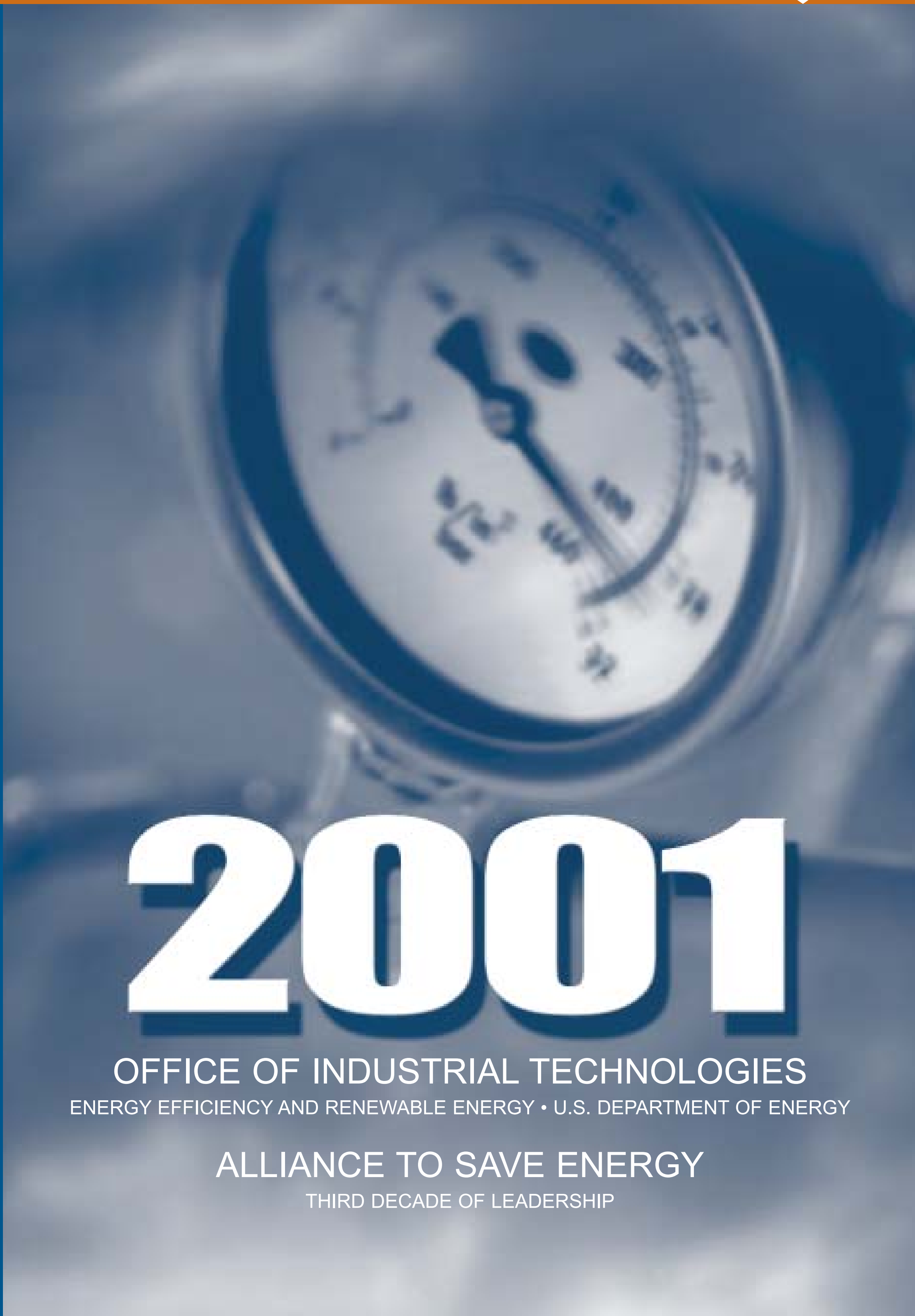
STEAM DIGEST

A compendium of articles on the technical and financial benefits of steam efficiency, presented by stakeholders in the U.S. Department of Energy's BestPractices Steam efforts.



2001

OFFICE OF INDUSTRIAL TECHNOLOGIES
ENERGY EFFICIENCY AND RENEWABLE ENERGY • U.S. DEPARTMENT OF ENERGY

ALLIANCE TO SAVE ENERGY
THIRD DECADE OF LEADERSHIP

Steam Digest

2001

Compiled and produced for

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ENERGY EFFICIENCY and RENEWABLE ENERGY   U.S. DEPARTMENT OF ENERGY

by

THE ALLIANCE TO SAVE ENERGY

THIRD DECADE OF LEADERSHIP

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Acknowledgements

The *Steam Digest 2001* owes its existence to the U.S. Department of Energy's Office of Industrial Technologies (OIT), led by Deputy Assistant Secretary **Denise Swink**. Special Assistant **Marsha Quinn** enables us to interact effectively throughout OIT. Mr. **Fred Hart** of DOE provides dedicated program management for the steam effort, while Mr. **Christopher Russell** of the Alliance to Save Energy leads program marketing and outreach. Dr. **Anthony Wright** of Oak Ridge National Laboratory leads our technical agenda. Ms. **Rachel Madan** of the Alliance provides additional program support. A steering committee consisting of steam experts from industry, business, government, trade associations, and national labs provides guidance to our effort. Mr. **Bill Pitkin** of the National Insulation Association is the Chair of this Steering Committee. His rapport with government and business leaders greatly facilitates all of our accomplishments. Ms. **Debbie Bloom** of ONDEO Nalco is Vice Chair and a peerless referee of our technical content. Mr. **Fred Fendt** of Rohm & Haas is the committee's Executive-at-Large, giving voice to the energy end-user's perspective. Mr. **Glenn Hahn** of Spirax Sarco provides multifaceted leadership within the Steam and the overall BestPractices steering committee structures.

Each of these individuals provided a unique and valuable contribution to the BestPractices Steam Steering Committee throughout 2001:

Bob Bessette
Council of Industrial Boiler Owners
Charles Cottrell
North American Insulation Manufacturers Association
Lee Doran
National Board of Boiler and Pressure Vessel Inspectors
Beverly France
Industrial Interactions
Elodie Geoffroy-Michaels
Turbo Steam
Robert Griffin
Enbridge Consumers Gas
Bill Haman
Iowa Energy Center
Tom Henry
Armstrong Services, Inc.
Ron Holt
Swagelok
Walter Johnson
Association of Energy Engineers
Mike Makofsky
Shannon Enterprises
Anthony Martocci
Bethlehem Steel
Jim McDermott
Yarway Corp.
Kelly Paffel
Plant Evaluations & Support
Miriam Pye
New York State Energy Research & Development Authority
Doug Riley
Millennium Chemicals
Mike Sanders
Sunoco
Thomas Scheetz
BASF
John Todd
Yarway Corp.

All of our steering committee members volunteer their time to BestPractices Steam, and our appreciation is underscored here. A previously unheralded contributor to the program is Mr. **Carlo LaPorta** of Future Tech, who is the "utility in-fielder" on our management team.

We thank each author for his or her contribution to this compendium. Mr. **David Jaber** provided several articles; he has since left the employ of the Alliance to Save Energy and we wish him well in his new endeavors.

As was the case last year, a note of thanks goes to Ms. **Sharon Sniffen** of ORC Macro International, whose staff gave *Steam Digest 2001* this final form.

Introduction

Fred Hart, U.S. Department of Energy
Christopher Russell, Alliance to Save Energy
Anthony Wright, Oak Ridge National Laboratory
September 2001

BestPractices Steam, which began in 1997 as the *Steam Challenge*, is one component of the U.S. Department of Energy's Energy Management *BestPractices* industrial technology assistance effort. BestPractices spearheads the implementation approach for the Industries of the Future (IOF) program. The activities of BestPractices are broad based, covering all aspects of the IOF program and include energy assessments, sponsorship of emerging technologies, and energy management. BestPractices activities assist the nine IOF industries to identify and realize their best energy efficiency and pollution prevention options from a systems and life-cycle cost perspective. In the interest of documenting and communicating best-in-class applications of industrial energy technologies, this volume is made freely available to the industrial community. It is hoped that it will influence plant management for the betterment of U.S. industrial energy consumption, productivity, competitiveness, and shareholder value.

Steam Digest 2001 chronicles our contributions to the industrial trade press over the past year. As in last year's *Steam Digest*, we present articles that cover technical, financial, and managerial aspects of steam optimization. A number of these articles detail plant- or company-specific success stories. Other articles describe technical opportunities and how to measure their impact on plant performance.

Through 2001, BestPractices Steam continued to make progress in developing tools to assist steam users in achieving system improvements. In one sense, our progress can be measured in the number and quality of resources produced. Instruments such as the spreadsheet-based *Steam Scoping Tool* and the *3E Plus* insulation evaluation software have become popular with plant managers as diagnostic tools. A series of Steam Tip Sheets—now numbering 16—are useful one-page references that identify distinct energy saving opportunities and demonstrate the calculation of related financial impacts. Case studies are an in-depth demonstration of site-specific experiences with steam optimization programs. The ongoing conduct of workshops and trade show participation makes the BestPractices name visible on a regional basis.

Additionally, the Steam Clearinghouse provides basic reference, assistance, and referral to callers who use the toll-free number. Steam users, consultants, vendors, and utilities all use the Clearinghouse at no cost to obtain the resources described here. The *Steaming Ahead* newsletter and companion website (www.steamingahead.org) provide the steam community with regular updates on program progress. The public may also download software and references from that website. There are more tools to come in the future: results of the Steam Market Assessment, development of detailed Steam Technical Fact Sheets, and enhancements to our Steam Workshops.

While the product and service offerings of BestPractices Steam are many and varied, the current challenge is to get this information in the right hands. Energy efficiency is not an end in itself, but a means toward the very goals sought daily by plant managers and their corporate leaders. Both technical and business leaders need access to BestPractices Steam in order for our information to be thoroughly effective. This is our leading mandate for 2002, and beyond.

For more information, please contact:

U.S. DOE Office of Industrial Technologies
Resource Room
Phone: (202) 586-2090

The OIT Clearinghouse
Email: clearinghouse@ee.doe.gov
Phone: (800) 862-2086

Or visit our websites:

The U.S. Department of Energy's Office of Industrial Technologies:
http://www.oit.doe.gov/bestpractices/steam

The *Steaming Ahead* resource page:
http://www.steamingahead.org

BestPractices Steam Resources and Tools: "Old" News is "New" News!

Anthony Wright, Oak Ridge National Laboratory
Fred Hart, U.S. Department of Energy
Christopher Russell, Alliance to Save Energy
David Jaber, (formerly with) Alliance to Save Energy

Abstract

The U.S. Department of Energy Office of Industrial Technology (DOE-OIT) BestPractices efforts aim to assist U.S. industry in adopting near-term energy-efficient technologies and practices through voluntary, technical assistance programs on improved system efficiency. The BestPractices Steam effort, a part of the DOE-OIT effort, has identified and documented an extensive group of steam system resources and tools to assist steam system users to improve their systems. This paper describes the "new" news that BestPractices Steam is assembling from the "old" news about opportunities and techniques to improve steam systems.

Introduction

In his 1947 classic text, "The Efficient Use of Steam," Sir Oliver Lyle noted that:

> *"There are three fundamental things, and three only, that should guide our steam economy, and we should strive after them with might and main:*
>
> *(1) Prevent the escape of heat.*
> *(2) Reduce the work to be done.*
> *(3) Use the heat over again."* [1]

More than 50 years later, Sir Lyle's "old" news is being translated into "new" news in a national effort to improve the U.S. industrial economy through improvements to industrial process steam systems.

The U.S. Department of Energy (DOE) Office of Industrial Technology (OIT) BestPractices efforts aim to assist U.S. industry in adopting near-term energy-efficient technologies and practices through voluntary, technical assistance programs on improved system efficiency. There are nine industry groups - designated Industries of the Future (IOFs) - that are the focus of the OIT efforts. These IOFs include Agriculture, Aluminum, Chemicals, Forest Products, Glass, Metal Casting, Mining, Petroleum, and Steel. BestPractices efforts cover motors, compressed air, steam, and combined heat and power systems.

The overall goal of the BestPractices efforts is to assist steam users in adopting a systems approach to designing, installing and operating boilers, distribution systems, and steam applications. BestPractices Steam is led by the DOE-OIT and the Alliance to Save Energy, and is supported by a Steering Committee of steam system users, steam system service providers, and relevant trade associations.

One of the major 1999 goals of the BestPractices Steam effort was to identify and document an extensive group of steam system resources and tools. There were three main objectives in identifying and documenting these tools and resources:

1. To create an information base to "make the case" for the opportunities available to significantly enhance industrial steam systems.
2. To identify resources to assist steam system users to improve their steam systems.
3. To identify what new resources and tools can be created to assist steam system users in the future.

This article describes the outstanding "new" news that is being created from "old" news by BestPractices Steam.

Technical Tools and Information

Technical References and Technical Tools

Two types of steam system technical information have been collected:

1. A listing of available steam system technical ref-erences and standards.
2. A listing of available steam system technical tools.

The members of the BestPractices Steam Steering Committee and Subcommittees provided information on key references and tools that they used in their work or that they knew about. This information was assembled and put onto the BestPractices Steam website for future use by steam system users and service providers. A summary of the information collected is noted below:

1. A list of 82 steam technical references and standard documents has been compiled. These documents have been categorized on the web- site under the categories of generation, distribution, end use, recovery, and total steam system. The listing provides the document name, author, and a brief description of the document.
2. A list of 66 steam technical tools has also been compiled. The technical tools have been categorized on the website under the categories of diagnostic equipment (11), guidelines (19), and software products (36).

Steam Tips

A Steam Energy **Tip** is a brief (typically one page) writeup of a best practice - including a description, an example application, and suggested actions for applying the improvement opportunity.

The Georgia Tech Industrial Energy Extension Service developed a series of Steam Tip fact sheets. During the past year, BestPractices Steam has adapted the Georgia Tech Steam Tip sheets and has now published 16 of these:

- Improve Boiler Combustion Efficiency
- Inspect Steam Traps
- Recover Heat from Boiler Blowdown
- Minimize Boiler Blowdown
- Removable Insulation on Valves & Fittings
- Waste Steam for Absorption Chillers
- Flash Condensate to Low-Pressure Steam
- Minimize Boiler Short-Cycling Losses
- Insulate Distribution an d Condensate Lines
- Economizers for Waste Heat Recovery
- Clear Boiler Water-side Heat Transfer Services
- Return Condensate to the Boiler
- Deareators in Industrial Steam Systems
- Vapor Recompression to Recover Waste Steam
- Use Vent Condenser to Recover Flash Steam
- Benchmark the Fuel Cost of Steam Generation

These Steam Tips can be printed and/or downloaded from the BestPractices Steam website.

NAIMA 3E-Plus Insulation Software

The North American Insulation Manufacturers Association (NAIMA) 3E-Plus software program quantifies the economic thickness of an insulation application through heat flow calculations, and estimates greenhouse gas reductions resulting from insulation improvements. An IBM-PC DOS version of this program is available from our website; and a new Windows version is anticipated in the near future.

Energy Efficiency Handbook

The Council of Industrial Boiler Operators (CIBO) developed an Energy Efficiency Handbook. This handbook was prepared to help steam system owners and operators get the best energy-efficient performance out of their steam systems. The handbook provides information and helpful operational tips on many aspects of steam system operation, including water treatment, boiler operations and controls, heat recovery, and cogeneration. The Energy Efficiency Handbook can be obtained from the BestPractices Steam website.

Best Practices and Case Studies

A **best practice** is a preferred and/or excellent way of performing an activity.

A **case study** is a detailed description of an industrial project that produced energy savings, economic benefit, etc.

Documenting new and presently available best practices and case studies is one of the best ways to create awareness about opportunities for improving industrial steam systems.

Documenting New Case Studies

During the past year, BestPractices Steam has collaborated with the following organizations to document their recent steam system improvement efforts in the form of case study writeups:

- Chemical Manufacturer's Association (CMA) 1997 Energy Efficiency Award Winners
- Mobil Energy Management
- Bethlehem Steel

- Georgia Pacific
- Babcock and Wilcox
- Texas Instruments

These case studies are developed by: a) obtaining initial information about the improvement effort from individual companies; b) reviewing the information to verify that the stated energy savings are realistic; c) preparing draft case studies for review; and d) revising and finalizing the case study writeups.

Table 1 summarizes some of the annual savings that have been achieved in the industrial case studies that we have documented to date. The information in the table illustrates that significant steam system energy improvements and cost savings are possible, with short paybacks, from improvements that many steam users could make to their steam systems.

Detailed case study writeups for the efforts summarized in **Table 1** are available on our website, or from the Steam Clearinghouse.

Available Best Practices, Case Study Information

There are numerous reports and articles published in trade publications, technical journals, and conference proceedings documenting available steam system best practices and case studies. We have initiated an effort to document available best practices and case study publications; we obtained this information primarily from members of our Steering Committee.

At the present time, we have documented 40 available best practices publications and 18 available case study publications on our website. We have identified the information source for each document (for example, a reprint from a trade magazine), the application in the steam system for the document, and the purpose of the best practices or case study. Additional best practices and case studies can be submitted on-line through the website.

Table 1. Summary of Selected Steam Case Study Improvement Results

Company[a]	Brief Description of Steam Improvement Made	Annual Savings ($)	Simple Payback (years)
Nalco	Reduce steam header pressure.	$142,000	minimal
Vulcan Chemicals	Reduce steam pressure in distillation columns.	$42,000	minimal
Mobil, Mary Ann Gas	Improve steam system control scheme.	$400,000	minimal
Mobil, Nigeria	Install additional steam traps on drum oven.	≥$50,000	0.1
Velsicol Chemical	Improve steam trap maintenance program.	$100,000	≤ 0.2
Texas Petrochemical	Replace faulty compressor turbine, and reconfigure steam and cooling systems.	$2,300,000	≤ 0.25
Georgia Pacific	Insulate steam lines, replace faulty steam traps.	$138,560	0.5
Texas Instruments	Replace existing steam boiler sytem, improve plant heat recovery.	$1,303,500	1
Bethlehem Steel	Rebuild and upgrade steam turbine.	$3,300,000	1
Babcock and Wilcox	Install new boiler combustion controls, replace more than 90% of system steam traps.	$250,000	≤ 1.5

[a]Nalco, Vulcan, Velsicol, and Texas Petrochemical are CMA Energy Efficiency Award winners.

TRAINING

The BestPractices Steam Training Subcommittee initiated an effort to identify steam training courses available in the U.S. Prior to this effort, the extent of available steam training in the U.S. was not known. This was not an effort to endorse particular training programs over others.

The Training Subcommittee has now identified an extensive list of available steam training courses, and this list is documented on our website. At the present time, we are aware of 80 steam training courses that are being provided by 31 different organizations.

One outcome of identifying available steam training is that there appears to be a need for operator training and/or training guidelines for operating and maintaining boiler systems. Based on this identified need, the National Board of Pressure Vessel Inspectors is in the process of developing an operator course.

AWARENESS RESOURCES

The Awareness Resources listed below (available at no cost) have been developed to assist steam system users and service providers to obtain the "new" news from the BestPractices Steam efforts.

Web site

All of the technical resource and tool information assembled by BestPractices related to steam systems is available on our website at:
www.oit.doe.gov/bestpractices/steam and
www.steamingahead.org

In addition, information on resources and tools that are available for the overall DOE-OIT effort is available from the following web address:
http://www.oit.doe.gov/techdeliv.shtml

Clearinghouse

Through Washington State University, a Clearinghouse has been set up that can be contacted to obtain OIT BestPractices publications and technical assistance on steam system related questions. The contact information for the Clearinghouse is: Phone: (800) 862-2086
Email: clearinghouse@ee.doe.gov

Steaming Ahead Newsletter

Each month, BestPractices Steam publishes this on-line newsletter (available on the website) to provide information on activities being performed, future steam system workshops and conferences, and other information of interest to the steam system user and service provider community. See www.steamingahead.org

Energy Matters Newsletter

Energy Matters is a bimonthly OIT publication that focuses on energy savings opportunities for motor, steam, compressed air, and combined heat and power systems. It is available by subscription for free; information on subscribing to *Energy Matters* is available from the DOE-OIT web site or through the Clearinghouse.

