Steam Dispatch—Energy Savings for Distributed Steam Heating Systems

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Many commercial and industrial building complexes in the US are served by distributed or district steam heating systems supplied from a central boiler plant at a set steam pressure regardless of demand. Distribution lines are sized to provide adequate steam flow at system peak conditions. Energy savings are available from steam dispatching, reducing the steam distribution pressure under low load conditions. Reducing the system pressure reduces heat losses from distribution surfaces and energy losses from leaks and failed steam traps. This paper describes the preliminary performance analysis of a steam dispatch system that will be implemented at a central plant.

In order to estimate savings from controlled steam pressure dispatching, a spreadsheet model of the distribution system was created. The model calculates building loads, steam line losses, estimated leaks and line pressure drops as a function of ambient air temperature and dispatch pressure. Minimum required operating pressure is determined based on loads, distribution losses, system pressure and end of line pressure requirements. Annual steam load estimates were made using the calculated performance and binned weather data. Substantial energy savings of 10 to 15% were predicted.

INTRODUCTION

In 1994 Hill Air Force Base (the Base) entered into a base-wide energy performance contract with Utah Power and CES/Way International resulting in, among other things, an ongoing search for cost effective energy efficiency projects. This paper describes the current status of one such project; an attempt to reduce fuel consumption and cost by controlling the steam distribution system pressure at one of the Base's steam plants. One energy efficiency opportunity identified during this base-wide search was to save steam by modifying the operation of the steam distribution systems.

The Base has extensive steam distribution systems served by independent central boiler plants. The bulk of the steam plant loads are HVAC related. Most of the plants produce 100+ psig steam though only one plant/distribution system provides high pressure process steam. The remaining steam is used in low pressure space heating applications. Steam is supplied at constant pressure, regardless of demand. Pressures are reduced at the load points, generally where supply lines enter buildings.

A potential opportunity to save significant amounts of energy by dispatching steam -supplying steam only at the pressure needed to meet demand rather than at constant pressure—was identified. This steam dispatching concept is not new but is new for HAFB; testing on a pilot basis is judicious.

The pilot project has two components:

(1) developing a method to predict system performance including an estimate of energy and cost savings potential and,

(2) performance testing including selecting and installing equipment, demonstrating system operation and using operating data to refine the system performance predictions.

We identified several plants as a good candidates for reduced pressure operation during a preliminary survey of energy efficiency opportunities at HAFB. One steam plant was selected for the pilot project. There were several reasons Plant 1590 was selected for pilot testing of the steam dispatch energy conservation measure. First, it is a high pressure plant currently producing and delivering steam at 125 psig. Second, the plant serves a large but relatively simple distribution system. All steam is used for building space heating. The heated buildings are similar, which simplified estimating the building loads. Finally, much of the distribution system is above ground which makes instrument installation, inspections, and measurements easier.

This paper describes only the first component of the pilot project—developing a method for predicting system performance. Plans for the second component—performance testing—are briefly described. The monitoring and control equipment was to be installed for the 1995–1996 heating season but problems with project review, design and equipment selection resulted in delays. The plant came on-line before equipment could be installed. Measure implementation and model verification/tuning are planned for next winter (1996–97 heating season).

BACKGROUND

Many commercial and industrial building complexes in the US are served by distributed or district steam heating systems supplied from a central boiler plant at a set steam pressure regardless of demand. Steam demand for most distribution lines is a function of temperature as it relates to heating demands in consuming buildings. Adequate steam capacity is provided by maintaining distribution pressures. Generally most distribution lines are sized to provide adequate steam at system peak conditions. During most of the heating year the system demand is much less than peak. When the steam demand is down, reduced steam pressure may still supply the required heat. Reducing the system operating pressure saves energy by reducing transmission heat loss from distribution surfaces and reducing the loss from steam leaks. Varying the operating pressure of a steam distribution system in response to load variations is referred to in this paper as steam dispatching.

The steam dispatch concept has been recently demonstrated at Fort Benjamin Harrison Army Base in Indiana (Dilks, Moshage, and Lin, 1993). The demonstration project resulted in a 13% reduction in fuel consumption with a simple payback of less than one year (not including analysis and design costs). The report describes the methodology used to estimate the savings and how the project was implemented. Many of the same techniques can be applied to Hill's steam systems.

