance logs, and design (or "as-built") diagrams. Examples of each type of incomplete or inaccurate record are noted as follows.

The team found that the operator logs did not contain information regarding boiler trips (shutdowns) or other abnormal events that occurred on a shift, although the circular boiler chart did record the trips. Various steam leaks throughout the plant were seen by operating personnel but were not recorded in the operator log. When Boiler No. 3 tripped, the first-out light did not work. The status of this light was known among the plant personnel but was not documented. In addition, there were no records of valve locations to provide regulation of fluids. In general, the PNL team found that operators themselves decided what was to be recorded or not recorded. There was no standard procedure for entries into the operator's log.

A similar deficiency exists with respect to procedures for the maintenance logs and records. There appeared to be no tag-out procedures when components required or were undergoing repair. For example, when two workers were working in the firebox of one boiler, the operator on duty turned on the forced draft fan. The probability of this occurring would be reduced if proper tag-out procedures were followed. The PNL team also observed that many parts needed for maintenance work were not available because of a lack of proper spare parts and parts inventory control. Sometimes communication between the operators and maintenance personnel did not occur or was forgotten. In March 1989, a steam trap on a line used to heat the oil tank was not working, and the steam valve was shut off. Maintenance staff were not informed (or, if informed, did not repair the steam trap), and the valve was not tagged out. In December 1989 (9 months later), oil was needed in Boiler No. 3 but could not be pumped because of the low oil temperature. The steam valve was subsequently opened to heat the oil in the tanks, but instead, the steam vented into the atmosphere because the broken steam trap had not been repaired.

The "as-built" diagrams for the piping systems and new combustion control system were also found inaccurate and incomplete. Drawing nomenclature was not documented, and on some of the instrumentation diagrams, panel meters were shown that were not present on the actual panels.

3.11.2 Improvement Opportunities

Inaccurate and incomplete recordkeeping has economic, reliability, and safety impacts. Improvement opportunities in each of these areas are discussed below.

The operators' logs should document all events on each operating shift. This logbook should be a historical chronology of the plant's operations. Recorded equipment readings can be used to identify operating trends, trace temperature and pressure fluctuations, note tripping episodes, and indicate equipment status. The operators' logbooks should also alert relevant personnel--maintenance, management, and the next shift operator--to problems in the CHP that might otherwise go unnoticed or unreported (Petrocelly 1989). The use of an accurate, up-to-date operator's log is one way to ensure that the CHP is run as efficiently and therefore as economically as possible. The log serves not only as a historical record but also as a link from one shift operator to another and from the operators to the maintenance staff and management. By not recording leaks, trips, and other events, the problems are not repaired and will eventually cause further damage and more cost to the CHP. The CHP cannot operate at maximum capacity unless the operators' logs contain complete and accurate data on CHP operations. Maintenance cannot be performed efficiently if the maintenance records or logs do not accurately reflect the status of the CHP and the spare parts inventory is not known. The combustion control system is not being used effectively because as-built diagrams are not accurate and complete.

When operator and maintenance logs are not complete or accurate, the CHP is more likely to be unreliable. Trips occurred because operators' logs do not contain the correct or accurate data needed to diagnose problems as they occur. Problems causing the trip cannot be solved if data are unreliable or missing. The CHP cannot be properly maintained if maintenance records or spare parts inventories are lacking. The CHP reliability would be improved if maintenance staff could use the operators' logs as a diagnostic tool to help correct problems quickly and accurately.

If the status of the CHP and its associated equipment is unknown, safety problems can arise. Using inaccurate or incomplete records could lead to an accident, as nearly occurred in the firebox event noted above. Maintenance tag-outs are one of the most important means of preventing injuries to maintenance and operations personnel. Better communication is needed between maintenance and operations staff as well as between the various shifts at the CHP. Proper communication would reduce safety risks for all workers at the plant.

These opportunities are very general and based on only the few events and observations noted in Section 3.11.1. Even given this small set of observations, it can be seen that the impact of CHP recordkeeping spans all three areas of improvement opportunities--economic, reliability, and safety. Thus, improvements in recordkeeping will have far-reaching effects on CHP operations.

3.12 USE OF WORKFORCE

For the CHP to operate at peak efficiency, all resources need to be used effectively and efficiently. The workforce, such as that found in the operations, maintenance, and administrative staff, is such a resource.

3.12.1 Problem Description/Evidence

The PNL team observed that CHP workforce is not used as effectively or efficiently as possible. Some examples of the observed inefficient use of manpower include

- operators and maintenance personnel cleaning up coal stuck in the conveyor system
- plant supervisors manually preparing performance summaries that could be automated
- plant supervisors continuously occupied with maintenance problems.

Keeping the plant operational occupies a large portion of all personnel time at the CHP. In addition, some of the routine paper work now done manually could be automated, which would free up workers for more important duties.

3.12.2 Improvement Opportunities

Improvement in the use of CHP manpower would have an economic impact. More productive use of manpower should reduce the occurrence of operations and maintenance personnel overtime and its attendant costs. By using manpower more efficiently, CHP reliability would be increased.

3.13 OPPORTUNITY INTERACTIONS

The DDSOM addresses several of the 12 problems discussed in Sections 3.1 through 3.12. Although each of the problems were assessed separately, the improvement opportunities do overlap and interact in two principal ways: 1) in solving one problem, another may be partially or completely solved, and 2) solving one problem may effect the potential improvement available from solving others. An example of the first improvement opportunity interaction would be the beneficial impact that a better component maintenance program would have on the ability to control the boilers (see Sections 3.2 and 3.6, respectively). Properly maintained equipment and calibrated instrumentation could lead to fewer boiler trips, which, in turn, would subject the boilers and associated equipment to less stress from thermal cycling. Proper maintenance would also improve the relation between component maintenance and the operation of fuel and ash handling systems (see Sections 3.4, 3.5, and 3.6, respectively). Better overall maintenance would improve the reliability and performance of these handling systems, as well as other handling systems throughout the plant.

The relation between savings from fuel switching and efficiency improvements represents an example of the second type of interaction. Increasing coal use would reduce fuel costs considerably but would decrease the potential savings from increased boiler efficiencies (see Section 3.7).

Interactions among the 12 problems and their improvement opportunities have not been analyzed exhaustively in this assessment. Interactions among problems will be addressed more completely later in the project's Problem Selection Task.

4.0 CONCLUSIONS

Two principal conclusions can be drawn from this value-impact assessment:

- Many improvement opportunities exist at the Quantico CHP.
- A baseline study is required to measure the actual quantitative benefits of implementing the DSSOM at Quantico.

Economic savings are possible by taking actions that increase plant efficiency or extend equipment lifetimes. Higher efficiencies will result in fuel savings, and longer equipment lives will reduce component replacement costs. Better control and maintenance of the plant will also provide the benefits of a more reliable plant with safe working conditions.

A study that establishes the current plant performance is essential if the actual impacts of the DSSOM are ever to be known. Data collected and currently recorded at the plant are insufficient to establish a performance baseline. By measuring the impacts of the DSSOM, the U.S. Marine Corps will have data that will lend greater credibility to estimates of the potential benefits of extending the use of this technology to other sites and applications.

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