Steam Awareness Workshops

BestPractices Steam has conducted steam awareness workshops designed to make steam users aware of the opportunities available to improve their steam systems. Most of the workshops have been co-sponsored by the Alliance to Save Energy and a steam service provider. Typical formats for these workshops have included:

1. Presentations on the BestPractices Steam efforts and opportunities to improve industrial steam systems.
2. Presentations on other energy and productivity improvements available through government and private sources.
3. Steam user presentations on specific improvements they have made to their process systems.

More than a dozen of these workshops have successfully been conducted, and we plan to conduct at least this many additional workshops this year.

FUTURE RESOURCES AND TOOLS

BestPractices Steam is developing additional resources and tools to assist steam users. Major resources and tools under development are described below.

Steam System Opportunity Assessment

A major industrial steam system market assessment has recently been initiated by DOE-OIT. The

Steam System Opportunities Assessment will have four major objectives:

1. To develop baseline information on U.S. process industry steam generation, use, and opportunities for steam system improvements.
2. To identify steam system design, maintenance, and management practices presently used by U.S. process industry.
3. To develop a methodology to assess the effectiveness of efforts to influence U.S. industry to improve their steam system operations.
4. To educate and influence industry and government decision makers on the benefits that can be realized from steam system efficiency improvements.

This effort will establish parameters describing the industrial market for steam efficiency improvements. It is anticipated that the Opportunity Assessment will take one to two years to complete.

Steam Systems Sourcebook

BestPractices Steam has developed a Steam Systems Sourcebook to increase awareness of energy saving opportunities in industrial steam systems. The Sourcebook is intended to increase awareness of energy efficiency opportunities among plant engineers, facility managers, and system operators.

The Sourcebook contains three main sections:

1. A "Steam Basics" section that describes the fundamentals of steam system operation.
2. A "Fact Sheet" section that provides greater details regarding specific steam system performance improvement opportunities.
3. A "Where to Find Help" section that describes where steam system users can obtain further information to assist their system improvement efforts.

Steam System Survey Guidelines

BestPractices Steam has developed a set of Steam System Survey Guidelines for use by steam system users. The specific audience for these guidelines is users who are not sure how to initiate a steam system improvement program. The Survey Guidelines cover the following topical areas:

1. Steam System Profiling (how much steam do you use, how much are your fuel costs, how does improved boiler efficiency translate to saved costs, etc.).
2. Steam Generation.
3. Steam Distribution and Losses.
4. Steam Utilization.

Each section of the guidelines includes discussion of improvement opportunities and examples that users can follow to quantify the possible improvements in their individual systems.

Conclusion

In developing a comprehensive set of steam system resources and tools, BestPractices could not have said it any better than Sir Oliver Lyle did:

> *"All thermal devices deserve investigation, deserve a careful estimate of their probable cost, and deserve a conscientious calculation of the return they may bring."* [1]

BestPractices Steam is committed to developing tools and resources to help steam system users create "new" news of energy and productivity improvements in their process steam systems.

For more information contact:

Dr. Anthony Wright
Oak Ridge National Laboratory
Email: alw@ornl.gov
Phone: (865) 574-6878

Fred Hart
U.S. Department of Energy
Email: fred.hart@hq.doe.gov
Phone: (202) 586-1496

Christopher Russell
Alliance to Save Energy
Email: crussell@ase.org
Phone: (202) 530-2225

References

1. Oliver Lyle, **1947** ***The Efficient Use of Steam***, *Her Majesty's Stationery Office*.

Best Practices in Steam System Management

Fred L. Hart, U.S. Dept of Energy
David Jaber, (formerly with) Alliance to Save Energy

Achieving operational excellence is a continuous task for all manufacturers working to reduce costs and keep their plants profitable. Luckily, many opportunities exist for industrial plants to cut costs without jeopardizing jobs or the environment. For example, over 50 percent of the input fuel used by the U.S. manufacturing sector is used to generate steam. More importantly, in a typical facility, a 20 to 30 percent improvement in steam system efficiency, i.e., the ability to meet their steam needs with 20 to 30 percent less fuel, is possible. At an estimated annual cost of $18 billion for fuel, alone, in the 33,000 boilers used by industry, reducing steam fuel use can improve profits nationally.[1] The chemicals industry can particularly benefit as it is very steam intensive; steam production accounts for over 50 percent of fuel used by the sector. Other sectors which really benefit through steam system improvements include pulp and paper, food processors, steel mills, petroleum refining, and textiles.

Common areas in which to look for savings opportunities in steam generation, distribution, end use and recovery are outlined below.[2] By determining which are the most appropriate at a given plant, a good start can be made on improving the productivity and reliability of the plant, while cutting unnecessary costs.

Steam Generation

Demand Reduction

The boilers may well be producing more steam than is needed for the end uses. Evaluation of demand is especially important when downstream improvements such as insulation and condensate return are implemented - lower loss means lower generation needs. At Nalco Chemical Company's Clearing Plant in Bedford Park, Illinois, a process engineer determined that a steam header pressure of 125 psig was no longer necessary due to changes in the some of the plant's processes. A team of personnel from the maintenance, utilities, and production departments evaluated the feasibility of reducing the header pressure and decided to incrementally decrease header pressure while monitoring the effects of this change on system performance.

The pressure was reduced twice, first to 115 psig, and then to 100 psig. After determining no detrimental impacts on system operation, Nalco now operates the system at 100 psig, resulting in annual energy savings of 8 percent, far exceeding initial expectations, and saving $142,000 annually along with reduced carbon emissions. For this work, the plant received a 1997 Chemical Manufacturers Association Energy Efficiency Award.[3]

In addition to a straight boiler generation reduction, a specific end use pressure might be reduced. As part of their Operational Excellence Program, Vulcan Chemicals, a business group of the Vulcan Materials Company, implemented a process optimization project involving two chloromethane production units. This four-month project required no capital investment and resulted in a reduction in process steam demand and significant cost savings. Vulcan lowered the steam system pressure in the first distillation column from 35 to 26 psig. This gave them a lower condensing temperature that requires less reflux during component separation. Average reboiler steam demand per unit of product decreased by almost 6 percent and resulted in yearly cost savings of $42,000. This plant also received a Chemical Manufacturers Association Energy Efficiency Award in 1997 for the project.[4]

Boiler Tune-Up

The major areas of opportunity in boiler tune-up encompass excess air and blowdown optimization. Optimum excess air minimizes stack heat loss from extra air flow while ensuring complete fuel combustion. Stack temperature and flue gas oxygen (or carbon dioxide) content are the primary indicators of the appropriate excess air level; an adequately-designed system should be able to attain a 10 percent excess air level. The required action is to monitor flue gas composition regularly with gas absorbing test kits or computer-based analyzers. Highly variable steam flows or fuel composition may require an on-line oxygen analyzer, also called oxygen trim control.

Optimizing boiler blowdown helps keep steam quality high for effective production, while reducing fuel and water treatment expenses. Blowdown rates typically range from 4 to 8 percent. Relatively pure feedwater may require less, where high solids content water requires more. Extensive operating practices have been developed by an AIChE sister organization, the American Society for Mechanical Engineers. These blowdown practices depend on operating pressures, steam purity needs, and water deposit sensitivity of the system. For best blowdown results, investigate the ASME guidelines and also look into continuous blowdown control systems to help maintain optimal blowdown levels.

Clean Heat Transfer

Scale build-up can cause safety hazards from heat exchanger tube failure and boiler metal overheating, in addition to excess fuel use of up to 5 percent. Heat transfer surfaces can be kept relatively clean by pretreating boiler makeup water with water softeners, reverse osmosis, and/or demineralizers, treating returned condensate, if needed, and adopting proper blowdown practices. Remove existing scale either mechanically or through acid cleaning. It can also be useful to consult a specialist in water treatment.

Auxiliary Equipment

In addition to the automatic blowdown control system and oxygen trim control already mentioned, other equipment which can increase boiler efficiency include economizers, blowdown heat recovery systems, and controls. Economizers transfer heat from the flue gas to the feedwater, and are appropriate when insufficient heat transfer (assuming heat transfer is clean of scale) exists within the boiler to remove combustion heat. Good boiler candidates are those above 100 boiler horsepower. Determine the stack temperature and minimum stack temperature to avoid corrosion (250° C if natural gas is the fuel; 300° C for coal and low sulfur oils; and 350° C for high sulfur oils) after tuning boiler to manufacturer specifications. This will help indicate whether or not an economizer makes sense economically in the plant.

Blowdown heat recovery systems preheat boiler make-up water using the blowdown water removed and make sense in continuous boiler blowdown systems. Blowdown waste heat can be recovered simply with a heat exchanger, or in a flash tank. For controls, an oxygen trim control system provides feedback to the burner controls to automatically minimize excess combustion air for an optimum air to fuel ratio. This can result in fuel savings of 3 to 5 percent and is useful where fuel composition is highly variable.

Steam Distribution

Steam Leaks

Steam leaks can be dangerous in higher-pressure systems, above and beyond the significant energy waste they represent. Steam leaks are often found at valve stems, unions, pressure regulators, equipment connection flanges, and pipe joints. The first step is to conduct a steam leak survey. Large steam leaks are visible and ultrasonic detectors can identify even very small leaks. Tag the leaks and determine which can be repaired by your maintenance staff and which require service technicians.

Steam Traps

In steam systems that have not been maintained for 3 to 5 years, from 15 to 30 percent of traps may have failed, and regularly-scheduled maintenance should reduce this to under 5 percent of traps. The cost of one medium-sized steam trap that failed to open in an average pressure system might be $3,000 per year and more. Traps can be tested by a range of means, including visual inspection, listening to the sound, pyrometers, and ultrasonic and infrared detectors.

For optimum performance, establish a regular trap inspection, testing, and repair program that includes a reporting mechanism to ensure replicability and provides for documenting energy and dollar savings. Velsicol Chemical's Chestertown, Maryland, facility implemented a preventive maintenance (PM) program to identify energy losses in their steam system. Velsicol's PM program inventoried the plant's steam traps, trained system operators to identify failed traps, and improved communication between maintenance and production personnel so that failed traps were quickly repaired or replaced. This program also identified improperly sized traps or traps of the wrong type and planned their replacement.

Implementing the program saves Velsicol over $80,000 annually at an initial cost of just $22,000. It also reduced energy consumption on a per production unit basis by 28 percent, and had a payback of just over 2.5 months. The plant received a 1997 Chemical Manufacturers Association Energy Efficiency Award for the project. The effort reduced annual CO_2 emissions by 2,400 tons. Yet another benefit was the reduced worker exposure to treatment chemicals.[5] A large Rohm and Haas methyl methacrylate plant in Kentucky, implementing a similar program, saved nearly $500,000 each year.

Insulation

Insulation helps ensure proper steam pressure for production and can reduce radiative heat loss from surfaces by 90 percent.[6] The Department of Energy (DOE) Industrial Assessment Center program demonstrated a savings potential ranging from 3 percent to as high as 13 percent of total natural gas usage on average through insulation installation. The optimum insulation thickness can be calculated with the DOE 3E+ software program. Depending on pipe size and temperature, needed insulation thickness may range from one inch to over eight inches. For steam systems specifically, common insulating materials include fiberglass, mineral fiber, calcium silicate, and cellular glass. Material choice depends on moisture, temperature, physical stress, and other environmental variables.

Appropriate actions include: first, insulate steam and condensate return piping, boiler surfaces, and fittings over 120 degrees Fahrenheit; second, conduct a survey of the overall facility steam system every five years for deteriorated and wet insulation; and third, repair or replace damaged insulation. As an example, Georgia Pacific's plywood plant in Madison, Georgia, insulated several steam lines leading to its pulp dryers. Using 3E+, they determined an optimal insulation for their steam lines and installed mineral fiber insulation. Georgia Pacific found this made their work environment safer and improved process efficiency. Together with steam trap maintenance, the plant reduced its fuel costs by roughly one-third over the year and also lowered emissions — 9.5 million lbs. of carbon dioxide (carbon equivalent), 3,500 lbs. of SOx, and 26,000 lbs of NOx on an annual basis.[7]

Steam Recovery

Condensate Return

Return of high purity condensate reduces boiler blowdown energy losses and makeup water. This saves 15 to 18 percent of the fuel used to heat the cool makeup water, saves the water itself, and saves treatment costs and chemicals. Reduced condensate discharge into the sewer system also reduces disposal costs. Repair condensate return piping leaks for best results. If the condensate return system is absent, estimate the cost of a condensate return system and install one if economically justified.

Flash Steam Recovery

When the pressure of saturated condensate is reduced, a portion of the liquid "flashes" to steam at a lower pressure. This can be intentionally done to generate steam or unintentionally. Flash steam contains anywhere from 10 to 40 percent of the energy content of the original condensate depending on the pressures involved.

Often the steam is vented and lost; however, a heat exchanger can be placed in the vent. Inspect vent pipes of receiver tanks and deaerators for excessive flash steam plumes and install heat exchangers.

As an example illustrating the economics of steam and condensate recovery, the Bethlehem Steel Burns Harbor plant returned a portion of its warm condenser cooling water exhaust stream to the boiler feedwater and rerouted low pressure waste steam into a steam turbine generator. This along with a turbine rebuild results in annual savings of approximately 40,000 MWh of electricity, 85,000 MMBtu of natural gas, and nearly $3.3 million. With a cost of $3.4 million more than a standard maintenance overhaul, the project had a simple payback of just over one year.[8] The project also reduced high-temperature water discharge into the harbor and decreased coke-oven and blast-furnace gas emissions by 27,200,000 lbs. of carbon equivalent, 294,000 lbs. of SOx, 370,000 lbs of NOx, 11,600 lbs. of PM_{10}, 1,450 lbs of VOCs, and 14,000 lbs of CO.

Putting It All Together

The above tips point out the power of taking a systems approach to energy management. Returning condensate and recovering heat from the end of the process makes true steam demand assessment, clean heat transfer maintenance, environmental emissions control, and fuel use minimization at the boiler easier. Pursuing the systems approach can be facilitated by using the resources of the DOE Office of Industrial Technologies, which is the source of most of the above guidance. DOE assistance focuses on helping industry in developing and adopting energy-efficient technologies and practices through voluntary technical assistance programs on plant-wide energy efficiency. Areas of focus include industry-specific emerging technologies, industrial steam systems, electric motors, drives and pumps, industrial compressed air systems, and combined heat and power systems.

In conjunction with the Alliance to Save Energy and industry steam experts, a network of resources has been established to help steam-using industrial plants adopt a systems approach to designing, installing and operating boilers, distribution systems, and steam applications. Benefits of the systems approach include lower operating costs, lower emissions, increased plant operation reliability, and increased productivity. Specific resources include:

- Tip sheets.
- Case studies.
- Answers to technical questions.
- Databases of training opportunities, technical tools, references and standards.
- Workshops which bring together public manu-facturing resources, private-sector energy management assistance, and peer networking opportunities.
- Plant-wide assessment opportunities.
- Technical papers.
- Project financing guidance tools.
- Publicity and awards through case study data.

Existing resources are available through the Industries of the Future Clearinghouse ((800) 862-2086, clearinghouse@ee.doe.gov), the website (www.oit.doe.gov/bestpractices/steam) and the OIT resource room at (202) 586-2090. These resources also include a Sourcebook providing a comprehensive steam system overview and references and a Steam Scoping software tool providing guidance on how to profile and assess steam systems.

Case studies in particular have a lot of power, and many of these are specific to the chemical industry. Internally, case studies help foster success replication for other company facilities as well as achieve internal company recognition. Externally, the company can receive recognition as an industry leader. DOE is available for assistance in case study documentation.

Conclusion

Too many manufacturing facilities are not achieving their full potential because of poorly operated and maintained steam systems. Steam efficiency lies at that rarely visited intersection of improved economic performance, greater energy-efficiency, and environmental benefit. By taking advantage of available public and private energy management resources, any manufacturer can benefit.

Continuous improvement and maintenance of steam system efficiency through monitoring and maintenance leads to greater reliability, cost effective production and price competitive products. The following steps help pursue the systems approach: 1) Walk through your entire steam system by performing an audit, 2) Document the audit results and make appropriate improvements as outlined here; and 3) Develop and implement a program for ongoing maintenance. The long term benefits of system efficiency require continuous improvement through proper operating and maintenance practices. This prevents a system from degrading into a mode of poor performance.

Heightened awareness of operating costs and performance implications is key to understanding the importance of steam system management. Additional ways to discover and capture savings opportunities are by sharing experiences within and outside the company, and increasing interaction between facility operations and management to reconcile production and engineering facts with the financial and corporate priorities.

For more information contact:

Fred Hart
U.S. Department of Energy
Email: fred.hart@hq.doe.gov
Phone: (202) 586-1496

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Best Practices: The Engineering Approach for Industrial Boilers

Natalie R. Blake, ONDEO Nalco

Abstract

A plant's boilers represent a large capital investment, as well as a crucial portion of overall plant operations. It is important to have systems and procedures in place to protect this investment, as well as plant profitability. Boiler best practices represent "The Engineering Approach for Boilers"—a way to examine mechanical, operational and chemical aspects of the systems (pretreatment through condensate) to ensure reliable boiler operations with no surprises.

Introduction

All industrial plants have boilers of one type or another, often more than one type. Whether the plant in question has one small boiler, or many large ones, the boilers are an essential element of every plant, regardless of plant size or of product produced. With skyrocketing fuel and energy costs, maintaining both boiler reliability and consistent system performance while minimizing energy costs can be a challenge and an opportunity for any utility operation. The Engineering Approach provides a framework to examine all aspects of boiler best practices to optimize system performance, and total cost of operations.

Implementing the Engineering Approach assists in gathering information to measure and track progress, to initiate further improvements, and to allow benchmarking and norming of systems across corporations and within industries.

There are several steps in the effective implementation of the Engineering Approach, or best practices for boilers. This article will discuss the philosophy of the Engineering Approach, as well as examples of its implementation, and the benefits received from it both in terms of system operation, and in terms of total cost of operations.

What Is the Engineering Approach?

The Engineering Approach represents the formalization of ONDEO Nalco's approach to serving our customers. It is fundamentally a customer-centric method of doing business that permits the management of knowledge of the customer's water system, and knowledge of the impact that water systems can have on process operations, environmental performance, and overall costs. This engineering knowledge is used to significantly build value for the customer.

The fundamental elements of the Engineering Approach are mechanical (M), operational (O) and chemical (C) considerations. This provides a system that:

- Is independent of personnel movement to new assignments (customer or consultant).
- Focuses on results.
- Is proactive in the prevention of problems.
- Identifies opportunities to reduce total cost of operation (TCO) for the plant.

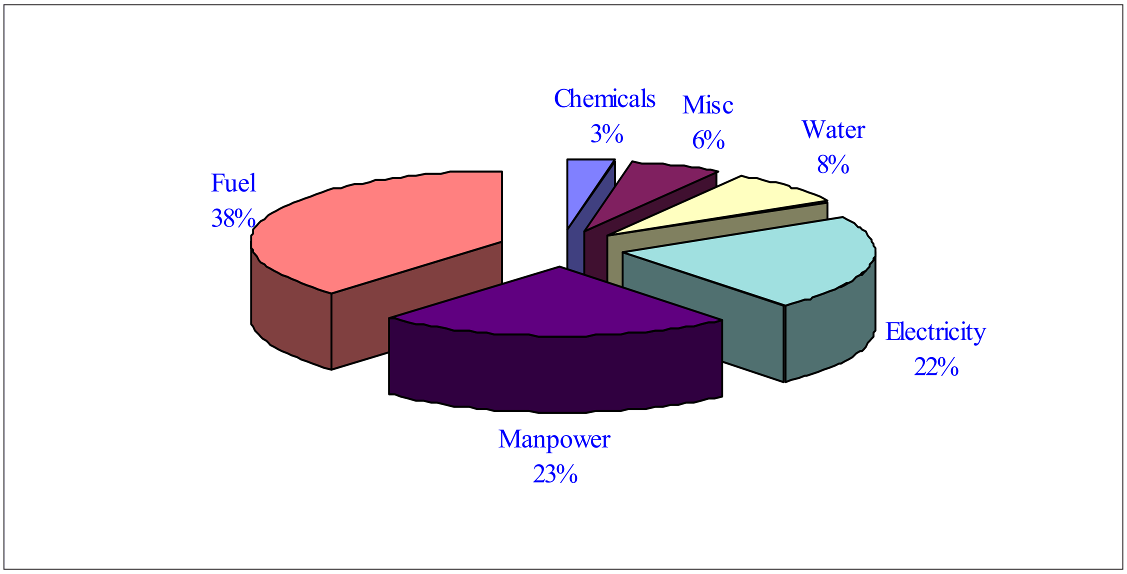
The Engineering Approach represents best practices for boilers in that it provides a benchmark for continuous improvement of our customers' systems. With the Engineering Approach we provide recommendations for optimizing total cost of operations (TCO) by considering <u>all</u> relevant factors.