Basically, a model of the steam distribution system is created and verified using measurements of existing conditions. Required inputs include building loads, distribution geometry, line thermal losses and leakage. The model is used to determine allowable reductions in dispatch pressure (as a function of temperature) and to calculate the current and potential steam consumption.

Pressure control stations are installed and the steam delivery pressure is modulated in response to varying demand. The pressure control is generally based on measured outside air temperature. Pressure changes are small and slow.

There is software, such as HEATMAP (Washington State Energy Office), available for the design and analysis of flow networks, including steam distribution systems. We did not use commercial software to simulate the pilot steam system because it is too expensive. We felt we could develop a spreadsheet based ''model'' of HAFB's Plant 1590 which could give reasonable energy savings estimates and performance guidelines for much less money than the programs (and learning to use them) would cost.

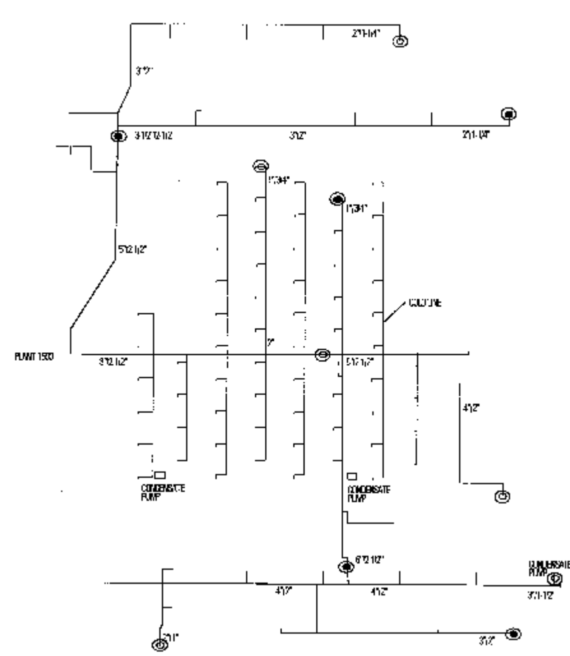
Steam distribution system—Plant 1590 Hill Air Force Base

Hill Air Force Base in Ogden, Utah has multiple steam plants and associated distribution systems which provide heating and process steam to the base facilities. One of these steam plants, Plant 1590, provides space heating steam to multiple storage and inspection buildings including missile and other ordinance storage bunkers. There is a substantial steam distribution system, mostly above ground, associated with the plant. Figure 1 contains a schematic of the distribution system. The plant produces 125 psig steam and the distribution system is maintained at 125 psig during the entire heating season. We identified the plant as a good candidate for reduced pressure operation during a preliminary survey of energy efficiency opportunities at HAFB.

SCOPE

A method used to estimate the savings potential associated with steam pressure regulation -steam dispatch—at Hill Air Force Base's 1590 steam plant is described. In order to calculate potential steam savings available from operating at reduced pressure three related questions had to be addressed.

Figure 1. *Steam Distribution System Schematic.*



(1) What is the relationship between outside air temperature and steam load?

(2) Given an outside air temperature what pressure can the system be operated at?

(3) What is the effect of reduced pressure on the system—capacity, losses and performance?

The development of a spreadsheet-based model designed to address these questions and calculate potential energy savings is described. Our intent was to create a relatively simple (given the inherent complexity of the situation) screening tool to determine if the steam dispatch concept was worth pursuing and to create a system ‘‘model’’ which could be used as a first tool to predict system performance. The intent is to use measured data to refine this system model. Limitations associated with the savings calculations are discussed.

Plans for installation of flow and pressure monitoring equipment and collecting data to verify the savings calculations are described. Measure implementation plans and requirements are discussed. As discussed above the implementation/testing phase of this pilot project has been delayed. Verification/tuning and measure implementation are planned for next winter.

If the results at Plant 1590 are favorable, the steam dispatch system may be installed at other Base steam plants.

METHODOLOGY

A spreadsheet based ‘‘model’’ of the steam system was developed to estimate the steam dispatch savings potential. The boiler plant must produce enough steam to meet the building loads, which necessarily entails meeting distribution system loads and plant operation loads. The overall system load was calculated as the sum of the end (building) loads, the distribution system load (losses both from heat transfer and steam leaks) and plant loads (make up water and feed water heating). System pressure drops are calculated as a function of the load. As the load increases the required flow rate increases, increasing the friction pressure losses. As pressure losses grow the system operating pressure must increase which also increases leakage losses.