Why Implement the Engineering Approach?

Individual plant management is increasingly being asked by their corporate offices to consider financial results, TCO, quality, environmental health and safety, and manpower effectiveness. The order of importance may have changed over the past few years, and may be different from industry to industry, but all plants are focusing more and more on the environment, safety, budgets, and performance.

Water treatment can have an impact on all areas of a utility budget. Actual water treatment costs, however, usually only represent 2 to 3 percent of overall costs, as seen in Figure 1. Although water treatment chemicals represent a small portion of

Figure 1. Typical Cost Distribution in the Utility Area



the utility budget, they have a major impact on all areas of a utility budget. Water touches most, if not all, of the key process units, and can have a major impact on production rates, maintenance costs, and overall plant profitability.

Unexpected boiler outages will limit, or even stop, production. Poorly run boiler systems will be very energy inefficient, and may even result in environmental problems with emissions. Additionally, running ineffectively may actually shorten boiler life, or at a minimum increase maintenance costs. In any case, plant profitability suffers, and both short- and long-term viability may be brought into question.

All is not lost, however. ONDEO Nalco's strategy is to become part of the solution, the total cost reduction solution, partnering with our customers to become a generator of profit and a reducer of total costs. Best practices, or the Engineering Approach, provide the means as well as the tools to bring this about.

Having an in-depth understanding of the mechanical components of the water systems, and specifically the boilers, provides a good starting point. The mechanical survey is then followed by statistical analysis of operational control capability, so that we have a statistical understanding of the actual control capability of the system. Finally, having a thorough understanding of the real stresses on the water chemistry of the system completes the picture.

Completing surveys of the plant, and specifically of the boiler operations with the MOC approach often leads to a new perspective on the system. Results of surveys, statistical analysis, and water chemistry modeling provide an impartial framework to evaluate and improve the overall system operation and cost.

Some examples of mechanical system aspects are heat flux, determining thermal limits, and identifying problem areas. Operational factors include examining control charts and process capability, identifying control problems, and looking at automation. Chemical aspects of the system involve looking at modeling (water chemistry, treatment chemicals, and so on), determining control limits for the system, and examining treatment alternatives.

The current approach in some plants may be to skip the mechanical and operational steps, and just focus on chemical solutions. Standard performance, basic control needs of the water chemistry, and chemical costs are what are considered. But you then have to ask whether you have total system management and whether there is reliability in the mechanical operations and recommendations. What assurances are there that chemical program success can be predicted? Are key performance factors being considered and tracked? Can total costs (and possible reductions) be calculated, or just costs associated with chemical treatment?

The Engineering Approach uses a variety of databases for data analysis. Information gathered about the system from surveys is input into the database, and is continually updated. This helps provide system management, reliability, predictability, and TCO reduction. It also allows us to benchmark and norm against other plants, other industries, and so forth.

How and what was your system designed to do? Mechanically, consider piping, blowdown tanks, and economizer. Is your system capable of operating the way you want? How and what was your current water treatment program designed to do? The Engineering Approach goes beyond MOC, however. Data, with their financial implications, are compiled so that real value is addressed.

The complete MOC approach provides an objective look at the system with information, which then helps to facilitate decisions at all levels in the plant. Choices for change are clear and documented, whether for mechanical, operational, or chemical segments of the operations. In addition, each choice has a cost and a return associated with it, allowing for project prioritization and tracking. Plant management can truly answer the questions of "how much," "how sure," and "how soon" the savings can be realized.

Probably the best way to explain the power of the Engineering Approach is to relate some real life experiences in applying the approach in our customers' plants, using plant personnel.

Examples of Best Practices – The Engineering Approach for Boilers

Boiler Water Chemistry out of the Control Box

A plant was experiencing continual out-of-specification readings for their coordinated phosphate boiler program; that is, they were frequently "out of the box" with respect to their control range. There was no immediately obvious reason for the lack of control, and it resulted in the operators making manual adjustments to the blowdown to try to improve their control. This, in turn, resulted in periodic energy and water loss through excessive blowdown, and variation in cycles of concentration.

As there was no clear reason, and it appeared to be related to boiler cycles, plant personnel started to talk about hideout. This is a serious concern, and was important to determine the real reason for the lack of control.

The Engineering Approach, looking at best practices, was chosen for problem solving. The first thing done was to complete a mechanical survey of the boiler system, focusing on everything that could be influencing the boiler reading. The feedwater system was examined, including raw water treatment, demineralization, the demineralized water storage tanks, the condensate system, and the boiler itself. The goal was to determine if there were additional unauthorized water streams being brought into the system, whether proper pretreatment was occurring, whether there was unexpected contamination, and its source, and so forth.

Following the mechanical survey, an operational survey was performed. This involved statistical analysis of the plant's control capability in critical control parameters such as pH, cycles, phosphate, chemical feed, conductivity, etc. This will help to explain why there is a control problem in this boiler system.

The parameters tested daily by the operators for feedwater, condensate, and boiler water were examined. The historical deaerator operation was looked at, as well as its maintenance logs. Historical data on condensate return and contaminant concentration were analyzed, as were resin replacement history, and regeneration practices.

All laboratory testing methods were reviewed including frequency, adherence to procedures, instrumentation, calibrations, test methods chosen, sample gathering, and so forth. This was done to make sure that the data being analyzed was statistically accurate, and that correct conclusions would be drawn.

Both ONDEO Nalco and plant personnel did the mechanical and operational surveys. This made sure that the systems were properly surveyed, and nothing was overlooked.

Finally, a chemical audit was done for the system to examine both the program choice, as well as the program application. This included feed location, sampling location, injection methods, etc. This data was examined separately, and in conjunction with the mechanical and operational survey results.

After examining all the data gathered from the various surveys, the conclusion was that there were no mechanical issues that were affecting the lack of control of the internal treatment. The chemical program being used was the technically correct choice given the feedwater pretreatment and water quality.

Furthermore, if operated properly, the system was in fact capable of being in control during a much larger percentage of the time than was being experienced (<50%). The operators were not taking the holding time of the boiler into account when making blowdown adjustments, and were often "chasing their tail" when trying to move the boiler parameters "into the box." In fact, most of the problems were caused by the operators overreacting to changes in test results from the boiler water chemistry.

The boiler was experiencing frequent load swings due to plant operation. These load swings could not be evened out due to plant configuration and requirements. Surveys also showed that the manual control of the feedwater treatment products was exacerbating the problems as manual adjustments made as the load was swinging were not necessarily timely.

Actions taken to improve the situation included operator training. Training on holding time and the length of time it would take to have a change be seen gave operators a better understanding of what was going on in the boiler system. Management and the operators agreed that, except in case of emergency, blowdown rate changes would only be made on the day shift. This allowed the plant to stop exaggerating the changes.

The feedwater treatment was also automated, providing more consistent feedwater treatment, even through large load swings for the boiler.

Results from this relatively simple "MOC" study were very positive. The percent of time the boiler spent "in the box" increased from <50% to >90%, and a project is in place to study whether it is possible to improve this further.

With the training, the operators understood the overall system much better. They were able to reduce the amount of reacting they did, and were much happier on the job. It also freed operators' time for more value-added proactive projects.

Automation improved overall system operation, and resulted in feed optimization, even with fairly large swings in steam load. This, in turn, allowed a minimization of feed—no "overfeed" was required to ensure system protection.

Additional savings were realized by the plant through optimized blowdown. This reduced both water and energy usage resulting in reduction of total cost of operation for the utility department, and improved boiler operations through consistent cycles of concentration.

Through the use of the Best Practices Engineering Approach (mechanical – operational – chemical), the plant saw good returns with a small investment in time and money. The investment was for surveys and data analysis and some automation equipment. The plant was able to eliminate hideout as a possible cause for the problem, improve overall operations, and reduce overall cost of the operation through optimization of their existing systems, rather than through a reduction in chemical price/pound. There was no quantification of what the plant saved through increased reliability and extended lifetime for the boiler.

By looking at the overall operations rather than just looking for a quick band-aid, the plant was able to quickly optimize operations and save money. This resulted in a very happy customer, an optimized system, and a better partnership between the customer and ONDEO Nalco. We were seen to provide a value-added service through our on-site technical representative acting as a consultant to the customer and using our best practices—The Engineering Approach.

Iron and Copper Corrosion in a Condensate System

A plant on the West Coast was experiencing corrosion in their condensate system. The system is primarily mild steel, although there are copper-containing portions. Due to plant operation, there are constant steam load swings resulting in pH swings in the condensate system. Both copper and mild steel corrosion were detected.

The operators adjusted the condensate treatment (neutralizing amine) to maintain acceptable pH to minimize corrosion, with the focus on mild steel.

Again, a mechanical survey was done of the condensate system, followed by looking at all the data. Steam load swings were correlated with pH swings and corrosion results. A chemical survey was also performed which looked at the particular neutralizing amine chosen, its application point, the average dosage, and the frequency of changes in dosage to maintain minimized mild steel corrosion (optimized pH). The historical copper and iron levels in the condensate were also analyzed.

The surveys indicated that no mechanical changes were needed, and that all testing procedures, equipment, calibrations, and frequency of testing were all acceptable.

When system operation was analyzed, it became apparent that the pH swings that were causing the problem would continue, and the system would continue to have sections that were at low pH (5.5-7). More neutralizing amine could not simply be added to increase the pH as this would unacceptably raise the pH elsewhere in the boiler system. This restriction needed to be taken into account in examination of the system. The chemical program chosen was not capable of properly protecting the system under the given conditions. As the operation could not change, changes to the chemical program were considered.

After careful examination of a variety of neutralizing amines (different blends, different neutralizing ability), a supplemental program was suggested. The original neutralizing amine was retained, and a new non-amine film former was chosen as a supplement in the low pH areas of the system. The product works in the pH range of 5-7, which will meet the system's mild steel protection needs in the low pH regions, but will not raise pH in other areas of the system, protecting the copper areas.

Within twenty-four hours of implementing the chemical program, both iron and copper levels in the condensate dropped dramatically. In fact plant personnel commented on the Millipore pads, and how clean they looked through the first day—from almost black, to grey, to almost clean!

Again, through a careful examination of all potential factors, a solution was arrived at that met the needs of the plant, with good results. If the operational information had not been analyzed, it is possible that the chosen solution might have been just to feed more neutralizing amine, definitely the wrong long-term overall solution.

Summary

There are many opportunities to improve overall plant as well as boiler system performance, efficiency, and safety while reducing the total cost of operations. Boiler best practices and the Engineering Approach provide useful tools to achieve these goals, and make sure that no stone is left unturned in making the system reliable. By looking at mechanical, operational, and chemical aspects of the systems, all potential problems and opportunities for improvement can be identified, whether in performance, total cost of operation, profitability, or safety.

Incorporating all aspects of the system provides a comprehensive approach. Regardless of the source, problems can be solved/prevented without creating others in other parts of the system. In fact, often starting with a mechanical survey, followed by statistical analysis of operational data, will eliminate problems that may be masking issues with the chemical treatment. Costs associated with improvements (chemical, capital, operational) can then be determined/justified, and agreement obtained from management to prioritize projects, and then track and complete them.

For more information contact:

Natalie R. Blake
ONDEO Nalco
Email: nblake@nalco.com
Phone: (630) 305-1000

Performing a Steam System Checkup: A Three-Step Checkup Identifies Potential Opportunities for Improvements

Anthony L. Wright, Oak Ridge National laboratory
Greg Harrell, University of Tennessee at Knoxville
Glenn Hahn, Spirax Sarco

Everyone knows the value of visiting the doctor for a yearly physical checkup. However, sometimes people put off this checkup – risking health problems.

To protect steam systems and ward off potential problems, operators and plant energy managers need to perform a "checkup" on their steam system. This checkup can improve the productivity and profitability of plant operations and/or assess the status of operations.

The Department of Energy (DOE) Office of Industrial Technology's (OIT) BestPractices Steam effort is developing a set of steam survey guidelines to help steam users evaluate and improve their steam systems. The guidelines focus on improvements steam users can make without relying on the help of outside consultants. Circumstances that warrant outside assistance are also identified.

Improvement opportunities in the areas of boiler efficiency, steam generation, steam distribution, steam utilization, steam losses, and heat and condensate recovery are discussed. Sample calculations and methods for estimating improvement opportunities are presented.

Plants can benefit from a three-step steam system checkup process that includes:

- Steam system profiling.
- Identifying potential opportunities for improvement.
- Reviewing maintenance practices.

The BestPractices guidelines discuss steam system profiling and identify opportunities for improvement. Maintenance practice review goes a step beyond the guidelines to ensure the plant retains any improvements.

Steam System Profiling

Profiling issues focus on utility/steam costs and calculating benefits of improvements. In steam system profiling, the first step involves a series of questions to gain a better understanding of the steam system:

- Is the fuel cost for generating steam in the system known and measured?
- Are steam/product benchmarks known and measured?
- Are critical steam system operational parameters measured?

Fuel Cost For Generating Steam

Determining the fuel cost to make steam at a facility can be an eye-opener. In many steam systems, the fuel cost can be 80% or more of the total cost to operate the steam system.

For example, if an industrial boiler generates 100,000 pounds (lb) of steam per hour, and the fuel cost to make steam is $4.00 per 1,000 lb., then the total cost for continuous steam generation for one year would be $3.5 million. If 10 percent of the fuel costs could be cut each year through operating improvements, $350,000 could be saved in energy costs.

Two methods can be used to calculate fuel costs to generate steam. The first entails calculating the fuel price, fuel energy content, steam production rate, steam energy addition and boiler efficiency. The second entails calculating the fuel feed rate per hour and the fuel price. Both methods provide a benchmark for the magnitude of energy savings possible in a steam system.

Steam/Product Benchmarking

Many industrial users measure and track steam/product benchmarks – for example, the pounds of steam needed to make a given unit of product – to benchmark their productivity. They track this benchmark with what other facilities in their company do, with what their competitors do, and with how the benchmark varies in a facility over time. Steam/product benchmarking is an excellent way to monitor productivity and the possible effect of steam system improvements on productivity.

Steam System Measurements

To monitor a steam system and diagnose potential problems, it is important to measure certain key parameters. These key parameters include boiler fuel flowrate; feedwater and makeup water flow rates; chemical input flow rates; steam flow rates (out of the boiler and at key locations in the steam system); blowdown; boiler flue gas temperature, O_2 content and CO content; boiler efficiency; steam quality out of the boiler, and condensate flow rate.

Remember, what is not measured cannot be managed.

Identifying Opportunities

This section of the checkup involves a review of some of the basic areas of steam system operation. This review can provide excellent opportunities for improving steam use and operations productivity. The opportunities discussed here fall into three areas: total steam system, boiler plant and steam distribution, and end use and recovery.

Total Steam System

The following questions will help identify operating practices and improvement opportunities for a total steam system:

- Are the steam traps in the steam system correctly selected, tested, and maintained?
- Is the effectiveness of the water treatment program reviewed?
- Are the steam system's major components well insulated?
- Are steam leaks quickly identified and repaired?
- Is water hammer in the steam system detected and eliminated?

Steam traps serve three important functions in steam systems: preventing steam from escaping from the system before its heat is used; removing condensate from the system; and venting noncondensable gases. Poor steam trap selection, testing, and maintenance can result in many system problems, including water hammer, ineffective process heat transfer, steam leakage, and system corrosion. An effective steam trap selection and maintenance program often offers paybacks in less than six months.

An effective steam system water treatment program reduces the potential for waterside fouling problems in boilers; is critical to minimizing boiler blowdown and resulting energy losses; can reduce the generation of wet steam; and greatly reduces the potential for corrosion problems throughout the steam system. Most effective water treatment programs include mechanical treatment such as filtration and deaeration, as well as chemical treatment. Problems in this area can lead to equipment failure and downtime – consultation with a chemical treatment specialist on an ongoing basis is advised.

Steam system insulation – on piping, valves, fittings, and vessels – also serves many important purposes. Insulation keeps steam energy within the system to be used effectively by processes. It can reduce temperature fluctuations in the system. Insulation also helps prevent burns to personnel.

Two main approaches are used to improve steam system insulation. The first approach is to determine the economic insulation thickness required for the operations. This can be done using a tool such as 3E-Plus software. The second approach involves system insulation surveys to identify exposed surfaces that should be insulated and/or removed, as well as any disturbed or damaged insulation.

Steam leaks can result from failures associated with improper piping design, corrosion problems, and valves. In high-pressure industrial steam systems, the energy costs associated with steam leaks can be substantial.

For example, for a steam system operated continuously, a 1,000 lb-per-hour steam leak, at a steam cost of $4.00 per 1,000 lb, would mean a yearly energy loss of $35,000. This leak rate would be expected with a 3/8-inch-diameter hole in a 300-psig steam system, or a ½-inch-diameter hole in a

150-psig steam system. Steam leak repair is essential.

Water hammer in a steam system also is a serious concern. It can lead to failure and rupture of piping and valves and, in many cases, to significant injury to personnel from contact with steam and condensate.

There are two main types of water hammer. One is caused by condensate accumulation in steam distribution piping, followed by transport of this condensate by high-velocity steam. The other is caused by a pressure pulse resulting from steam collapse (rapid condensation) in condensate return lines and heat exchange equipment. Water hammer in a steam system always necessitates repair.

Boiler Plant

These questions can help identify operating practices and improvement opportunities:

- Is the boiler efficiency measured and are the trends charted?
- Is installation of heat recovery equipment on the boilers – feedwater economizers, combustion air preheaters, blowdown heat recovery – investigated?
- Is high-quality steam generated in the boilers?

First, the major sources of inefficiency in boiler operations must be identified. The major losses in a boiler are typically associated with combustion and flue gas energy losses, blowdown losses, and refractory insulation losses. Although an understanding of blowdown and refractory insulation losses is important, these losses are not as problematic as combustion and flue gas energy losses.

Second, the efficiency of the boilers must be measured, and flue gas temperature, flue gas O_2 content and flue gas CO content also must be measured regularly. Measurement and control of excess O_2 are critical to minimizing boiler combustion energy losses. Charting the flue gas temperature trends can indicate other potential problems in the boiler. For example, elevated flue gas temperatures might indicate waterside or fireside fouling problems.
Third, if the plant runs multiple boilers, it should operate them using a strategy that minimizes the total cost to generate steam for the facility. For example, one strategy would be to use the boiler that operates with the highest efficiency for the longest possible time.

In some boilers, high flue gas temperatures and high continuous blowdown rates can provide opportunities for installation of heat recovery equipment. Feedwater economizers and combustion air preheaters can be installed, under appropriate conditions, to extract excess flue gas energy and effectively increase the boiler efficiency. Blowdown heat recovery equipment can also be installed, for some systems, to extract heat from the blowdown stream that would be otherwise lost. An economic analysis is needed to determine the feasibility of the opportunity, and qualified professionals should design and install the equipment.

The quality of the boiler steam also is important. High-quality dry saturated steam has 100 percent quality (the amount of steam divided by the total water and steam, expressed as a percentage) and contains no water droplets. Wet steam has a lower quality and contains water droplets. Generating wet steam in your boiler can cause many system problems, including inefficient process heat transfer, steam trap failures, equipment failure by water hammer, corrosion, and deposits and erosion.

Some typical causes for creation of wet steam and boiler carryover are wide swings in boiler water level, reduced operating pressure, boiler overload and poor boiler total dissolved solids (TDS) control [1]. A critical step to ensuring generation of high-quality steam is to measure steam quality out of the boiler. This typically is done using a steam calorimeter.

Steam Distribution, End Use, and Recovery

These questions will help identify operating practices and improvement opportunities for steam distribution, end use, and recovery:

- Can pressure reducing valves (PRVs) be replaced with backpressure turbines in the steam system?
- Are steam end-user needs being considered?
- How much available condensate is recovered and used?
- Is high-pressure condensate being utilized to produce usable low-pressure steam?

In many steam systems, PRVs are used to provide steam at pressures lower than those generated from the boiler. A steam system potentially can be improved by minimizing the flow of steam through PRVs. One way to do this is to replace PRVs with backpressure turbines that provide low-pressure steam and generate electricity for use. De analyses must be performed to evaluate this type of opportunity.

Steam end-user needs also must be considered. In many industrial steam systems, process steam users are being asked to handle different product parameters, including weights and dryness, process temperatures and process flows. At the same time, they are required to maintain safe and efficient operations. Steam process operators need to attend to proper equipment installation and process control, measurement of process inputs and outputs, and measurement of individual product metrics (unit of product per pound of steam needed).

Recovering and returning a substantial portion of your condensate to the boiler can have both energy and chemical treatment benefits. Condensate is hotter than makeup water, so less energy is required to convert condensate to steam. Condensate also requires significantly less chemical treatment than makeup water, so chemical treatment costs associated with returning condensate are reduced. Increased condensate return also can reduce boiler blowdown, because fewer impurities are resident in condensate, and minimize blowdown energy losses.

Reviewing Maintenance Practices

If an effective system maintenance program is in place, the operating practices and operational improvements discussed here can provide benefits to plant steam operations year after year. Major areas requiring maintenance include steam traps; boiler performance; water treatment; piping, heat exchangers, pumps, motors, and valves; and thermal insulation.

Conclusion

This article includes only some of the critical steam system areas that should be monitored and reviewed. Other important resources for improving operations include steam system consultants and service providers who can perform system assessments, troubleshoot performance problems and identify additional improvement opportunities. The DOE BestPractices Steam effort also offers tools and resources to assist steam users in improving their operations. These resources are available on DOE's website at www.oit.doe.gov/bestpractices/steam.

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For more information contact:

Glenn Hahn
Spirax Sarco
Email: ghahn@spirax.com
Phone: (610) 606-7087

Dr. Greg Harrell
Energy Management Institute
Email: gharrell@vt.edu
Phone: (423) 471-6098

Dr. Anthony Wright
Oak Ridge National Laboratory
Email: alw@ornl.gov
Phone: (865) 574-6878

The Steam System Scoping Tool: Benchmarking Your Steam Operations Through Best Practices

Anthony Wright, Oak Ridge National Laboratory
Glenn Hahn, Spirax Sarco

ABSTRACT

The U.S. Department of Energy Office of Industrial Technology (DOE-OIT) BestPractices efforts aim to assist U.S. industry in adopting near-term energy- efficient technologies and practices through voluntary technical-assistance programs on improved system efficiency. The BestPractices Steam effort, a part of the DOE-OIT effort, has developed a new tool that steam energy managers and operations personnel can use to assess their steam operations and improve their steam energy usage - the Steam System Scoping Tool. This paper describes how the tool was developed, how the tool works, and the status of efforts to improve the tool in the future.

INTRODUCTION

The U.S. Department of Energy (DOE) Office of Industrial Technology (OIT) BestPractices efforts aim to assist U.S. industry in adopting near-term energy-efficient technologies and practices through voluntary technical-assistance programs on improved system efficiency. There are nine industry groups - designated Industries of the Future (IOFs) - that are the focus of the OIT efforts. These IOFs include Agriculture, Aluminum, Chemicals, Forest Products, Glass, Metal Casting, Mining, Petroleum, and Steel. BestPractices efforts cover motors, compressed air, steam, and combined heat and power systems.

The overall goal of the BestPractices Steam effort is to assist steam users in adopting a systems approach to designing, installing, and operating boilers, distribution systems, and steam applications. BestPractices Steam is supported by a Steering Committee of steam system users, steam system service providers, and relevant trade associations. Within BestPractices Steam, a BestPractices and Technical (BPT) subcommittee works to develop tools and resources to promote the overall BestPractices Steam mission.

In the summer of the year 2000, the BPT subcommittee completed the development of and released a new tool called the Steam System Scoping Tool. This tool was developed for use by steam system energy managers and steam system operations personnel in IOF plants. The purpose of the Scoping Tool is to assist industrial users to:

- Evaluate their steam system operations against identified best practices.
- Develop a greater awareness of opportunities available for improving steam system energy efficiency and productivity.
- Compare their Scoping Tool self-evaluation results with those obtained by others.

This article describes how the Steam System Scoping Tool was developed, presents an overview of the major components of the tool, and discusses how the present version of the tools is being evaluated and used.

HOW THE STEAM SYSTEM SCOPING TOOL WAS DEVELOPED

In 1999, one of the goals the Steam BPT subcommittee set for itself was to develop a set of "Steam Assessment Guidelines" that steam users could apply to assess their steam operations. What the subcommittee initially envisioned as a set of guidelines ultimately became what is now the Steam System Scoping Tool. The authors of this paper (who co-chair the Steam BPT subcommittee) lead the activities of the subcommittee to develop the tool.

The major elements of the process that was used to develop the Steam System Scoping Tool consisted of the following:

1. An initial list of steam system best practice focus areas and questions was developed by the subcommittee co-chairs. This list was then

circulated to BPT subcommittee members for comment and addition. Subcommittee members have a variety of technical specialties - for example, boiler systems, water treatment systems, steam traps, etc. Based on subcommittee review comments the focus areas and questions were modified; this review and comment process was performed a number of times.

2. Once there was preliminary agreement on focus areas and questions, a set of possible responses to Scoping Tool questions and suggested scores for these responses were developed. Suggested scores were chosen to reflect how well a specific steam system best practice was followed in a facility. These suggested question responses and scores were again reviewed by members of the BPT subcommittee.

3. As key focus areas, questions, and score responses were developed, an approach for categorizing the focus areas and questions was developed. Based on subcommittee member input, it was ultimately decided that the main categories should be profiling, total steam system, boiler plant, and distribution/ end use/recovery.

Utilizing the expertise and input of the subcommittee members, the first evaluation version of the Steam System Scoping Tool was completed and released in August 2000.

Overview Of The Steam Scoping Tool

The present version (now called evaluation version 1.0c) of the Steam System Scoping Tool is in a Microsoft Excel spreadsheet format. The Scoping Tool includes seven individual worksheets:

1. Introduction
2. Steam System Basic Data
3. Steam System Profiling
4. Steam System Operating Practices: Total Steam System
5. Steam System Operating Practices: Boiler Plant
6. Steam System Operating Practices: Distribution, End Use, Recovery
7. Summary Results

The Steam System Scoping Tool is completed by answering the questions in Worksheets #2 through #6. When a steam user completes Worksheet #2, profiling information about the steam system is compiled. Some of the types of profiling information that can be entered into the Steam System Basic Data worksheet include:

- Total annual steam production.
- Total steam generation capacity.
- Average steam generation rate.
- Distribution of fuel sources used to make steam.
- Types of steam measurements made in the plant.
- Types of heat engines operated.

Answering the questions in Worksheets #3 through #6 assists steam users to perform self-evaluations of their steam systems. Table 1 illustrates the key improvement areas and the total scores available for those areas in the present version of the Scoping Tool. The present version of the Tool contains a total of 25 questions in the improvement areas listed in Appendix 1.

Appendix 2 shows an example screen from one of the Scoping Tool worksheets - the worksheet for Steam System Profiling. It also shows the actual questions asked in the Tool under the areas of steam costs, steam/product benchmarks, and steam system measurements, and the Tool scores available for different answers to these questions.

Once questions in Worksheets #2 through #6 are completed, the Tool automatically summarizes the answers that were provided. The user can see and print a summary of the Scoping Tool results using the Summary Results Worksheet #7.

Performing a steam system self-assessment using the Steam Scoping Tool can help users evaluate steam system operations against the best practices identified in the tool, and can help the users identify opportunities to improve steam system operations.

Through December 31, 2000, more than 100 requests have been made for the Scoping Tool.

The present version of the Tool is still being designated as an "evaluation" version because the subcommittee is attempting to obtain end user suggestions for improving it. One effort underway to get end user feedback is through a Steam Tool Benchmarking project being performed with six of the U.S. DOE Industrial Assessment Centers (IACs). There are 26 IACs, located at universities around the country, that perform comprehensive industrial assessments at no cost to small and medium-sized manufacturers. Six of these IACs - at the University of Massachusetts-Amherst, the University of Tennessee-Knoxville, Oklahoma State University, San Francisco State University, South Dakota State University, and North Carolina State University - are each performing three 1-day plant steam assessments utilizing the Steam System Scoping Tool. Feedback from these 18 steam assessments will be used to improve the present version of the Tool.

A web-based version of the Steam Scoping Tool is available through the IOF BestPractices website at www.oit.doe.gov/bestpractices/. Steam users can complete the Scoping Tool directly on line, print the results, and submit the results directly to an on-line database that is integrated with the web version of the Tool.

Future Development Efforts For The Steam System Scoping Tool

The overall vision for the continued development and usefulness of the Steam System Scoping Tool is as follows:

1. Over the next six months, user feedback will be obtained to confirm the usefulness of the Tool, and to obtain suggestions for improvements to the Tool.
2. Based on Scoping Tool results that users provide to BestPractices Steam, it will be possible to develop benchmarks of averages responses to the Scoping Tool questions.
3. Finally, the next step in the development of the Steam Scoping Tool is to expand its capabilities - so that, when steam users find areas where improvement is needed, the Tool will provide guidance to the users.

Conclusions

The Steam System Scoping Tool was developed to encourage steam system energy managers and operations personnel to evaluate their steam system operations and develop a greater awareness of opportunities that may be available for improving energy efficiency and productivity. In addition, steam users are encouraged to provide their Scoping Tool results to BestPractices Steam, so that results from the users can be summarized. All Scoping Tool results obtained from steam users will be held in strict confidence.

Acknowledgments

BestPractices Steam would like to thank and acknowledge **Spirax Sarco Inc.** for co-directing the overall effort to develop the Steam Scoping Tool, and the following organizations who participate on the Steam Best Practices and Technical subcommittee and who assisted in reviewing and developing the Scoping Tool:

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Construction Engineering Research Lab
Dupont
Electric Power Research Institute
Enbridge Consumers Gas in Canada
Enercheck Systems, Inc.
Energy Research and Development Center
Institute of Textile Technology
Iowa Energy Center
Institute of Paper Science and Technology
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Sappi Fine Paper, North America
Virginia Polytechnic Institute
Washington State University

For more information contact:

Glenn Hahn
Spirax Sarco
Email: ghahn@spirax.com
Phone: (610) 606-7087

Dr. Anthony Wright
Oak Ridge National Laboratory
Email: alw@ornl.gov
Phone: (865) 574-6878

OIT Clearinghouse
Email: clearinghouse@ee.doe.gov
Phone: (800) 862-2086

APPENDIX 1. Summary Of Key Improvement Areas And Available Scores In The Steam System Scoping Tool

IMPROVEMENT AREA	WHAT TO DO	AVAILABLE SCORE
	STEAM SYSTEM PROFILING	
Steam Costs	Identify what it costs at your facility to produce steam (in units of $/1000 lbs) and use this as a benchmark for evaluating opportunities for improving your steam operations. Start by determining what your fuel costs are to make steam, then add other costs associated with your operations (chemical costs, labor, etc).	20
Steam/Product Benchmarks	Identify how much steam it takes to make your key products. Then track this benchmark: a) with what other facilities in your company do; b) with what your competitors do; and c) with how this benchmark varies in your operations over time.	20
Steam System Measurements	Identify key steam operational parameters that you should monitor and ensure that you are adequately measuring them.	50
	STEAM SYSTEM OPERATING PRACTICES	
Steam Trap Maintenance	Implement a comprehensive program to correctly select, test, and maintain your steam traps.	40
Water Treatment Program	Implement and maintain an effective water treatment program in your steam system.	30
System Insulation	Ensure that the appropriate major components of your steam system are well insulated. Determine the economic insulation thickness for your system components, and perform system insulation reviews to identify exposed surfaces that should be insulated and/or unrestored or damaged insulation.	30
Steam Leaks	Identify and quickly repair steam leaks in your steam system.	10
Water Hammer	Detect and quickly eliminate water hammer in your steam system.	10
Maintaining Effective Steam System Operations	Establish and carry out a comprehensive steam system maintenance program.	20
	BOILER PLANT OPERATING PRACTICES	
Boiler Efficiency	Measure/trend/look for opportunities to improve your boiler efficiency.	35
Heat Recovery Equipment	Evaluate installation of heat recovery equipment in your boiler plant.	15
Generating Dry Steam	Ensure that you generate high-quality dry steam in your boiler plant.	10
General Boiler Operation	Ensure that your boilers perfrom their functions without large fluctuations in operating conditiions.	20
	STEAM DISTRIBUTION, END USE, RECOVERY OPERATION PRACTICES	
Minimize Steam Flow Through PRVs	Investigate potential to replace pressure-reducing valves with back-pressure turbines in your steam system.	10
Recover and Utilize Available Condensate	Determine how much of your available condensate you recover and utilize.	10
Use High-Pressure Condensate to Make Low-Pressure Steam	Investigate use of high-pressure condensate to produce useable low-pressure steam.	10
	TOTAL AVAILABLE STEAM SCOPING TOOL SCORE	**340**

APPENDIX 2. Steam Scoping Tool Example Screen - Steam System Profiling

Steam Costs

What To Do Identify what it costs at your facility to produce steam (in units of $/1000 lbs.), and use this as a benchmark for evaluating opportunities for improving your steam operations. Start by determining what your fuel costs are to make steam, then add other costs associated with your operations (chemical costs, labor, etc.)

Why Important Understanding the cost to make steam can be an eye-opener—producing steam is not free! Any opportunity that reduces the amount of steam generated saves money, so understanding the cost to make steam is a key step to being able to quantify improvement opportunities.

	ACTIONS	SCORE	YOUR SCORE
Do you monitor your fuel cost to generate steam in terms of ($) / (1000 lbs. of steam produced)?	yes	10	
	no	0	
How often do you calculate and trend your fuel cost to generate steam?	at least quarterly	10	
	at least yearly	5	
	less than yearly	0	

Steam/Product Benchmarks

What To Do Identify how much steam it takes to make your key products. Then track this benchmark: a) with what other facilities in your company do; b) with what your competitors do; and c) with how this benchmark varies in your operations over time.

Why Important The bottom line of your operation is how effectively you make your products, and steam use has an impact on your productivity. Steam/product benchmarking is an excellent way to monitor productivity and how steam improvements translate to improved productivity.

	ACTIONS	SCORE	YOUR SCORE
Do you measure your steam/product benchmark in terms of lbs. of steam needed/unit of product produced?	yes	10	
	no	0	
How often do you measure your steam/product benchmark - in terms of lbs. of steam needed/unit of product produced?	at least quarterly	10	
	at least yearly	5	
	less than yearly	0	

Steam System Measurements

What To Do Identify key steam operational parameters that you should monitor and ensure that you are adequately measuring them.

Why Important You can't manage what you don't measure! Measurement of key steam system parameters assists you in monitoring your system, diagnosing potential system problems, and ensuring that system improvements continue to provide benefits to your operations.

	ACTIONS	SCORE	YOUR SCORE
Do you measure and record critical energy?			
Steam Production Rate (to obtain total steam)	yes	10	
Fuel Flow Rate (to obtain total fuel consumption)	yes	6	
Feedwater Flow Rate	yes	6	
Makeup Water Flow Rate	yes	4	
Blowdown Flow Rate	yes	2	
Chemical Input Flow Rate	yes	2	
	no to all above	0	
How intensely do you meter your steam flows? CHOOSE ONE OF FIVE ANSWERS	by major user/ equipment	20	
	by process unit	10	
	by area or bldg.	5	
	by entire plant	2	
	not at all	0	

The Enbridge Consumers Gas "Steam Saver" Program

Bob Griffin, Enbridge Consumers Gas

ABSTRACT

This paper describes the Enbridge Consumers Gas Steam Saver Program. It gives results for a four-year period up to the end of December, 2000. It was presented at the March 2001 Energy conference sponsored by CIPEC, Natural Resources Canada and The Canadian Auto Parts Manufacturer's Association.

In Canada, medium-sized and large-sized steam plants consume approximately 442 billion cubic feet (12.5 billion cubic metres) of natural gas annually. This is 25% of all natural gas delivered to all customers. (Small steam plants and hydronic heating boilers consume another 15 percent.)

Enbridge Consumers Gas, a local gas distribution company located in Toronto, has approximately 400 industrial and institutional customers who own medium-sized or large-sized steam plants.

During the past four years, Enbridge has developed a comprehensive steam energy efficiency program called "**Steam Saver.**" This program is aimed at these 400 customers. The heart of this program is the boiler plant audit and performance test.

This paper describes the fuel-saving results for 41 medium-sized and large-sized boiler plants where audits have been completed and projects have been implemented.

INTRODUCTION

Enbridge Consumers Gas is a natural gas distributor whose franchise service area includes the Greater Toronto area, Ottawa, Eastern Ontario and the Niagara Penninsula. The gas utility has 1.4 million customers including 1200 large volume customers.

In 1994, the Ontario Energy Board required the two main gas utilities in this province to implement energy efficiency programs.

In 1997, Enbridge Consumers Gas introduced the "Steam Saver Program," a boiler plant audit which is aimed at large volume industrial and institutional customers with steam plants.

Since 1997, 41 steam plants have been audited and 1.4 billion cubic feet (40 million cubic metres) of energy-saving opportunities have been identified. This represents 12 percent of the total natural gas consumed by these plants.

In 1999, several **new programs** were introduced to focus on other opportunities to save steam energy. These programs include Steam Trap Surveys, Steam Pressure Reduction, Combustion Tune-ups and Plant Metering. These new programs have identified further savings.

The role of the gas utility is to facilitate the identification and implementation of fuel-saving projects. The utility is in a unique position to do this by virtue of its existing sales force, knowledge of the market, and its reputation for providing unbiased technical assistance.

THE PRICE OF NATURAL GAS

Since the beginning of this program, the price of natural gas and other fuels to large industrial customers has increased dramatically. As a consequence, the average financial payback period for the entire range of steam-saving projects identified has dropped from three years to a simple payback of 1.1 years:

Year	Burner Tip Price of Nat. Gas ($ per CU M)	Average Payback on Steam Saving Prj.
1997	$0.10	3.1 years
1998	$0.12	2.7 years
1999	$0.16	2.0 years
2000	$0.30	1.1 years

THE STEAM BOILER POPULATION

Ontario is the most heavily industrialized province in Canada. With a population of 12 million people and an industrial base of some 5000 manufacturing companies (larger than 50 employees), it can be compared in size and industrial output with Michigan or Ohio.

All major industrial sectors are represented. The automotive, pulp and paper and steel industries are particularly large energy and steam users. Food and beverage processors and the petrochemical industry are also heavy steam consumers.

The Enbridge Consumers Gas franchised service area includes approximately one-third of the Province's industry and half of its large institutions.

Fuel Consumption in Boiler Plants

While the foucs of Enbridge's efforts to improve efficiency in steam plants is natural gas, steam efficiency can equally be applied to plants which burn other fuels. Any of the efficiency programs described here can be applied to oil, wood, or coal fired plants.

TABLE 1: Boiler Population for Steam Plants with Annual Fuel Consumption Greater Than 70 Million Cubic Feet (2 million cubic metres) of Natural Gas

Location	No. of Boilers	No. of Plants	Annual Gas Consumption BCF/YR	Annual Gas Consumption B CU M/YR
Enbridge	1,330	400	66 BCF/YR	1.9 B CU M/YR
Ontario	4,000	1,200	177 BCF/YR	5.0 B CU M/YR
Canada	10,000	3,000	442 BCF/YR	12.5 B CU M/YR

Note: All figures exclude large electric utility plants. BCF/YR = Billion Cubic Feet per Year B CU M/YR = Billion Cubic Metres per Year

The Steam Saver program is aimed at industrial consumers and also medium-sized and large-sized institutions such as hospitals, defense bases and universities. These facilities have central heating plants which are increasingly moving to co-generation to supplement steam production and absorption chilling to level out the seasonal demand.

In Ontario, fuel consumption in the target market (medium-sized and large-sized plants) breaks down approximately as follows:

TABLE 2: Fuel Consumed by Medium-sized and Large-sized Boiler Plants--Ontario

	Equivalent BCF	Percent of Total
Natural Gas	177	65%
Oil	50	18%
Wood	40	15%
Coal/other	5	2%
Total	**272**	**100%**

Note: Most plants burning wood co-fire with natural gas. Most oil is consumed by customers with interruptible gas contracts operating under gas curtailment conditions.