Calculations

Load calculations and pressure drop calculations were incorporated into the spreadsheet model. The interaction between load and pressure drop was included. Steam loads and conditions were used to calculate velocity, which was used to calculate pressure drop. The pressure drop was used to calculate line pressure in each section. The line pressure was used to calculate steam properties which, in turn, affect the mass of steam required to meet a given load and pipeline thermal loss (heat transfer) rates. The line pressure also dictates leak rates.

The overall calculation is, therefore, iterative.

(1) Start with the steam supply pressure, thermodynamic properties, and an outside air temperature.

(2) First calculate building loads then calculate distribution thermal losses (loads).

(3) Collect the loads associated with each section of piping and calculate pressure drops in each section.

(4) Use the calculated pressure drop to calculate line pressure in each section.

(5) Use the line pressure to calculate leak rates.

(6) Use the line pressure to recalculate the steam properties in each section.

(7) Use the new properties to recalculate loads, pressure drops, pressure, and properties until the calculation converges.

The calculations are, in general , very simple applications of standard methods for calculating heat transfer, velocity, pressure drop and flow rates.

Because the steam system provides only space-heat steam, steam ‘‘use’’ is due only to building loads which depend on outside air temperatures and leaks which depend on pressure differences and ‘‘hole’’ sizes. Therefore, we started with the assumption that, when operating at a constant supply pressure, the overall system load is a function of outside air temperature and operating pressure.

Steam properties. The model was designed to accommodate changing operating pressures without having to look up values for steam properties for each pressure. We used equations for temperature and enthalpy vs. pressure derived from linear regressions of steam table data. Specific volume vs. pressure was fit to an exponential curve. The resulting equations are used to calculate steam values in the main spread sheet.

Building load. Plant 1590 supplies steam mostly to missile storage bunkers but there are actually four types of buildings connected to the distribution system:

- Igloos—Earth-bermed concrete structures used to store solid fuel missiles and other ordinance, about 3,000 square foot surface area (66 buildings).

- Two story steel and concrete with 14,000 square foot surface area used for ordinance storage, testing and miscellaneous activities (20 buildings).

- One two story brick with about 36,000 square foot surface area.

- One brick warehouse/shipping facility with 42,500 square foot surface area.

The storage facilities have stringent temperature control requirements, they are heated to a constant temperature (75 F) 24 hr/day. We assumed all of the buildings are heated 24 hr/day.

Building loads were calculated from estimated infiltration and envelope losses. Steady state ASHRAE methodology was used. Building transmission loads were estimated as in Equation 1. The overall heat transfer coefficient, U, was estimated for a typical building of each type from building construction information.

$$q_s = U*A*\Delta T \qquad (1)$$

Where:

- q_s = sensible heat load,

- U = overall building heat transfer coefficient,

- A = building surface area, and

- Δt = inside − outside temperature difference.

An infiltration load for each building was also estimated as in Equation 2 (ASHRAE 1993: 23.1). The infiltration flow rate was estimated for each type of building using weather (wind speed) data and building construction information. Latent loads were ignored.

$$q_s = \rho*Q*c_p*\Delta T \qquad (2)$$

Where:

- Q = infiltration air flow rate

- c_p = specific heat of air

- ρ = air density

Distribution system load. Distribution system loads were calculated as a function of the overall heat transfer coefficient, surface area, and the temperature difference (steam to outside air) for each section of pipe in the system. The overall heat transfer coefficient was calculated in the usual manner for insulated pipe; using internal heat transfer coefficient, pipe size and thickness, insulation thickness and thermal conductivity, and external convective heat transfer coefficient.

The steam film coefficient was calculated for each section using the specific volume, the pipe diameter, and the velocity, (Equation 3 below (Babcock & Wilcox 1972: 4–9)). We assumed that the film temperature was the same as the bulk temperature. We did not account for the variation in steam temperature with operating pressure in the film coefficient calculation. The velocity was calculated from the flow in the section (based on the sum of the loads going through the section), the diameter and the specific volume of the steam.

$$U\ steam = (0.023*Fpp*G^{0.8})/(D_i^{\,1.2}) \qquad (3)$$

where:

- G = mass velocity of fluid within pipe

  Fpp = physical properties factor, $c_p^{0.4}\,k^{0.6}/\mu^{0.4}$

- D_i = inside pipe diameter

and,

- (1)Fpp = 0.3

Handbook values for the pipe thermal conductivity, insulation conductivity, and outside air film coefficients were used. The spreadsheet is designed to permit changes in these values.