The "Steam Saver" Program

The Regulatory and Financial Background

The Ontario Energy Board (O.E.B.) is the regulating agency for the two gas utilities and the electric utilities in this Province. In 1994, the O.E.B. required the gas utilities to implement energy efficiency programs for all market sectors. In 1999, the O.E.B. and Enbridge negotiated a special financial arrangement called the "Shared Savings Mechanism". This arrangement sets targets in terms of natural gas volumetric savings which must be implemented by Enbridge each fiscal year. If Enbridge fails to meet the annual target, it pays a heavy financial penalty which is levied through the rate base. On the other hand, if the utility exceeds the target, it receives a significant financial reward by the same means. The penalty or reward is directly proportional to the energy efficiency volume shortfall or excess compared to the target figure. The formula for calculating the penalty or reward is complex. In general it is based on the estimated societal benefits. Enbridge's share of the total benefit is a percentage of the total figure. This arrangement has provided a major financial incentive for Enbridge to implement energy efficiency programs.

Description of the Steam Saver Program

The Steam Saver Program began in 1997 as a single activity-the steam plant audit and performance test. It has since been expanded to include specific programs designed to achieve savings sooner, for smaller customers, and at less cost. The performance test and audit is still the largest activity but programs such as the Steam Trap Survey are generating rapidly growing results. A new program, The Combustion Tune-up Program, has received an excellent early response from customers.

The Steam Plant Performance Test and Audit

<u>Why Do a Boiler Plant Audit?</u> The purpose of the steam plant performance test and audit is:

- To identify fuel savings opportunities
- Provide economic data to the customer (Benchmarking)

<u>Who Qualifies for an Audit?</u> All customers having boiler plants which consume more than 2 million CU M/YR (70 million CU FT/YR) or more of natural gas qualify.

<u>Who is Responsible for the Audit?</u> After the Enbridge Energy Management Consultant (EMC) sells an audit to a customer he assumes the project responsibility for organizing the field work and coordinating the report.

Enbridge contracts with outside specialized steam engineering consultants to do the audit, but participates in the testing and site work. Enbridge supplies and maintains combustion analyzers and other test equipment.

<u>How is an Audit Done?</u> The audit field work and report proceed according to a standard format (which can be tailored for specific customer requirements and circumstances). Here is the standard procedure and report format which has been developed over three years:

1. ***Field Work First*** -This is a crucial part of the process. The auditors must establish a friendly relationship with the plant management and operators. There is often an air of suspicion in boiler plants because of the fear of criticism or job loss. The watchword here is diplomacy.

The Enbridge EMC spends two or three days in the customer's plant with the outside engineering consultant.

Combustion Tests are done on all boilers taking combustion and temperature readings at four or five points between low and high fire.

The boiler plant is inspected with a view to identifying problems or losses. Features such as economizers, air pre-heaters, blow down heat recovery, excessive venting and instrumentation are all considered.

The boiler plant supplies its records to the auditors. These may include a wide variety of daily or monthly operating reports, operators' logs, water treatment records and even previous test reports. Many plants have very poor records or almost none at all.

2. *The Audit Report* - The audit report is completed by the steam consulting engineer together with the Enbridge EMC who usually writes part of the report.

The standard report comprises eight sections as follows:

Executive Summary

A listing of energy saving opportunities complete with savings and capital cost estimate.

Section 1-Plant Energy History
A summary of operating data for the past year. We rely heavily on the hourly gas consumption information from the utility gas meter (The Metretek System). Combustion test results and steam plant log data are also employed. The result is a comprehensive report on fuel consumption, steam production, peaks and averages, blow down rate, water make-up, electricity and so on.

This section also includes cost data and benchmarking for the larger plants.

Section 2-Equipment List
Nameplate and rating data from all boilers and other major equipment in the plant.

Section 3-Combustion Test Data
Calculation of losses using the ASME power test code method and efficiency graphs for all boilers.

Section 4-Plant Inspection Report
Observations and comments on the plant design, equipment condition, and suggestions for improvements to save energy

Section 5-Steam Loads and Distribution
Observations about the steam distribution system and comments on the nature of loads. Spot obvious opportunities to save such as excessive venting of condensate receivers, condensate not returned, uninsulated piping and so on.

Section 6-Water Treatment
A general review of the water treatment records. Comments on blow-down, maintaining target levels of sulphite, PH and alkalinity.

Section 7-Savings and Capital Cost
Calculations showing the savings estimates for each project.

Section 8-Safety Issues
Comments on conditions such as high carbon monoxide levels in flue gas, natural gas leakage and steam leakage.

The Cost Of Doing A Steam Plant Performance Test And Audit

The following is the average direct cost of 41 audits completed to date. It excludes administrative and marketing costs.

Steam Engineering Consultant Fee	$ 8,500
Travel Expenses	$ 600
Enbridge EMC's Time	$ 4,250
Total	$ 13,350

Note: The Average Hourly Rate is $ 85/HR

Enbridge pays two thirds of the consultant fee up to a maximum of $5,000. On average, therefore, Enbridge pays the maximum of $5000 and the customer pays $3,500 for the audit.

Results Of 41 Steam Plant Performance Tests And Audits

The results of 41 steam plant audits performed since 1997 are shown in Table 3 (see next page). Twenty six of the audits were industrial customers. The remaining 15 customers are central heating plants in hospitals, universities, one national defense base and other federal government facilities.

Where Do The Savings Come From?

Table 4 (located on page 35) provides a breakdown of the results of the steam plant audits and other programs by type of project.

The top projects in terms of savings identified are:

Boiler Room Capital Projects

The payback on major boiler replacement projects is now 3.2 years, down from 7.5 years in 1999. Enbridge's role in affecting energy savings is to work with customers who are making major investments at the planning stage in order to provide technical and financial assistance to optimize efficiency. Boiler sizing and selection, heat recovery, metering, and other decisions come into play.

Combustion Improvements

Combustion improvements are almost universally required. The payback on projects such as boiler tune-up, repair of burners, fuel air ratio components and blowers is less than one year.

Heat Recovery Projects

New economizers, blow-down heat recovery and condensing heat recovery projects identified the largest single category of improvement. The average payback of 1.1 years is very attractive.

Steam Distribution System Improvements and Trap Repair

Trap repairs, replacement, improved condensate return and other projects are an attractive investment with an average simple payback of 0.4 years.

NEW STEAM SAVER PROGRAMS

Several new Steam Saver programs were introduced in 1999. The purpose was to take advantage of the findings of the Steam Plant Audits which are summarized in Table 4; that is, to target the main savings areas without having to conduct an expensive study oF the boiler plant. This also allows Enbridge to extend the Steam Saver Program to smaller plants and to reduce the sales/implementation cycle time.

The Steam Trap Survey

The steam trap manufacturers have considerable technical expertise in the application and testing of steam traps.

TABLE 3: Total Results Of Steam Plant Performance Tests And Audits Excluding New Programs For 1999

	Units	Metric Equivalent
Number of Plants Audited	41	____
Annual Gas Vol. Consumption	11.8 Billion CU FT/YR	333 Million CU M/YR
Annual Gas Bill	$100 Million	____
Number of Savings Projects Identified	203	____
Annual Fuel Savings Identified	1.4 Billion CU FT/YR	40.1 Million CU M/YR
Annual Dollar Savings Identified	$ 12.0 Million	____
Per Cent Savings of Annual Gas Bill	12%	____
Capital Cost of Projects Identified	13.5 Million	____
Average Payback of Projects Identified	1.1 years	____
Number of Savings Projects Implemented	39	____
Annual Gas Vol. Savings Implemented	378 Million CU FT/YR	10.7 Million CU M/YR
Annual Dollar Savings Implemented	$ 3.2 Million	____

Many steam distribution systems are poorly designed and maintained, resulting in major losses of energy in steam and condensate.

Our approach has been to team up with the steam trap manufacturers, including Spirax Sarco, Preston-Phipps (Armstrong) and Nutech (TLV) to conduct steam trap surveys.

Enbridge funds 50% of the survey cost. The survey is conducted by the supplier's technicians.

This includes tagging all traps, testing all traps and providing a critique of the system design problems where applicable.

Besides leaking traps, there are a range of common problems found:

- Condensate return pump failure and condensate dumping to drain.
- Condensate return lines too small causing back-up of condensate into coil or heat exchanger.

TABLE 4: Steam Saver Programs Summary of Results By Type of Project

NORMALIZED FUEL COST $0.30 PER CU M

NO.	TYPE OF PROJECT	IDENTIFIED SAVINGS: NO. OF PROJECTS IDENTIFIED	IDENTIFIED SAVINGS: ANNUAL DSM SAVINGS CU M / YR	IDENTIFIED SAVINGS: ANNUAL SAVINGS $	IDENTIFIED SAVINGS: TOTAL CAPITAL INVESTMENT	AVERAGE PAYBACK YEARS	PROJECTS IMPLEMENTED: ANNUAL SAVINGS CU M/YR	PROJECTS IMPLEMENTED: ANNUAL SAVINGS $/YR
BOILER PLANT AUDITS								
1	**Combustion Improvements** Boiler tune-up, Combustion control repair, Burner repair, Repair existing oxygen trim system	45	6,076,909	$1,823,073	$725,700	0.40	3,065,890	$919,767
2	**Boiler Room Capital Projects** Replace old boiler, add summer boiler, change feed-water pump, new feedwater system, new deaerator, new flue gas uptake damper, turbine repair, controls improvements	43	7,384,603	$2,215,381	$7,022,400	3.17	2,862,507	$858,752
3	**Heat Recovery and Economizer Projects** Add new economizer, repair existing economizer, add new condensing heat recovery economizer, add new blow down heat recovery system	37	1,809,148	$3,542,744	$4,054,322	1.14	1,973,473	$592,042
4	**Operating Changes in Boiler Room** Reduce deaerator venting, reduce boiler blow-down, shut down boilers on weekends and off-hours, use existing F.W. turbine, fewer boilers operating	22	4,305,097	$1,291,529	$112,732	0.09	1,791,242	$537,373
5	**Steam Distribution Piping and Condensate Improvements (Excluding Steam Trap Program)** New steam piping, new condensate piping and receivers, consolidate steam piping of different pressures, repair condensate pumps, new control valves, recover flash steam from tanks, includes repairs to steam process equipment	37	6,658,379	$1,997,514	$686,500	0.34	1,020,457	$306,137
6	**Building HVAC Changes and Capital Projects** New air handler controls, new temperature set back controls, close building doors in winter, turn off steam heaters in summer, convert steam coils to direct firing-natural gas	7	2,535,190	$760,557	$490,000	0.64	0	$0
7	**Insulation Improvements** Insulate oil storage tanks, insulate steam piping	3	885,650	$265,695	$286,000	1.08	0	$0
8	**Other Projects** Clean boiler waterside, improve water treatment, clean heat exchangers	9	405,000	$121,500	$75,000	0.62	0	$0
TOTAL BOILER PLANT AUDITS		**203**	**40,059,976**	**$12,017,993**	**$13,452,654**	**1.12**	**10,713,569**	**$3,214,071**
9	**Steam Pressure Reduction** Central Heating Plants	6	1,814,490	$544,347	$0		1,814,490	$544,347
10	**Steam Trap Survey Program**	38	4,116,753	$1,235,026	$548,961		2,327,712	$698,314
11	**New Boiler Plant Program**	2	525,000	$157,500	$1,307,352		400,000	$120,000
12	**Metering and Monitoring Program** Install new steam, gas, water meters, repair and calibrate existing, install computerized data acquisition system	2	476,000	$142,800	$185,000		476,000	$142,800
TOTAL OTHER PROGRAMS		**48**	**6,932,243**	**$2,079,673**	**$2,041,313**		**5,018,202**	**$1,505,461**
TOTAL RESULTS BY TYPE OF PROJECT		**251**	**46,992,219**	**$14,097,666**	**15,493,967**	**1.10**	**15,731,771**	**4,719,531**

- Wrong type of trap for the application, oversized or undersized traps.
- No strainers.
- Missing piping insulation.

TABLE 5. Results of Steam Trap Surveys

Number of Sites Surveyed	38
Number of Traps Tested	4,834
Number of Leaking Traps	869
% of Traps Found Leaking	18%
Annual Steam Losses	111,751,570 LB/YR
Identified Fuel Savings	$ 1,235,025
Capital Investment	$ 548,961
Average Simple Payback	0.4 Years
Projects Implemented	19
Savings Implemented	$ 698,313

The Steam Pressure Reduction Program

This program is aimed at central heating plants where steam is produced at 100 to 250 psig, distributed to remote locations, and then reduced in pressure to 15 psig or lower.

Theoretically, energy is saved when the main steam pressure is reduced because:

- The boiler stack temperature is reduced.
- Piping radiation losses are reduced
- Leaks in traps and other sources are reduced.

The success of this measure depends on the fact that most central heating plants are over-sized. Boiler tubes and steam piping can accommodate the increase in the specific volume of the steam without undue pressure loss. We have conducted initial tests at six plants and are now monitoring the benefits over a longer period. The true savings have ranged from 3 percent of the total gas consumption to 8 percent in one case. It appears that savings are greatest when the pressure is reduced below 70 psig.

The New Boiler Plant Program

The boiler population is aging. In Ontario, records indicate that the average age of registered steam boilers is 26 years.

Most new boilers sold are for replacement, although there are a few green-field boiler plant projects every year.
Many replacement boilers are installed without proper analysis, planning or attention to energy efficiency features.

The Enbridge New Boiler Program is designed to motivate owners to plan properly and consider energy saving features. This program provides financial incentives to companies who plan to install new or replacement boilers if they include the following package of energy efficiency measures:

1. ***Right Sizing the Boilers*** - In the past, boiler plants were much oversized by design. This was justified on the basis of future growth. Many plant owners are now paying a high penalty for the added losses of operating the boiler plant on low fire.

Enbridge offers technical help to customers in sizing based on load analysis and fuel consumption history. We have unique expertise in forecasting plant and heating loads and apply this experience at no charge to customers who are planning replacement or expansion of boiler plants.

2. ***Economizers*** - Economizers can improve annual boiler efficiency by as much as 5 percent. However an engineering analysis which takes account of the load profile is required to correctly estimate the savings attributable to the additional investment required to install an economizer.

3. ***Blow Down Heat Recovery*** - Part of the New Boiler Plant package is to consider implementing blow-down heat recovery in the new boiler plant.

4. ***Fuel and Steam Metering*** - One of the most neglected areas of the boiler plant is metering. New plants are encouraged to invest in steam and fuel metering. This is part of the incentive package offered to owners of new boiler plants.

The Boiler Combustion Tune-Up Program

Unnecessary combustion losses account for nearly 2 percent of the total fuel consumed by steam boiler plants. There is an existing infrastructure of boiler service companies who are capable of testing and repairing boiler combustion problems.

This program is designed to encourage steam plant owners to maintain the combustion of their boilers through their present boiler service companies or to do it themselves.

Enbridge has designed a program which pays the owner to test and tune-up his boilers twice per year.

The terms of this program are that the owner must submit combustion test results in order to be paid. The incentive grant is:

- $ 130 per boiler per tune-up for boilers smaller than 600 boiler horse power
- $ 230 per boiler per tune-up for boilers 600 boiler horsepower and larger.

Metering and Energy Management for Boiler Plants

Metering of fuel and steam is an often-neglected aspect of steam plant operation. The boiler plant should be regarded by corporate management as a cost center.

Fuel now accounts for 85 percent of the cost of operating a boiler plant.

It is imperative in most cases that the fuel input to the boiler plant be reported regularly. This is a bare minimum for responsible cost management, yet this requirement is often not met.

Low cost data acquisition systems make it feasible to automatically collect fuel consumption and other boiler plant data and produce regular reports for management use.

The average cost of operating a large boiler plant according to Steam Saver audits of manned plants is over $5 million per year. Enbridge offers incentive grants to steam plant operators who are prepared to install metering and energy management systems.

Conclusions

In the past three years, The Steam Saver Program has demonstrated that, on average, fuel savings of 14 percent of total annual fuel consumption can be achieved. The 251 projects identified in 89 plants have shown an average payback of 1.1 years.

73 of these projects saving 554 million cubic feet (15.7million cubic metres) of natural gas annually have been implemented. This represents 4 percent of total fuel consumption. Enbridge customers are saving $4.7 million annually on these projects.

The rate at which savings are identified and implemented is growing rapidly. This is due to:

TABLE 6: Total Results Of Steam Saver Program Including New Programs to End of Year 2000

	Units	Metric Equivalent
Total Number of Plants	41 + 48	____
Number of Savings Projects Identified	251	____
Annual Fuel Savings Identified	1.7 Billion CU FT/YR	42 Million CU M/YR
Annual Dollar Savings Identified	$14.1 Million	____
Savings % of annual Gas Bill	14%	____
Capital Cost of Projects Identified	$ 15.5 Million	____
Average Payback of Projects Identified	1.1 Years	____
Number of Savings Projects Implemented	73	____
Annual Gas Vol. Savings Implemented	554 Million CU FT/YR	15.7 Million CU M/YR
Annual Dollar Savings Implemented	$ 4.7 Million	____

- The growing effectiveness of the Enbridge Energy Management consultants.
- Capital projects require an average of 18 months to implement. There are more projects in the pipeline now after four years of conducting audits.
- Recently, the rapid rise in natural gas prices which has motivated plant owners to better manage their energy costs.
- New programs introduced in 1999 were designed to accelerate the process of implementing energy saving projects. These are now showing results.

The best projects for saving energy in a steam plant are:

- Combustion improvements.
- Heat recovery projects.
- Steam trap and distribution system maintenance and repair.
- Boiler replacement with proper sizing, selection, and metering.

Steam Cost And Plant Benchmarking

The steam plant audits include a feature which provides each customer with an estimate showing the cost of steam and other plant operating variables, compared to the average steam plant. This is a useful tool for management to benchmark their operation. The average cost of steam for 15 large steam plants in year 2000 was $13.72 per thousand lb. This is an increase of 70 percent over 1999. Table 7 (see next page) gives details on average and total steam costs for these plants.

For more information contact:

Bob Griffin
Enbridge Consumer Gas
Email: robert.griffin@cgc.enbridge.com
Phone: (416) 495-5298

TABLE 7 - Steam Cost

Average Cost and Performance for 15 Large Boiler Plants
Year 1999 vs. Year 2000

FUEL COST →	Cost for Year 1999 $0.16 Per CU M	Cost for Year 2000 $0.30 Per CU M

AVERAGE PLANT PERFORMANCE

Date of Audit	1997 to 2000	1997 to 2001
Type of Steam Load	Heating and Process	Heating and Process
Installed Boiler Capacity (LB/H)	163,560	163,560
Rated input of "ON" boilers (BTU/HR)	113,329	113,329
Annual Gas Consumption (MILLION CU M)	14.6	14.6
includes equivalent btu value of oil		
Average Hourly Gas Cons. (CU M/HR)	1,689	1,689
Peak Hourly Gas Consumption (CU M/HR)	3,125	3,125
Operating Hours/YR	8,640	8,640
Average Combution Efficiency (%)	82.00%	82.00%
Average Plant Efficiency (%)	77.00%	77.00%
Operating Pressure (PSIG)		
Total Enthalpy at Operating Pressure		
Steam Net Added Enthalpy for Site (BTU/LB	1,204	1,204
Annual Steam Production (LB)	1,052	1,052
Average Hourly Steam Poduction (LB/HR)	369,750,784	369,750,784
Peak Hourly Steam Load (LB/HR)	43,019	43,019
Make-up Water Annual Consumption	80,451	80,451
MILLION IMP. GAL.	19.2	19.2
Electricity Annual Consumption (KWH/YR)	1,149,957	1,149,957
Average Blow-Down Rate	5.60%	56.0%
Blow-Down Heat Recovery		
Estimated Vent Losses (BTU/HR x 1000)	300	300

Steam Cost	Total Annual Cost 15 Sites Yr 1999	Annual Average Cost per Site	Average Total Cost/KLB	Annual Cost 15 Sites Yr 2000	Annual Average Cost Per Site	Average Cost/KLB
FUEL	$34,628,550	$2,308,570	$6.244	$64,928,531	$4,380,000	$11.846
Electricity	$1,184,829	$78,989	$0.214	$1,184,829	$78,989	$0.214
Water	$810,006	$54,000	$0.146	$810,006	$54,000	$0.146
Water Treatment Chemicls	$627,484	$41,832	$0.113	$627,484	$41,832	$0.113
Operating Labor	$4,555,827	$303,722	$0.821	$4,555,827	$303,722	$0.821
Total Operating Cost	**$41,806,696**	**$2,787,113**	**$7.538**	**$72,106,677**	**$4,858,543**	**$13.140**
Maintenance Costs						
Mtce. Lobor (internal)						
Mtce. Contracts incl parts and labor						
Subtotal Maintenance Cost	$3,005,028	$214,645	$0.581	$5,634,428	$214,645	$0.58
Total Annual Operating Cost	**$44,811,724**	**$3,001,758**	**$8.118**	**$77,741,105**	**$5,073,188**	**$13.72**

A Highly Successful Holistic Approach to a Plant-Wide Energy Management System

Frederick P. Fendt, P.E., Rohm and Haas Company

Abstract

In the course of more than twenty years as an engineer involved directly in utility related projects in a number of industries, I have seen a great variety of energy efficiency projects and programs covering the entire spectrum of efficacy. The Deer Park, Texas, plant of the Rohm and Haas Company has a unique energy management program that has proven to be highly successful. This program has resulted in a 17 percent reduction in energy use on a per pound of product basis, saving 3.25 trillion btus and $15 million each year! This article discusses this program, its history, successes, and the unique characteristics that have contributed to those successes.

The Rohm and Haas Company

For more than 90 years, Rohm and Haas has been a leader in specialty chemical technology. Our chemistry is found today in paint and coatings, adhesives and sealants, household cleaning products, personal computers and electronic components, construction materials and thousands of everyday products. In every corner of the world, Rohm and Haas products are "Quietly Improving the Quality of Life.™"

Rohm and Haas Company is one of the world's largest manufacturers of specialty chemicals – technologically sophisticated materials that find their way into applications in a variety of major markets. Most Rohm and Haas products are never seen by consumers; rather, they are used by other industries to produce better-performing, high quality end-products and finished goods. The history of Rohm and Haas has been a series of innovative technical contributions to science and industry, usually taking place behind the scenes.

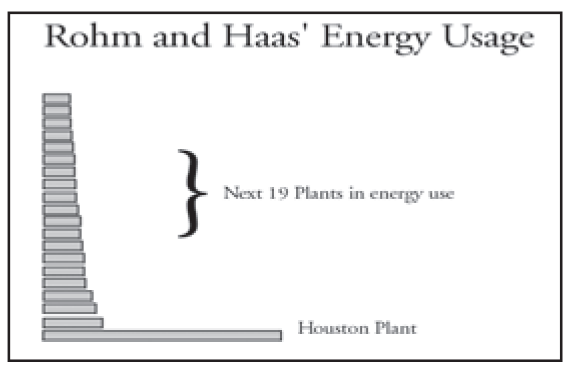
In 1999, Rohm and Haas acquired two great companies – LeaRonal, a maker of electronic chemicals, and Morton International, a global producer of specialty chemicals and salt. These acquisitions helped grow the company into today's Rohm and Haas, with sales of $6.5 billion and more than 20,000 employees. It operates approximately 150 research and manufacturing locations in 25 countries.

Rohm and Haas is committed to sustainable development and has pledged to strive to ensure that operations and products meet the needs of the present global community without compromising the ability of future generations to meet their needs. Economic growth, environmental protection and social responsibility are integral considerations in the company's business decisions.

Rohm and Haas' Deer Park Facility

The Rohm and Haas Deer Park, Texas, facility has operated for over 52 years and is located on the Houston Ship Channel approximately 22 miles east of downtown Houston. The site is over 900 acres and employs more than 800 people. It serves as Rohm and Haas Company's flagship plant and is the largest monomer manufacturer for key Rohm and Haas products. The plant manufactures in excess of 2 billion pounds of chemical products annually including methyl methacrylate and various acrylates. Accordingly, this plant, alone, accounts for approximately 35 percent of all Rohm & Haas' corporate energy consumption.

Relative Energy Use at the Twenty Largest Energy User Facilities for Rohm and Haas



These chemical monomers form the building blocks for other Rohm & Haas products, so the energy efficiency at the Deer Park plant translates across the entire supply chain, from chemical feedstock to consumer end-products.

The plant consists of eleven different production areas that operate as individual production facilities or "Plants Within A Plant" (PWP). Many of these processes are highly exothermic, and thus, much of Deer Park's steam production results from "waste" heat sources. There are five steam use levels at the Deer Park Plant - 600, 150, 75, 35, & 15 psi. Out of approximately 1,000,000 lbs/hr of the 600 psi steam load, the boiler house only produces on average approximately 200,000 lbs/hr. All of the 150 psi and lower pressure steam is produced by waste heat boilers, backpressure turbines, and let down stations. Much of the energy efficiency gains since 1997 have been achieved by capitalizing on the optimization of cross process and overall plant utility integration – an overall plant systems approach between PWPs. Efficiency gains here also resulted from taking advantage of the plant's large amount of by-product energy production. The PWPs are each independent with respect to production demands, and yet, have a high degree of utility interdependence. Thus, a major challenge was to better integrate this highly complex facility to a new level of energy optimization.

Energy Efficiency - A Spotty History

In the first fifty years of its operation, the plant saw a varying and inconsistent degree of emphasis on energy efficiency. Most previous energy efficiency efforts were individual specialists focusing on specific issues.

The current program really began in 1997, with the formation of a plant-wide energy team. This energy team sponsored an independent plant-wide energy survey and pinch analysis. They then created a disciplined database of energy efficiency improvement opportunities. They subsequently implemented a plant-wide energy monitoring and optimization system based on the software package "Visual Mesa."

The Cross-Functional Energy Team

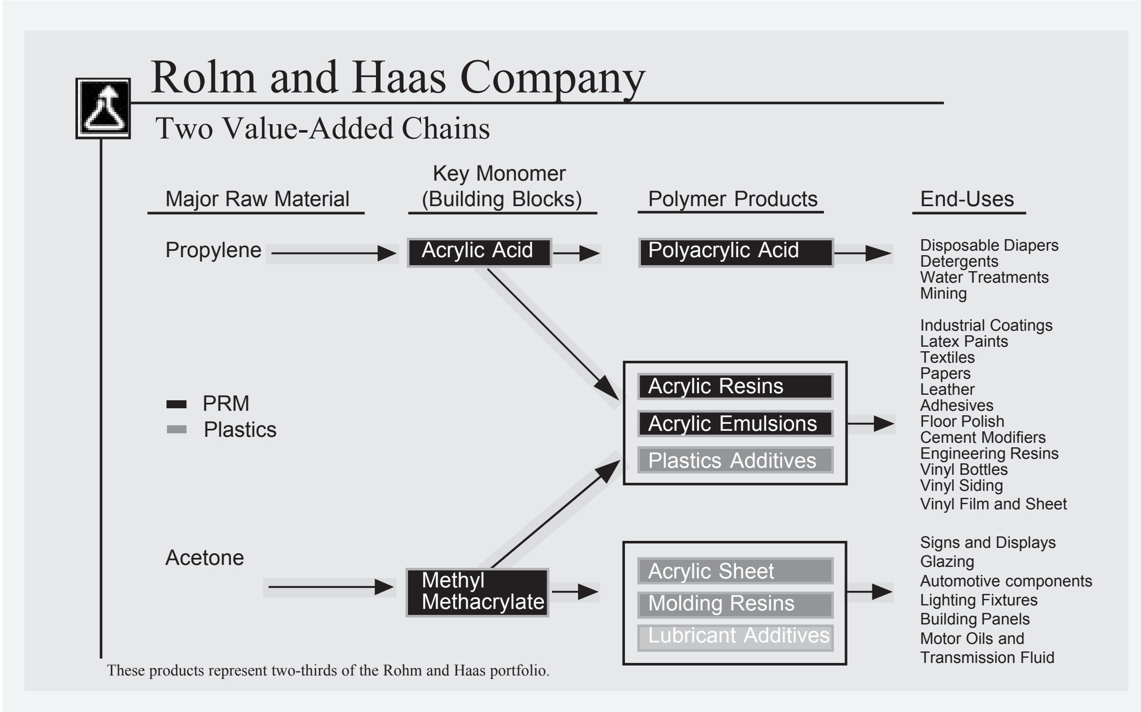
Key to the Deer Park plant's success in energy efficiency was the plant's willingness to work as a team within the many business units in the plant. The cross-functional energy team was started with dedicated resources consisting of PWP production membership, various plant and corporate engineering functions (utility, power, project, electrical), the plant energy manager, and others. The energy team had strong support from the plant manager. The energy team used several tactics to assure a successful program, including:

- A well-defined mission and energy management strategy that aimed to deliver the lowest total long-term production cost.
- Establishment of energy program critical success factors.
- A willingness to reach out beyond the plant's borders to understand the best practices in energy efficiency by attending energy seminars, conferences, networking with companies, energy agencies, etc. The outside knowledge acquired was married with decades of "lessons-learned" at the Deer Park facility to develop a comprehensive inventory of potential resources and opportunities.
- A dual timeline approach to select potential projects for implementation. A short-term tactical plan was used to identify and implement stand-alone projects to quickly deliver on reduced energy and utility costs. A mix of longer term, strategic projects were implemented to ensure the development of systems and infrastructure to deliver sustainable energy savings in the future.

Actions Taken

The team's early emphasis was to identify and champion implementation of all justifiable projects that would increase overall site energy and utility efficiency. Primary goals focused on early cost reductions (1998-2000) to help the plant meet short-term business budget requirements. Key features of the actions taken were:

- Opportunities identified were at both the utility and process area level.
- Communicating metrics to track progress towards goals to management/operational staff.
- Reporting progress to energy stakeholders to assure program deliverables are aligned with business requirements and program gaps (funding, resources, etc.) are resolved.



- Staying on track-decreasing budgeted energy usages to reflect forecasted commitments.
- Developing a sufficient knowledge of plant utility systems to enable proper technical and financial analysis of energy opportunities.
- Recommending a plant-wide energy management system that provides real time energy cost information and optimization recommendations (i.e., operations staff will be more aware of the energy cost implications when making process operation changes).
- Shift plant utility cost system so that each business unit pays for actual usage.

To date the team has identified over 125 projects and more than 40 percent have been implemented over the last 3 years. Roughly 20 percent are still under evaluation, with the remaining percentage not currently justifiable. Examples of the actions taken to achieve energy savings, include: internal energy audit (1995), compressed air leak audit (1998, Petro Chem), fired heater audit (1998, Zink), motor systems assessment (1998, Planergy), plant site energy assessment (1998, Reliant Energy Services), instrument air compressor and dryer audit (1998), building lighting survey (1998, Wholesale Electric), steam system leak and trap assessment (1999, Petro Chem), DOE-OIT "Pumping Systems Assessment Tool" assessment (1999, Oak Ridge National Lab), Pinch Technology assessment (1999, internal staff), infrared thermography audit (1999), real time energy optimizer analyses (2000), second steam system assessment (2000, Armstrong Services), and site assessment (2000, Energy Service Co.).

The Strategic Approach

The Deer Park Plant "Long Term Energy Strategy Document" defines success as being : "when energy management is understood as an implicit part of operational excellence, i.e., it is:

- Understood and actually managed as part of the business.
- Addressed aggressively at the design level.
- Enabled adequately with instrumentation and a management system.
- Instrumented and optimized on a continuous basis by operations.
- A key plank of the Monomers Business Mission.
- Optimized for the whole site.

A sub-team chartered to develop a strategy for the site-wide energy management system found that the needs of the plant could be represented by four key deliverables:

- The real time presentation of strategic energy information including data acquisition, presentation, and metrics.

- A strategic energy-based decision-making tool with a Monte Carlo-(statistical probability) type front end.
- A system for site-wide continuous operational energy optimization.
- A system or tools for local continuous operational optimization.

After considerable investigation, the team concluded that no single tool could provide all four deliverables completely. The team proposed to provide each of the deliverables as follows:

1. The real-time presentation of strategic energy information including data acquisition, presentation, and metrics.

This deliverable includes the field instrumentation, IT infrastructure, and software for data acquisition, data analysis, and data presentation. The data presentation includes displays for operators, unit managers and engineers, plant managers and engineers, as well as metric calculation and tracking.

This system was already partially in place. It was theoretically possible to completely accomplish this deliverable with in-house designed IT infrastructure and software in addition to appropriate field instrumentation. For example, projects to automate the control of the 150 psig and 75 psig steam headers and to provide a tool for steam vent and let down tracking were already underway. There were also plans to provide a means for performance monitoring and performance prediction of key energy equipment. However, it was the opinion of the team that the benefit of performance monitoring, performance prediction of key energy equipment, and identifying all possible metrics would only be realized with a plant-wide system. A plant-wide system could probably be developed in-house, but the team felt that this would not be cost effective. The team also felt that the true benefits of performance monitoring and metrics would only be realized if the system was owned by one person who had the commitment of the area managers to implement the recommendations. Whenever the term performance monitoring is used, it is intended to include both equipment performance monitoring and instrumentation monitoring.

2. A strategic energy based decision making tool with a Monte Carlo type front end.

This deliverable would provide a tool that would allow good business decisions to be made based on current and projected energy usages in the plant. The Deer Park plant is made up of semi-independent production units that share utilities but whose energy and utility usages are strong functions of their own individual business conditions. A plant energy model that accurately shows the current conditions can be used to predict the future minimum usages, the future average usages, and the future maximum usages. Business decisions (for example, the choice between a steam turbine and an electric motor as a driver) based on each of the minimum, average, and maximum cases, may be different for each case. The actual usages in future years would probably be different than any of the aforementioned cases. Thus, in order to make the decision most likely to be the best decision, a Monte Carlo-type analysis allowing for the input of ranges of future energy uses and their probability distributions needs to be performed providing statistical predictions of likely plant energy usages.

The resident utility process expert had developed an excellent spreadsheet model of the plant steam system that was very nearly complete. One solution would be to continue work to finish this model and to incorporate a Monte Carlo-type front end such as “@Risk” or “Crystal Ball”. However, this would require a significant amount of time and would delay the development of other energy-saving projects. Another option would be to ask the supplier of the plant-wide energy management system (for example, Visual Mesa) to incorporate an Excel-based input tool that could then use “Crystal Ball” or “@Risk” to drive the Monte Carlo analysis. Because “VisualMesa” was ultimately chosen as the means to provide the other deliverables, the latter option was chosen to provide this deliverable.

3. A system for site-wide continuous operational energy optimization.

This system includes taking the data from the first deliverable (real-time presentation of strategic information) and incorporating it into a plant-wide optimizer program. The ultimate goal would be to make as much of this optimization as possible closed-loop, but the initial phase would probably be advisory only. If an optimization program was selected, it would also facilitate the first two deliverables.

After looking at many different software platforms and programs, the team chose the VisualMesa program offered by Nelson and Roseme. The site-wide system includes all steam, all fuels including waste fuels, and condensate. It provides real-time optimization, providing new energy-saving opportunities. The team is currently building a Monte-Carlo-type front-end to facilitate "what-if" studies.

4. ***A system or tools for local continuous operational optimization.***

The VisualMesa based optimization program allows for some local continuous operational optimization. There was also an alliance announced separately to use AspenTech's suite of process optimization tools at this site. The team decided to handle local optimization on a case-by-case basis. The team still strongly believes that there is much benefit to be had from local continuous operational optimization, especially if that optimization can be made to be closed loop.

Critical Success Factors

The team then identified nine critical success factors that they believed were imperative if the site -wide strategic energy management system was to succeed:

- An owner/champion must be designated immediately. This person should be responsible for ensuring that the instrumentation, IT infrastructure, and model are kept up to date and are reliably maintained. This person should also be responsible for, and have the authority to, ensure that the units are held accountable for their energy use.
- Businesses must be held accountable for energy used per pound of product and other energy metrics.
- A cultural change is needed that will allow the implementation of energy optimization. For example, a true paradigm shift on operating philosophy for controlling 150#/75# letdowns and vents.
- The Energy Management System must be used in order to obtain benefits.
- The instrumentation must be reliably maintained. The readings must be believable.
- Resources must be made available to implement identified operational improvements.
- Performance must be monitored and indicated deviations from target acted upon in a timely manner.
- Adequate training must be provided.
- The Energy Management System must show where operational improvements can be made relatively quickly.

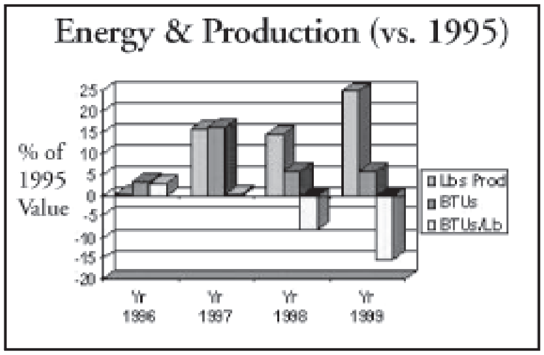
The Results

The highlights of the energy efficiency achievements since 1996 at the Rohm and Haas, Deer Park, Texas, facility are:

- A 17 percent energy reduction on a per pound of chemical production basis-see graph above. Since 1997, absolute energy consumption has decreased 10 percent even though production went up by 7.7 percent.
- The Deer Park plant's energy savings achievements have already exceeded a 2005 Rohm and Haas corporate goal to reduce energy consumption by 15 percent (per pound basis) from 1995 levels.
- Current annual energy savings (from 1996 to 1999) are at least 3.25 trillion Btu per year, valued conservatively at $15 million dollars per year (both supply and demand charges). This amount of energy savings is equivalent to the energy consumption of 32,000 typical U.S. homes. (101 million Btu per housing unit; EIA data)

Annual emission reductions are as follows:

- **NO_x = 800 tons per year.**
  (assuming 0.5 lbs. NO_x emissions avoided per million Btu saved)
- **CO_2 = 51,350 tons per year, equivalent to removing 25,000 cars from the roads.**
  (31.6 lbs. CO_2 emissions avoided (carbon equivalent) per MMBtu natural gas saved, and a typical car emits 2 tons of CO_2 per year)



The Path Forward

The ultimate goal of the Deer Park energy program is to achieve the lowest total operating cost year in and year out. This is verified in real-time and on a long-term basis. Future energy program enabler opportunities will include:

- Increased use of energy usage and cost performance metrics for day-to-day operations.
- Increased day-to-day use of the real time plant-wide energy management system.
- Utilization of Energy Service Company partnerships for new opportunities.
- Continued facilitation of a plant culture where energy awareness is well understood and practiced at both plant operating and engineering design levels.
- Increased use of advanced process control.
- Increased automation of optimization.
- Increased use of metrics and accountability.
- Extension to water and other sustainability resources.
- Extension to other plants/replication across corporation.

Acknowledgments

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For more information contact:

Fred Fendt
Rohm & Haas Company
Email: ffendt@rohmhaas.com
Phone: (215) 785-7661

Celanese Chemicals Clear Lake Plant Energy Projects Assessment and Implementation

Joel Weber, (formerly with) Celanese Chemicals

Abstract

The Clear Lake Plant of Celanese Chemicals has implemented a strategy to reduce energy consumption. The plant identified, designed, and completed several projects to improve its chemical production processes. These projects reduced steam use, fuel gas use, and electricity use. Some involved capital changes, but most used existing assets more efficiently. Celanese now realizes cost savings while operating a more efficient and reliable plant.

Introduction

The Clear Lake Plant pursued a strategy to reduce energy use in two stages. The first stage was a part of its Low Cost Producer program. The plant conducted a series of brainstorming meetings to generate ideas to reduce production costs, including energy costs. Teams of engineers and specialists reviewed the ideas to refine them into potential projects.

The second stage of the strategy was to construct a predictive model of the plant's steam and energy transfer systems. The purpose of this was to reduce or avoid inefficiencies resulting from breaking down high pressure steam over valves, venting steam, and losing water. The model considers fuel gas and electrical usage and billing rates from suppliers. The model anticipates the effect of a proposed change in one area, on the overall energy balance of the plant. From the potential projects proposed in the first stage, the predictive model helped to select the most beneficial ones to pursue.