Heat losses were calculated for each section of pipe in the network using the pipe size and length and insulation thickness.

Heat losses associated with the pipe support systems, exposed valves and steam traps were also estimated.

Leaks. Steam systems leak. Any extensive steam distribution system will have leaks both to the air and to the condensate return system. Fittings, valves and gauges fail, leaking steam to the air. Steam traps fail-open leaking high pressure steam into the condensate return system. Pressure control valves fail-open, or fail to close completely. Steam leaks can result in significant losses in a distributed steam heating system.

In order to estimate the steam ‘‘leak load’’ we assumed the system has two types of leaks: leaks in the distribution piping associated with failed open traps, leaking valves, fittings, gauges, etc. and; leaks at the buildings associated with line and fitting leaks, pressure regulating valve failures, etc.

We assumed the leaks in the distribution system act as small orifices between the outside and inside of the pipe. Steam at line pressure flows though the orifice to atmospheric pressure. After calculating the critical pressure as 35.6 psia, using 12.7 psia for atmospheric pressure, we assumed choked flow through the orifice—that the stagnation pressure in the system was greater than the critical pressure. We do not anticipate operating the distribution system at pressures lower than 50 psig (62.7 psia) at the plant.

The leak rate for each ‘‘hole’’ was calculated (Baumeister, 1972 :4–47) as:

$$m = C*A*P^{0.97} \tag{4}$$

Where:

- m is the mass flow rate,
- A is the orifice area,
- P is the stagnation pressure inside the line and
- C (for saturated steam) is 0.0165

We assumed that each section of pipe had one hole and made sure the hole size could be easily changed in the spreadsheet. This was an aid in the model calibrations discussed below.

Plant load. The steam plant is part of a mostly closed loop system. The four boilers produce steam. The steam flows through the distribution system to the buildings. Condensed steam is returned from the buildings, treated, and deaerated and supplied to the boilers. Some of the steam produced by the boilers never leaves the plant. It is used to heat and deaerate boiler feed water, to drive feed water pumps, and lost through boiler blow-down.

Steam is also lost in the distribution system. The condensate returned is never equal to the steam delivered. Make up water is added as needed.

The plant load was calculated as the steam required to heat the makeup water and condensate return water to the saturated steam temperature at the boiler pressure. We assumed that the feed water (condensate + makeup) was equal to the calculated load, neglecting the steam used by turbine feed-water pumps. The makeup water amount was equal to the sum of the calculated leaks and the boiler blow-down (2% of the delivered steam). The average measured condensate return temperature was 135 F. We assumed a make up water temperature of 60 F.

Pressure drop. The friction loss in each section of line was calculated using the steam velocity and pipe length and inside diameter. The steam velocity was calculated from the mass flow rate and specific volume of steam in the section. The mass flow rate was calculated from the steam enthalpy and loads (building, leaks, and distribution system) supplied by the pipe section.

As discussed above, the pressure drop calculation is iterative. The building (end) loads are calculated for a given outside air temperature. The distribution system loads and leaks are calculated. The loads for each section are collected and a mass flow rate calculated. The velocity is calculated and used to calculate a pressure drop. The resulting pressure is used to recalculate mass flow rate etc. and the calculation is repeated until it converges.

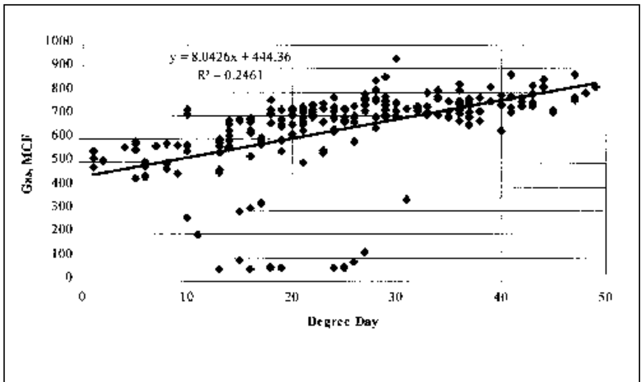
Spread sheet model. Information from the distribution system design, pipe lengths, diameters and locations/connections was used with the calculations described above to develop the spreadsheet model. Calculations were made for each section of pipe. The flow through each section was assumed to be the sum of all of the flows through downstream pipes connected to the section.