The Clear Lake Plant expects reduced energy use (adjusting for plant expansion projects), especially in steam and fuel gas. Preliminary data from 1999 over 1998 shows improvement, most of which can be attributed to several projects. Most projects involved no capital expenditure; some took advantage of existing equipment or scheduled equipment replacements to design a more energy-efficient system.

Examples of Completed Projects

Heat Exchanger

One of the plant's processes includes a byproduct removal system, consisting of an absorber tower and a stripper tower, with a process-to-process exchanger between two of the streams. Over the years, the interchanger performance had deteriorated slowly, due to fouling and corrosion. Process modeling showed that about 50Mlb/hr of steam driving the stripper reboiler could be reduced by replacing the old exchanger. The unit replaced the exchanger with one similar in size, with new cleaning nozzles and redesigned baffles. The project reduced low-pressure steam used in the stripper, amounting to 2.5 percent of the plant energy load.

Use Excess Process Steam for Heat Recovery

Another process generated steam containing a small amount of process material. This could not go directly into the plant steam system, so the excess steam was vented. In a separate process, purchased steam heated a Flasher vessel. To improve this situation, the unit implemented a low-cost project to add piping. The process steam was lined up to the Flasher reboiler, which recovered the heat and condensed the steam. The resulting condensate went to wastewater treatment. This displaced purchased steam from the reboiler, saving at least 0.5 percent of the plant steam load.

Use a Single Incinerator Instead of Two

In one process, two incinerators were operated for liquid and vent wastes. The second backed up the first incinerator, burning fuel gas for warm standby. This avoided having to trip out the process reactors in the case that the first incinerator tripped out, affecting reliability and lost production time. A study found that trip-outs of the incinerator were less frequent than expected. Therefore, it was more economical to use only one incinerator. Eliminating the hot standby resulted in large fuel gas savings of $1 million per year.

Run a Distillation Tower Only Part-Time

A plant process had a distillation tower to recover a byproduct from a product stream. Previously, it had run all the time, but at fairly low rates. Now the unit manages the inventory so that the tower operates only part of the time, for 10 to 15 days per month. For the other 15 to 20 days per month, the tower shuts down. This saves on reboiler steam, cooling water, and some electricity savings.

Redesign of Exchangers

Another process has exchangers to recover excess heat from a vapor phase reaction product stream. The exchangers consist of a large helical tube inside a shell, with the process material on the tube side and the boiler feed water heating to steam on the shell side. For this project, the exchangers were redesigned to give more heat transfer overall. Therefore, the plant recovers more byproduct steam. This is an example of a project which started as a debottlenecking project, but also recovers energy.

Optimize Tower Operation

There are several projects under way to optimize the operation of distillation towers. Using one tower project as an example, operations decreased reflux, changed tray temperatures and tower pressures, and decreased reboiler steam. Although the savings can vary with rate changes in the process, this project alone can save 0.4 percent of the plant steam load.

Improve Process Control of Large Air Compressor

Engineers improved process control for a large air compressor which feeds a reaction train. To improve efficiency, the new control strategy minimized the differential pressure across the flow control valve downstream of the compressor. In order to open up the flow control valve more, the air discharge pressure of the compressor was reduced by lowering the speed of the compressor. This resulted in saving the high-pressure steam which powered the compressor.

Eliminate Hot Standby for Utilities Boilers

Previously, two boilers ran and a third was on standby. The third burned fuel gas to keep the tubes warm, in case the other boilers tripped. Later a study determined that the reliability of the other boilers was good enough to run without a spare, so the standby was then eliminated. This saves about $640,000 per year on fuel gas, 2 percent of the plant's energy budget.

Implement a Range of Smaller Projects

The plant also implemented several smaller energy-saving projects. Eliminating hot standby for spare turbines, shutting down outmoded process systems, and optimizing pump impeller usage are some examples. Other projects made better use of steam by adding lines to transfer it where it was needed. The plant changed tower operation to use lower-pressure steam when possible. On a continual basis, the plant makes choices to operate equipment with turbines or with motors.

Conclusion

The Clear Lake Plant has achieved reductions in energy usage by selecting and implementing projects which required little capital expenditure. These changes are expected to improve overall energy productivity. Often energy reductions occur hand-in-hand with efficiency, productivity, and reliability improvements.

Savings in Steam Systems (A Case Study)

Rich DeBat, Armstrong Service, Inc.

Abstract

Armstrong Service Inc. (ASI) conducted an engineered evaluation at an ammonium nitrate manufacturing facility during the fall of 1999. This plant manufactures nitric acid and high and low density ammonia nitrate. The purpose of this evaluation is to identify energy losses and system improvements in the steam and condensate systems. Steam system improvements focus on lowering the cost of steam, wherever possible, with paybacks of three years or less.

Overall, this ASI evaluation identifies six (6) steam savings proposals with an average simple payback of 2.9 years.

This evaluation also identifies one system deficiency that will lead to unnecessary expenditures if allowed to continue, but would help to increase production if the suggested improvement was implemented.

The following report details the individual findings and outlines the corrections needed. The savings generated from these improvements will more than pay for themselves in short order.

Table 1. 400 psig Steam Production Costs

Total steam cost	$1,426,325/yr.
Average steam output	40,0000 #/hr.
Steam cost less sewer and electric	$5.94/1000 lb.
Natural gas cost	$3.25/MCF
Average boiler efficiency	54.0%
Average heat cost for boilers	$5.56/10^6 BTU
Water cost	$1.10/1000 gals.
Annual chemical cost	$0.10/1000 gals.
Average treated water cost	$1.20/1000 gals.
Make-up boiler feedwater	22,800 #/hr.
Average condensate temperature	200 deg F
Average condensate cost	$0.92/1000 lbs.
Average sewage cost	$0.00/1000 gals.
Average electricity cost	$0.042 per kWh

Site Observations

Steam Generation

The plant has the ability to generate steam from a number of sources. Typically, the steam requirements for the nitric acid plant and most of the high or low density plants are met with the steam generated from the waste heat boilers in the nitric acid production process. The three waste heat boilers are rated at 600 psig, 100 psig and 40 psig. In addition, an indeck gas fired boiler rated at 80,000 #/hr and 400 psig is used to supply supplemental steam. Table 1 details related costs for steam production in the 400 psig boiler.

A Kenawee Boiler rated at 14,000 #/hr and 150 psig is used as an emergency standby boiler.

Steam Distribution

Steam is distributed throughout the nitric acid plant to the various steam users. From the nitric acid plant two separate outdoor steam mains (150 and 220 psig) run approximately 1/4 of a mile to the high and low density production plants. A branch line from the high density area supplies steam to the valley area.

Steam Utilization

In the nitric acid plant 600 psig steam is used in the ammonia burning process and the steam superheater on the extraction/reheat loop of the steam turbine. The 600 psig steam is also reduced to 220 psig through the steam-driven turbine air compressor. This steam is used in the ammonia superheater and the tailgas heater. The 220 psig steam can also be reduced to 100 psig and 25 psig through reducing stations, if needed. The 100 and 40 psig steam is mainly used for tracing in the nitric acid area.

The excess 220 psig steam from the nitric acid plant is exported to the high density area and valley areas. It can also be reduced to 150 psig and exported to the low density area. The steam requirements in the valley, low density and high density areas are greater than the steam exported from the nitric acid plant. Steam from the gas-fired indeck boiler is also reduced and supplied to these areas, as required. See Figure 1 for a steam flow diagram. The main steam users in the high density plant are the evaporator, ammonia superheater, and the ammonia vaporizer. Other users are cooler heating coils and the granulator air heating coils.

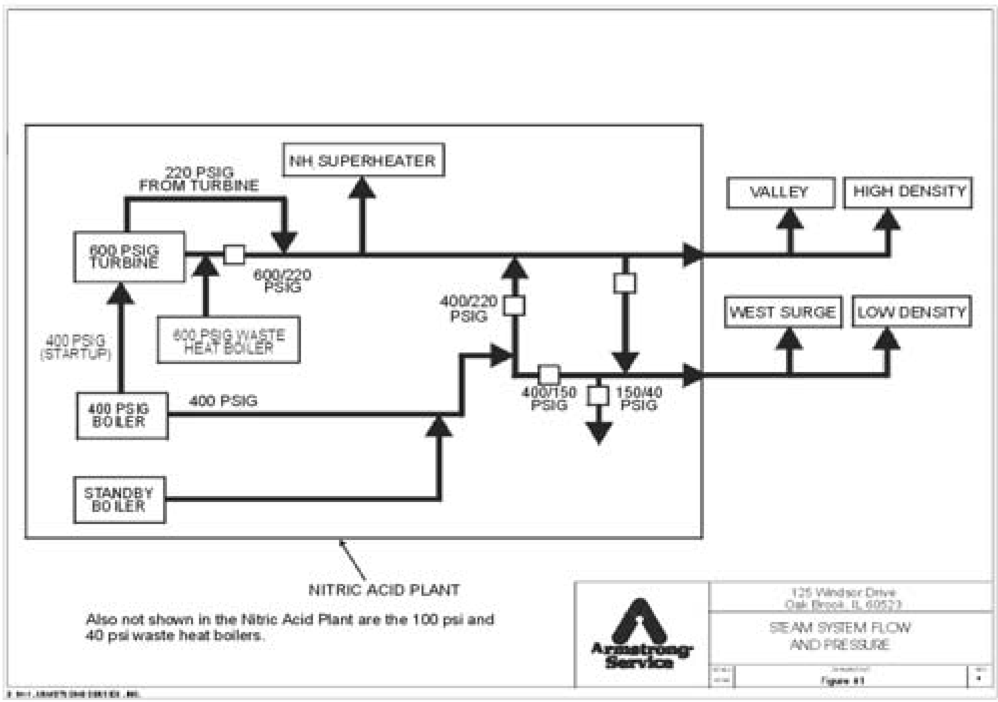
The main users in the low-density area are the ammonia vaporizer and ammonia superheater. Steam is also used in the air-heating coils for the drum dryers.

Steam System Savings Proposal #1: Repair Steam Leaks

Background

In the nitric plant area a large number of steam leaks and valves were discovered open to atmosphere (see Table 2 for details). The steam leakage rate will increase during the winter months as steam

Figure 1. Steam Flow Diagram



Condensate Return

In the nitric acid plant, condensate is returned to a vented receiver/ electric pump set and pumped back to a main storage tank. A pressure-powered pump is used to return condensate from the valley area to a main return line. A vented receiver with electric pumps is used to return condensate from the high density area to the same main return line. The low density and west surge tank area also return condensate to the above main return although there are no condensate pumps in these areas. The main return line from the valley, low density, high density and west surge area returns the condensate to the main storage tank. Condensate is pumped from the main storage tank to the deaerator, as required.

tracing is turned on and more valves are opened to the atmosphere. There are also several boiler feedwater leaks and additional steam leaks in the high and low density plant areas that are not noted here.

Discussion

Unnecessary steam discharge will drive up the cost of steam. Boiler fuel usage will increase, as more fuel must be used to supply the additional steam load. The steam lost to atmosphere increases the make-up water requirements, as it is not recovered as condensate. The additional makeup water also needs more added heat and water treatment/ chemicals when compared to returned condensate.

Table 2. Identified Steam Leaks

Steam Leakage Rate to Atmosphere (Napiers)				
Orifice Size	Inlet Pressure	#/hr	Location	Action
0.047	400	37	Relief valve on 400 psi boiler outlet header	Repair relief valve
0.047	400	37	Control valve vent on 400 psi outlet header	Replace control valve
0.094	400	147	Flange on venting control valve	Replace gaskets, repair or replace flanges
0.094	400	147	Valve packing on bypass control valve	Repair leak/replace packing
0.047	400	37	Isolation valve on abandoned steam header	Replace valve
0.094	400	147	Valve packing on branch line to PRV station	Repair leak/replace packing
0.016	400	4	Main steam line after 400 psi boiler	Repair leak
0.063	220	37	Relief valve on 220 psi steam main	Repair relief valve
0.063	220	37	Valve packing leak on 220 main line	Repair leak/replace packing
0.063	150	26	150 psi reducing station	Repair leak
0.063	140	24	Steam supply to air tank tracing	Install steam trap
0.141	125	112	Relief valve on 100 psi boiler accumulator	Repair/replace relief valve
0.094	40	19	Tracing blow down valve	Replace valve
0.094	40	19	Tracing on 600 psi control valve	Repair leak
0.109	40	26	Tracing steam for caustic soda tank pumps	Install steam trap
0.094	40	19	Tracing steam	Repair leak
0.125	40	35	Union on drip station ahead of 40 psi PRV	Replace union
0.125	15	19	Valve cracked open on takeoff line ahead of caustic tank	Install steam trap
0.125	15	19	Valves open to atmosphere on end of branch line in water treatment area	Install steam trap
0.125	15	19	Tracing line leak near cooling tower	Repair leak
0.19	15	42	Valve packing on control valve to deaerator (inlet valve)	Repair leak/replace packing
0.06	11	4	Valve packing on control valve to deaerator (outlet valve)	Repair leak/replace packing
0.13	15	19	Tracing line leak near waste heat boiler accumulator	Repair leak
	Total #/Hour	1,033		

As can be seen in Table 2, a number of "small" leaks can add up to a large annual cost, so it is imperative that all steam leaks be repaired as quickly as possible. If the leak is ignored, the steam loss will increase over time, as will the cost of repairs.

Recommendations

Repair steam leaks as identified in Table 2, especially the high-pressure ones, and install steam traps in lieu of partially open valves.

Estimated Savings

The estimated annual cost savings for repair of steam leaks in the nitric acid plant, and installation of steam traps where needed, is $53,000/year.

Costs

The expected payback period is 1.5 years.

Steam System Savings Proposal #2: Correct Trapping on High Density Evaporator

Background

The condensate drainage method from the evaporator in the high-density area has been changed from the original design. The evaporator originally had a condensate pot with a liquid level control on its outlet to meter condensate flow. This was in essence an expensive electronic steam trap. The liquid level controller and control valve have been removed and a gate valve is now installed in place of the control valve. The gate valve is manually set to control condensate flow. The condensate from the evaporator is discharged to a pressurized flash tank (100 psig) and is then piped to an atmospheric receiver where it is pumped into the condensate return line to the nitric plant. The steam plume off the atmosphere receiver's vent is substantial. See Figure 2 (on page 52) for the current piping arrangement.

Discussion

Using a gate valve to control condensate flow from the evaporator's coil can cause a number of problems. Unlike a properly functioning steam trap (electronic or mechanical), the gate valve cannot modulate its discharge orifice size in response to condensate load variations. If the gate valve is not open enough, condensate will back up into the evaporator coil when the load increases. This means poor equipment performance and possible damage due to water hammer. The obvious solution is to make sure the valve is always open far enough to pass even the highest condensate loads. However, when the condensate load is less than the peak value, the valve will allow live steam, as well as condensate, to pass through it. While this live steam flow may not adversely affect the coil's operation, unless it is a very high amount, it does make the overall steam system very inefficient. Higher steam flow leads to increased pressure drop (loss of energy), and the potential for erosion and water hammer in the steam distribution piping is increased. Excessive steam flow to the condensate system will increase the back pressure to all other steam users that return condensate and also may lead to water hammer, as is the case here.

The evaporator drainage system was also originally designed to make use of the 100 psig flash steam generated from the 220 psig condensate. The 100 psig flash tank is still in place, but the original user (HVAC coils in the air handler in the truck loading offices) has been removed. Excessive live and flash steam from the evaporator will quickly elevate the pressure in the 100 psig flash tank to the evaporator's steam supply pressure (220 psig). To prevent this, the bypass valve around the 100 psig flash tank is open and venting this steam to the condensate line that runs from the 100 psig tank to the atmospheric tank. As a result, a very large amount of steam is being vented from the atmospheric tank and water hammer and erosion is prevalent in the system.

Recommendation

The first priority is to eliminate the excessive amount of steam being vented from the atmospheric tank by installing a properly sized steam trap in place of the gate valve that is currently being used to control flow. The bypass valve on the 100 psig flash tank also needs to be replaced as it more than likely has been damaged by steam flow through it while in the partially open position. See Figure 3 (on page 52) for the proposed piping modifications.

To further optimize the system, the 100 psig flash steam from the flash tank must be utilized. Based on the design steam load for the evaporator of 13,724 #/hr, the flash steam produced from the 220 to 100 psig reduction would be 769 #/hr. If this steam and condensate is further reduced to 0 psig, the total amount of steam being vented would be 2,312 #/hr. If the 769 #/hr of 100 psig steam is reused, the amount of vented steam at 0 psig will be reduced to 1,440 #/hr. Two possible uses for the 100 psi flash steam are steam coils for the air heater or the cooler heating coils.

Estimated Benefits

Estimating an excessive steam usage of 2 percent, due to the use of the gate valve as a steam trap, gives an annual dollar loss of $13,700/year. In addition, recovering the 100-psig flash steam for use in the air heater equates to an annual cost savings of $38,300/year. The total annual cost savings would be $56,000/year.

Costs

The expected payback is 2.8 years.

Steam System Savings Proposal #3: Improve Condensate Return from Low Density Plant

Background

There are two main steam supply lines to the high and low density and valley areas and both lines are 6" diameter pipe. There is one main condensate return line to the nitric acid plant and this line is 4" pipe. The high density and valley areas both have condensate pumps to return condensate to the main return line. However, there are no condensate pumps in the low density area other than the small pumps for the large storage tank on the hill. The combination of pumped condensate from the high density and valley areas and biphase condensate from the low density area is causing severe water hammer in the condensate return line. In addition, condensate from the large storage tank, and other steam users in the low density plant, can not be returned due to high back pressure in the return line. Currently, this condensate is drained to the ground.