Model calibration

The available plant operating data were used to adjust the model. As described above, total plant steam production is not metered. Data recorded on plant operating logs includes daily individual boiler gas consumption, steam production for each boiler with a steam meter (two boilers have operational steam meters, two do not), boiler efficiency for boilers with oxygen sensors, degree days, condensate return temperature, and plant makeup water consumption. There is no pressure monitoring on the distribution system. Building steam consumption is not monitored.

Since we don’t have plant steam production data we could not compare calculated steam with measured steam. The best we could do is compare calculated gas use with measured gas use. The data are daily, not hourly, so the comparison is on a ‘‘daily’’ basis. Data from operating logs for 1994–95 were used. These data are summarized in Figure 2. Measured gas consumption in thousands of cubic feet (MCF) are plotted against heating degree days. A linear regression of the data was performed, the trend line is shown. Equation 5 below is the equation resulting from this linear regression. The data are scattered, and the linear fit is not very good. The y intercept is, however, noteworthy. A significant amount

Figure 2. *Daily Gas Consumption Data (1,00 Ftˆ3) and Heating Degree Days from Plant 1590, 1994–1995 Heating Season.*



of gas is burned on days when the actual heating demand is (or should be) nonexistent. About 440,000 cubic feet of gas is burned on zero-degree-day days. This ''base load'' is about 50% of the maximum daily load recorded and indicates a significant savings opportunity.

$$\text{gas/day } (1{,}000\ \text{ft}\hat{}3) = 8{,}0426\ \text{ft}\hat{}3/\text{degree-day} * \text{degree day} + 444{,}360\ \text{ft}\hat{}3 \qquad (5)$$

Consumption data was compared to calculated data. The spreadsheet was used to calculate a system load (Btu/hr and lb./hr steam) for a given outside air temperature. This load was then used to calculate a gas consumption rate—thousand cubic feet per hour at a given temperature.

The calculations are full of assumptions and ''guesses'' (heat transfer coefficients, leak sizes, etc.) The spreadsheet was designed so that guessed values could be easily adjusted to make the calculation match actual data—data that we presently have and data we hope to gather as the project progresses (see Future Work). The slope of the calculated load vs. degree day line is mostly a function of the heat transfer constants and thermal conductivity used in the calculations. Values in the calculation (insulation thermal conductivity, building overall heat transfer coefficient etc.) were adjusted, changing the slope of the line in order to match the plant gas consumption data.

In modeling the system we also estimated the leak rate by assigning a ''pin hole'' leak to each pipe section. The spreadsheet is designed so that the hole size can be changed, changing the leak rate to match the measured value. Unfortunately we don't have leak rate data to match. We used the plant gas consumption, makeup water data and some performance assumptions to develop a ''target'' leak rate for the model.

Based on the little available plant load data, the plant has a base load of about 440,000 ftˆ3 gas/day. That is, on a zero degree day the plant used an average of 440,000 ftˆ3 of gas. This translates to about 18,300 lb. steam/hr base load. The base load has three components—the plant operating loads, thermal losses from the distribution system which is kept hot and at pressure, and leak losses. Assuming 20% of the base load can be attributed to leak losses in the high pressure system seems reasonable—this translates to a leak loss of 3,600 lb./hr. The leak losses are both leaks to atmosphere, which result in steam loss, and leaks through failed distribution system steam traps. The leaks to atmosphere will show up in the condensate loss, the failed trap leaks will not since the water stays in the system.

In 1994/95 Plant 1590 used about 150,000,000 ftˆ3 of gas and 3,000,000 gallons of makeup water. A mass and heat balance on the steam plant, using gas and makeup water consumption data from the operating logs and assuming a combustion efficiency of 79% gave a make-up water rate of 22%. In 1994/95 the plant operated about 5,000 hours. At 3,600 lb./hr the leaks would have accounted for 2.16 million gallons of water. If all the assumed high pressure leaks were to atmosphere they would account for more than 70% of the makeup water. If half of the assumed high pressure leaks are failed traps then distribution system leaks would account for about a third of the makeup water.

A base leak rate of about 3,600 lb./hr is a reasonable place to start. We adjusted the hole size in the model ending up with a base leak rate of 3,200 lb./hr.

With this hole size we used the model to calculate loads for various temperatures between 0 and 65 F. We adjusted the thermal constants (overall heat transfer coefficient for the buildings etc.) to make the slope of the calculated consumption line match the slope for the actual plant data trend line. Figure 3 shows the data trend line compared to the calculated line. The calculated relationship is given by:

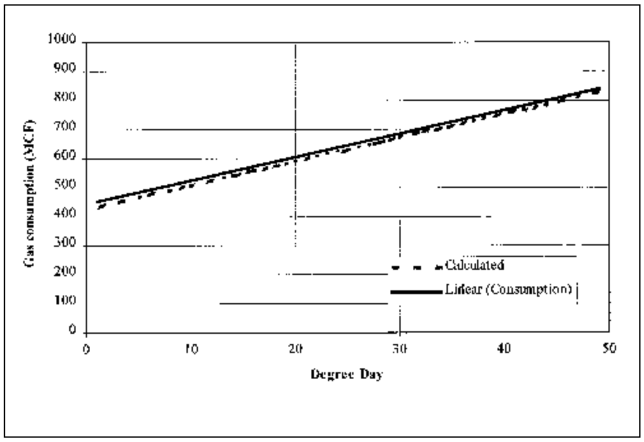
$$\text{gas/day } (1{,}000\ \text{ft}\hat{}3) = 8{,}180\ \text{ft}\hat{}3/\text{degree-day} * \text{degree day} + 428{,}000\ \text{ft}\hat{}3 \qquad (6)$$

The slopes are comparable while the calculated intercept (base load) is higher than the consumption data. (Our first guesses for the thermal constants gave a slope of 7.3 and an intercept of 430.)

Baseline load estimate

The spreadsheet calculates steam plant load (lb./hr) and system pressure drop as a function of outside air temperature and steam supply pressure. It was used with binned weather data to calculate baseline annual steam production and system pressure drops. Critical lines sections of the distribution

Figure 3. Trend-line (Regression) From Gas Data (1,00 Ftˆ3) Compared to Calculated. Consumption vs. Degree day.



system—those with the highest pressure drops—were identified.

Two sets of weather data were used, TMY data for Salt Lake City and actual hourly weather data for Ogden. Hourly temperatures during the heating season (September through April) were binned in 5 degree increments. The calculated annual load, using actual 1992/93 weather data, was 137,000 thousand pounds of steam. At 1.11 ftˆ3 of gas/lb. of steam, this translates to 152 million cubic feet of gas. Operating records indicate that the boilers at Plant 1590 consumed 150 million cubic feet of gas in the 1994/95 heating season (the 1992/93 data are not available, neither were 1994/95 hourly weather data).

The baseline consumption calculation is in reasonable agreement with the available data. As described below, the model will be revised when actual steam production and pressure drop data have been collected.

Steam dispatch—loads at reduced pressure

Reducing the system pressure when actual demand is reduced can result in energy savings. When operating at reduced pressure the energy losses due to heat transfer from the distribution system and leak losses will be reduced. A critical questions is: How much can the pressure be decreased without interfering with the performance of the system?

To answer this the spreadsheet model was used to calculate system pressure drops at various outside air temperatures and operating pressures (see Table 1). Pressure drops were calculated for all lines in the distribution system. Two small steam mains (1 and 1.25 inch lines) consistently had the highest calculated pressure drops. The maximum pressure drop calculated for the system at a supply pressure of 125

Table 1. *Calculated Pressure Drop for Various Outside Air Temperatures and Operating Pressures*

Outside Air Temp F	Pressure Drop @ 125 psig Operating Pressure	‘‘Dispatch’’ Operating Pressure, psig	Pressure Drop @ ‘‘Dispatch’’ Operating Pressure, psia
−10	>125	125	>125
0	108	125	108
10	98	125	98
20	85	105	84
35	69	90	65
45	59	80	52
55	50	62	41
65	42	55	31

psig ranged from over 125 psi at an outside air temperature of −10 F to 42 psi at an outside air temperature of 65 F.

The relationship between maximum pressure drop and outside air temperature was used to determine the minimum required operating pressure for a given outside air temperature. For a given outside air temperature we assigned a minimum operating pressure equal to the maximum pressure drop calculated for 125 psig operation plus 20 at least psi. (Steam traps and PRV valves typically require a minimum pressure difference in the 20 psi range in order to operate properly.)

Using this minimum operating pressure, system loads and pressure drops were calculated for various outside air temperatures. The new maximum pressure drop was compared to the supply pressure (see Table 1 below). The calculations indicate that the supply temperature should remain at 125 psig until the air temperature is 10 F or higher. At outside air temperatures of 65 F the supply pressure can be decreased to 55 psig.

Savings estimate

Reducing the system operating pressure to only that required by the system demand will reduce energy losses in the system by decreasing leak and thermal losses. An estimate of the potential steam savings available from such a steam dispatch process was made. The spreadsheet model was used to calculate the steam load at various outside air temperatures and system operating pressures. Figure 4 summarizes the calculated system loads for various outside air temperatures operating at constant pressure (125 psig) and at reduced, dispatch pressure.

Binned weather data was used to calculate annual energy consumption for the system operating in 'dispatch' mode. The energy savings estimate is the difference between the constant pressure operation consumption and regulated pressure operation.

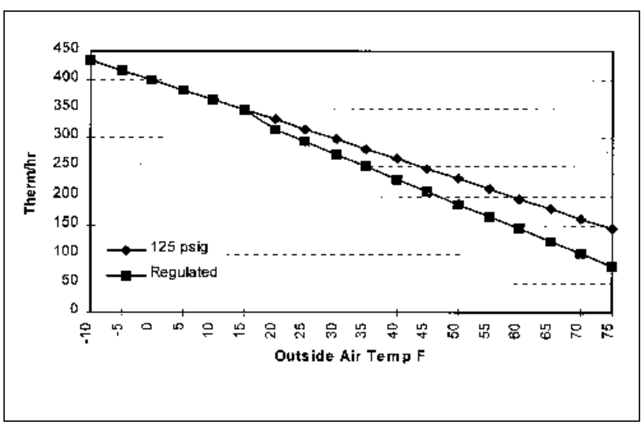
The savings estimate was 210,000 therms annually, about 15% of the 1,379,000 therm baseline calculation.

FUTURE WORK

The spreadsheet model was developed to estimate potential energy savings associated with reducing the system operating pressure. There are two critical requirements for the model, to approximate the system energy loss as a function of outside air temperature and steam pressure, and to estimate the system pressure losses to determine allowable minimum operating pressures (again as a function of temperature and load). Our intent was to get an approximation of how the steam dispatch would work and then use field data, particularly flow, pressure and temperature measurements, to tune the model.

We have a savings estimate and a general idea of how steam dispatching should operate on the Plant 1590 system. The next step is to try it.

Figure 4. *Calculated Load, Constant Pressure Operation Compared to Regulated Pressure, Dispatch Operation At Various Outside Air Temperatures*



Implementation

The measure will be implemented by installing pressure control valves and associated controls and monitoring equipment on the distribution mains. The control valves will reduce the distribution pressure in the lines as the outside air temperature increases and load decreases. Pressure monitoring equipment will be installed on the distribution system in order to assure that sufficient pressure to deliver steam to the buildings is maintained.

Measurements and model tuning

Steam meters will be installed on the two main distribution lines. Pressure monitoring equipment will be installed on the distribution system. Steam flow and pressure will be monitored. Planned instrument locations are indicated on the schematic in Figure 1. The monitoring results will be used to refine model predictions and guide system operation.

CONCLUSIONS

The savings prediction is encouraging.

We estimated a potential reduction of 15% or 220,000 therm reduction in steam load at Plant 1590. At a steam cost of $0.27/therm, this translates to a potential $59,000/yr. savings. Implementation of the measure is expected to be fairly straightforward and inexpensive. The cost to implement the measure, including monitoring equipement for the model verification and tuning was estimated at $120,000.

ACKNOWLEDGMENTS

We are grateful for the help and comments of Jim McMickell, General Foreman, Boiler Operations, Hill Air Force Base and other operations personnel.

ENDNOTES

1. Babcock & Wilcox, 1972. *Steam.* 38 ed. New York, New York: Babcock & Wilcox Company, 4-47, Figure 9, assuming bulk temperature of 300 F.

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