Discussion

The lack of condensate pumps in the low density plant means that the condensate flow from this area is biphase. In other words, there is both flash steam and condensate in this return line. In a biphase condensate system, the condensate typically flows due to the gravity pitch of the line, and flash steam flows as a separate phase over the top of the condensate due to the steam pressure drop. This arrangement works best if there is a head pressure difference (gravity) in between the equipment and the final drainage point and the final drainage point is at zero or very little pressure. If a piping elevation rise or back pressure exists in the line, the condensate must collect in the pipe to the point

Figure 2. Current High Density Evaporator Piping

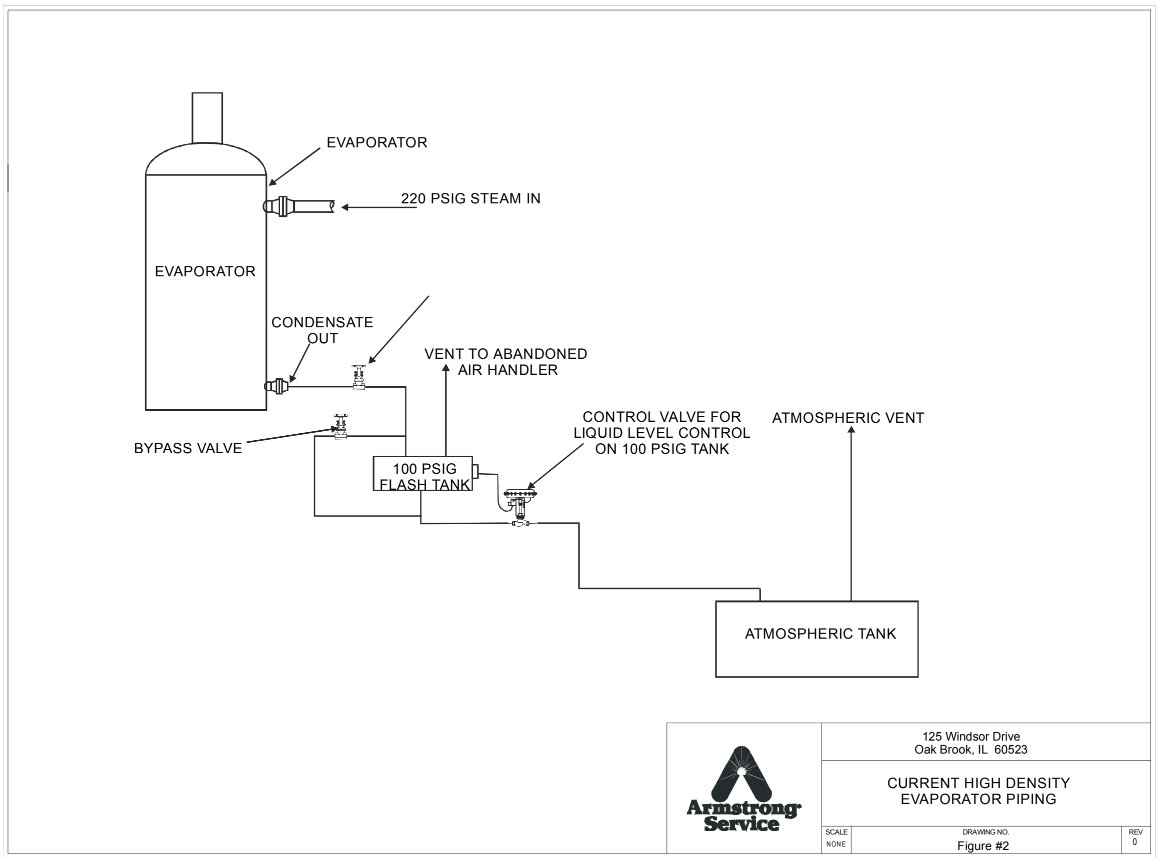
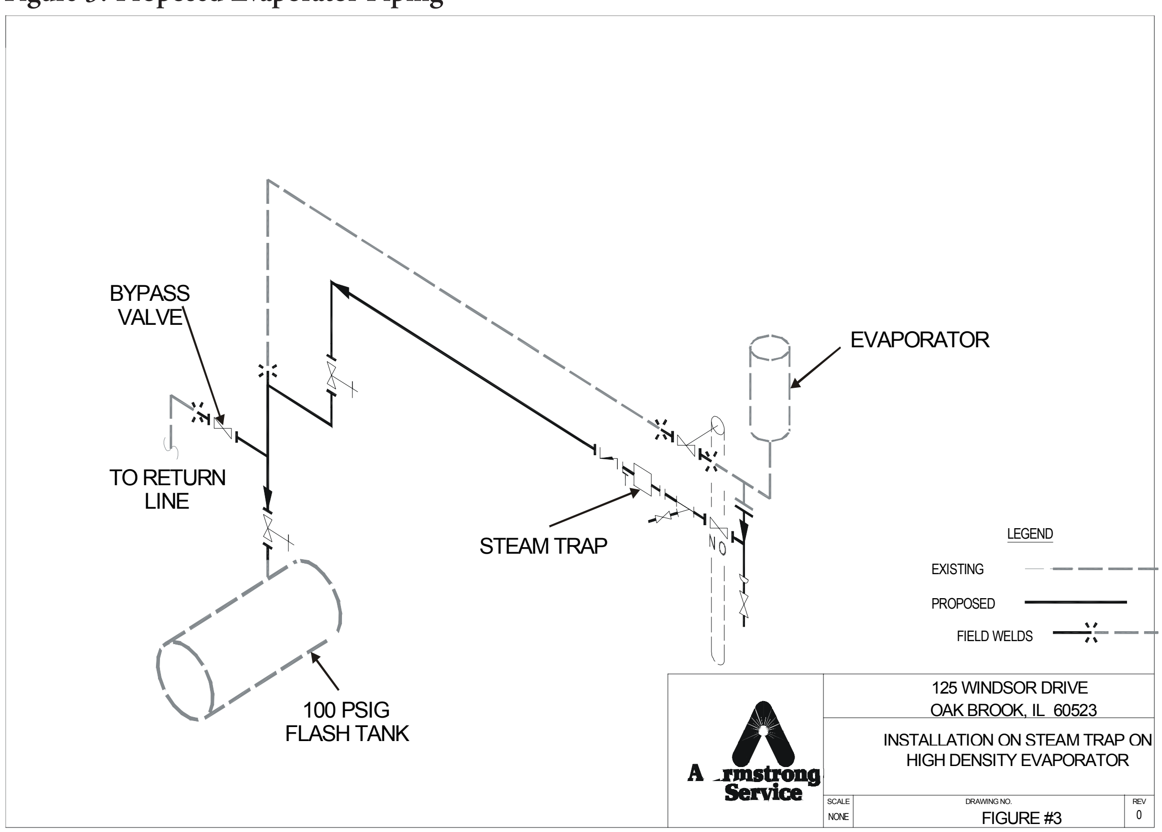


Figure 3. Proposed Evaporator Piping



where it seals the pipe off. Then the flash steam will build until there is enough pressure to push the condensate. The resultant slugs of condensate will move very fast (up to 90 MPH) and slam into any elbows, tees or fittings. This is called "differential" water hammer. Additional water hammer will occur when the flash steam from the biphase flow is introduced into the pumped condensate line. The flash steam will instantly condense in the cooler condensate creating an implosion/explosion reaction. This is called "thermal" water hammer. In addition to the water hammer, back pressure in the return line will be present at the steam traps that are not isolated from the line by a receiver/pump combination. This back pressure will prevent proper condensate drainage on the steam-using equipment.

Recommendation

When condensate cannot flow by gravity to the final drainage point or high backpressure exists in the return line, a pump must be used to give the condensate the motive force it requires. In this case, a pump and receiver package should be placed in the low density plant to collect condensate and pump it back to the nitric acid plant.

Estimated Benefits

The estimated cost savings available by returning condensate that is currently being drained in the low density area is $17,000/year. Additional benefits will be realized in overall system operation, safety, and equipment life.

Costs

The estimated payback is 3.8 years.

Steam System Savings Proposal #4: Recover Waste Heat in Boiler Blowdown Water and Flash Steam

Background

Blowdown water from the high-pressure (600-psig) waste heat boiler in the nitric acid plant is piped to a 20 psig flash tank. This allows a small percentage (22 percent) of the hot condensate to "flash" into the low pressure (20 psig) steam line. The condensate is sent to an atmospheric flash tank where additional flash steam (4 percent) is released into the air and the remaining condensate is discharged directly to the sewer. Also, in the nitric acid plant area, condensate from the high pressure and medium pressure (220 psig) users is piped to a different 20 psig flash tank and, again, this flash steam is piped to the low pressure steam line. The condensate from this 20 psig flash tank, along with condensate from the low pressure steam users and the turbine's surface condenser, is piped to a large atmospheric tank. The flash steam from this tank is vented to the air and the condensate is pumped back to the deaerator tank.

Discussion

Valuable heat in the high-pressure boiler blowdown water and in the flash steam from the large atmospheric tank vent is being lost to the surroundings. This heat can be recovered by using it to preheat deionized makeup water to the deaerator.

Recommendation

A deionized water supply line is already in place to the high-pressure boiler area. A stainless steel shell and tube heat exchanger, that was previously used to preheat ammonia, has been abandoned in place. This heat exchanger can be relocated and used to transfer the heat in the high-pressure boiler blowdown water to the deionized water. The preheated makeup water can then be sprayed into the vent line on the large atmospheric tank, which will condense the flash steam that is currently being vented. This will reclaim the heat and the water that would otherwise be lost to the air as steam. See Figure 4 for proposed arrangement.

Estimated Savings

The estimated cost savings for this proposal is $16,445/year.

Costs

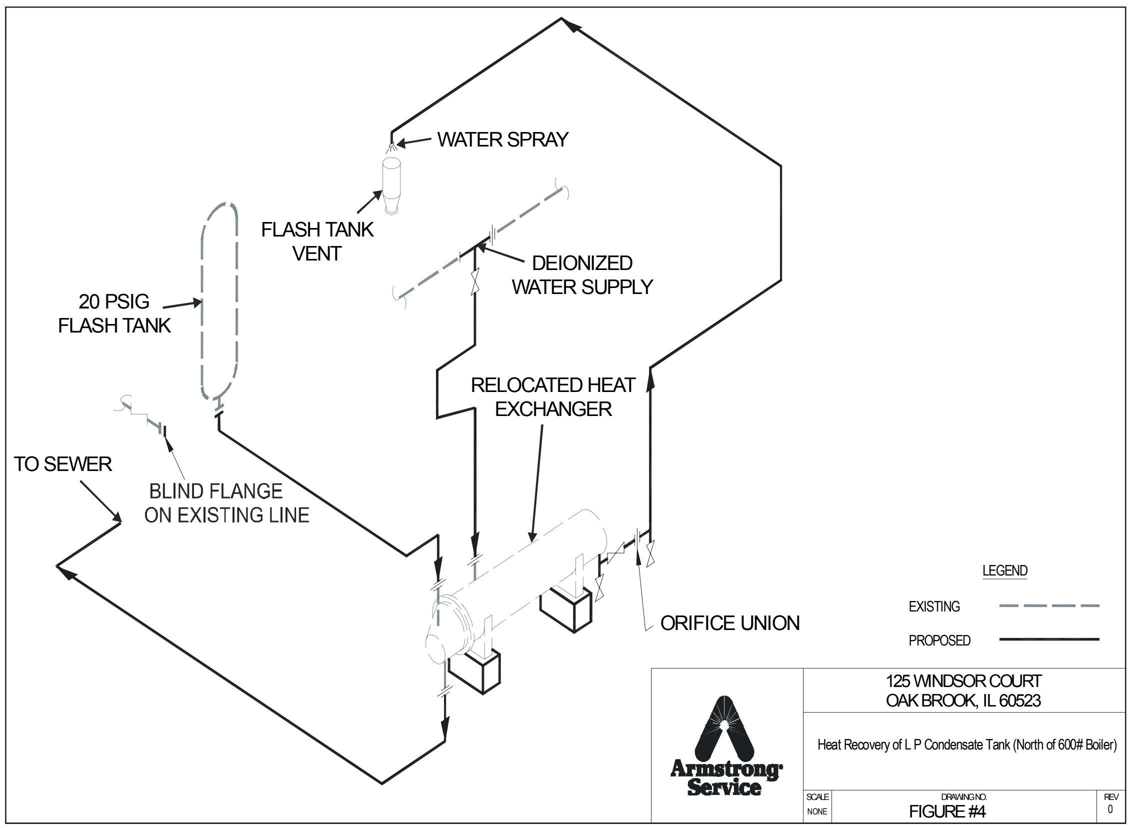
The estimated payback is 6.5 years.

Steam System Savings Proposal #5: Steam Trap Repair and Replacement

Background

There are approximately 210 steam traps at this facility. A steam trap survey was completed in January of 1999. Of the 170 tested steam traps in service, 62 had failed; this equates to a 36 percent failure rate. Based on information from the plant,

Figure 4. Proposed Piping for Boiler Blowdown Heat Recovery



it is assumed the failure rate of 36 percent has decreased, through ongoing maintenance, to 14 percent, resulting in an adjusted annual steam loss of 14 million pounds. Using a steam cost of $5.97 per thousand pounds and an operational time of 6800 hours/year, the annual dollar loss (monetary losses) is estimated at $100,000.

Discussion

The energy efficiency of a steam distribution and condensate return system is strongly dependent on the effective usage of steam traps. The basic function of a steam trap is to prevent live steam from blowing through and to allow condensate that is formed, due to heat being released in the system, to be drained. Efficient removal of condensate is necessary to avoid backup of condensate in the system. Condensate backup deteriorates the heat-transfer process efficiency, causes corrosion, and may lead to severe damage caused by water hammer in steam distribution lines, valves and equipment. The second function of a steam trap is to facilitate the removal of air from the steam distribution system. Air is present in the system during start-up, and is introduced with the makeup water and through vacuum breakers. The presence of air in the system deteriorates heat transfer efficiency by insulating the heat transfer surface and causing corrosion when it is absorbed by the condensate.

To provide long-term and energy-efficient performance of steam traps, the priority aim is to establish an adequate maintenance system. Once all the changes and recommendations have been implemented, the following preventive maintenance guidelines should be used.

In general, all steam traps should be tested at least twice each year - once in the fall and once in the middle of the winter. The recommended test method should be a combination of visual, sonic, and temperature methods. See the following table for more specific testing frequency guidelines. Keep a good record of the updated information. A steam trap computer database program is the best way to store and maintain these records. The database can also be used to store piping drawings

Table 3. Trap Testing Frequency

Operation Pressure (psig)	Application			
	Drip	Tracer	Coil	Process
0-100	1	1	2	3
101-250	2	2	2	3
251-450	2	2	3	4
451 and above	3	3	4	12

of each trap application and prior history or problems with the traps. It should be used to print out all traps by the areas that need to be tested. Each trap, as it is tested, can now be checked off. Any changes that have been made to the tag number should be "written over" the old entry on the computer printout. This becomes the input to the computer.

As each trap is tested, all strainers should be blown down for a couple of minutes to ensure they are clean. Each isolation and bypass valve should be closed and ultrasonically checked for leakage.

Every trap, valve, or strainer that has failed should be tagged for replacement or repair.

A well-run steam trap management program will:

- Reduce operating costs.
- Improve safety.
- Increase production or service.
- Reduce maintenance and other costs by eliminating condensate return problems, freeze-ups, water hammer and corrosion.

In summary, using failed steam traps or not using any, leads to three ways of waste:

- Waste of live steam through the failed trap.
- Disturbing the local condensate return system. The high back-pressure in the condensate return lines decreases the pressure differential across the other traps, thus decreasing their discharging capacity.
- Deviation from the required outlet temperatures of the heated fluid could lead to product material disturbances or more heat input.

Recommendation

It is recommended to replace all the identified defective and misapplied steam traps. Plants should also institutionalize a steam trap maintenance program by replacing steam traps with statistical projected failure during the maintenance contract period in order to supply better quality of steam and to achieve better performance of steam-using equipment.

Estimated Benefits

An estimated annual cost savings for replacing all identified defective steam traps and institutionalizing a steam trap maintenance program is $100,000.

Cost

The estimated payback period is 2.4 years.

Steam System Savings Proposal #6: Boiler Optimization

Background

During the plant-wide steam system site evaluation, ASI engineers were able to test, visually inspect and observe the operation of both the Indeck and Kewanee boilers. As a result of this evaluation process, the Indeck boiler was found to have the highest potential for significant energy savings. Therefore, this steam system savings proposal will address the improvements with the greatest impact toward increasing energy efficiency which involve upgrading and replacing controls, transmitters and loops, and boiler and burner boiler casing.

Discussion

A distributed control system (DCS) is designed to take control of the process or the plant. In the power industry, the term distributed control system (DCS) is generally applied to the system that implements boiler control and data acquisition functions of the power plant.

A state-of-the-art DCS is typically composed of modularized microprocessor-based processing units, input modules, output modules, operator workstations, engineering workstations, printers and other types of peripheral devices, all connected through a multiple-level communications network. DCS manufacturers have standard modules for different functions. They generally fall into two categories: control modules and data processing modules.

The control modules are structured to perform a variety of control and computing tasks, such as PID (proportional plus integral plus derivative) control, binary logic, and arithmetic functions. Some manufacturers have separate modules for modulating and on-off control functions and others have combined the two into one module. For some manufacturers, each module is available in varying sizes to suit a user's needs.

In addition to the control functions, the DCS needs programs to implement all operator interface, report generation, and data storage and retrieval functions. The manufacturers generally divide these functions into separate packages, each with a specially structured program that serves as a platform for the user to develop graphic displays, other forms of data presentations and format operating logs. In general, the programming functions are user-friendly and menu-driven, so that they can be a programming tool that is easily understood by the user's personnel.

Programming functions are conducted from the engineering workstation, usually with a full complement of CRT screen, keyboard, auxiliary memory, and floppy disks. The workstation is normally connected to the DCS communications network, and the programs developed from the workstation can be directly downloaded to the individual processor modules in the system.

A DCS application in a boiler house operation typically covers the following areas:

- Boiler controls, including the combustion (firing rate), furnace draft, steam temperature, and feedwater control loops.
- Burner control.
- Control loops in the plant auxiliary system that need to be monitored and/or controlled from the central control room.
- Alarm annunciation and recording features.
- Monitoring function for other separate stand-alone controllers or control systems.
- Remote indication and recording of plant operating parameters.
- Periodic reports and event logs.
- Historical data storage and retrieval functions.

In nearly all power plants and boiler house operations built in recent years, the monitoring and data processing tasks that the DCS is capable of handling have largely replaced the conventional mimic panels, annunciator light boxes, indicators, and recorders in the plant control rooms. It should also be mentioned that DCS application in plants has been expanding into motor controls for the balance of plant equipment (pumps, fans, etc.), which was once predominantly an area for PLC applications. At the present time, the choice between PLC and DCS for this application is largely a matter of cost and user's preference.

The next area to be discussed is that of burners. Burner designs continue to be developed and are capable of meeting new industrial standards without the use of flue gas recirculation for certain applications. By using a combination of an air-fuel lean premix and staged combustion, peak flame temperatures are reduced without the need for flue gas recirculation. While the staged combustion is a unique burner design, it can be effectively used in today's modern boiler applications. New boilers, as well as older operating boilers requiring retrofitting, will benefit from these successful developments.

Finally, during flue gas testing analysis, our engineers discovered higher than normal oxygen percentages. The location and the cause were confirmed during a later outage. In addition to the casing leak, two locations along the rear side walls and roof areas were found to have broken or missing refractory. The rear wall casing that houses an inspection sight glass port was also found to be deteriorated and was in need of repair.
The problems discovered with regard to broken and missing refractory and the boiler-casing leak do result in heat loss that directly effects the loss of thermal efficiency.

There are three major recommendations proposed for this steam system savings proposal.

Option 1

Recommendation

Repair casing and refractory leaks on existing boiler, tune existing burner system after refractory repair, and continue with normal operation of the existing boiler.

Benefits

The estimated cost savings available by repairing the existing boiler and tuning existing burner system is $64,000. The dollar total is based on a 4.5 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 1 estimated payback is 7.5 months.

Option 2

Recommendation

Evaluate, select and install a distributed control system for a boiler control upgrade. A distributed control system should contain the following minimum requirements:

- Highly reliable system architecture.
- Open architecture programming and communications.
- High accuracy inputs with noise and input spike protection.
- Capable of complete power supply, processor and/or I/O redundancy.
- Hot swappable I/O cards.

In addition, plants should evaluate, select and install a burner package that will guarantee a highly reliable efficient operation with excellent turndown capabilities.

Any equipment selected to meet the terms and conditions of this recommendation should be guaranteed under manufacturers' warranties.

Benefits

The estimated cost savings available by replacing the current burner controls and installing a new DCS, along with Option 1 recommendation, is $99,843. The dollar total is based on a 7 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 2 estimated payback is 3.3 years.

Option 3

Recommendation

Replace the existing boiler, burner and distributive controls system with I/O loop transmitters controls with new equipment with similar capacity as the original equipment. The boiler that is selected will have a steam capacity of 75,000 lb/hr at 350 psig/600°F superheated steam. The boiler will be equipped with a stack economizer. The burner should have a dual fuel capability (natural gas/propane with air atomization or natural gas/#2 fuel oil with steam or air atomization). With either burner that is chosen, it should be of the low excess air style to achieve highest efficiencies.

Benefits

The estimated cost savings available by replacing the existing boiler with a new boiler, new boiler controls and a new distributive control system with I/O loop transmitters is $121,238. The dollar total is based on an 8.5 percent (statistical industrial standard) decrease in the steam cost.

Costs

The Option 3 estimated payback is 10.5 years.

Steam Systems Improvement Proposal #1: Steam Trapping of "Fish Pond" Pipe Coils in Low Density Area

Background

The low density plant has a pit with steam heated pipe coils referred to as the "fish pond". The condensate from these pipe coils must be lifted (siphoned) to the steam trap. The current steam trap arrangement has a bypass around the trap without a valve. This bypass appears to be wide open, which allows "live" steam to be discharged into the condensate return line. The water hammer in the piping at this location is very evident.

Discussion

Elevating condensate up a lift in a siphon drainage situation will allow some of the condensate to flash back into steam. This flash steam will lead to sporadic trap operation and ineffective condensate drainage from the coil. In this situation, a bypass has been placed around the trap to route the flash steam around the steam trap. Currently, the amount of steam that is being routed through the bypass cannot be controlled. The current piping arrangement prevents the steam trap from functioning properly and leads to excessive steam waste. The discharge of live steam into the condensate system causes the water hammer noted above.

Recommendation

The condensate drainage on the pipe coils should be reconfigured to allow the use of a differential controller (DC) steam trap. The DC trap has an internal steam bleed that can be metered to control the flow rate of the bypassed steam. Condensate from the steam trap will be routed to a small receiver/pump package and then pumped back to the condensate receiver and pump package proposed in Steam Systems Savings Proposal #3. The proposed piping is shown in Figure 5.

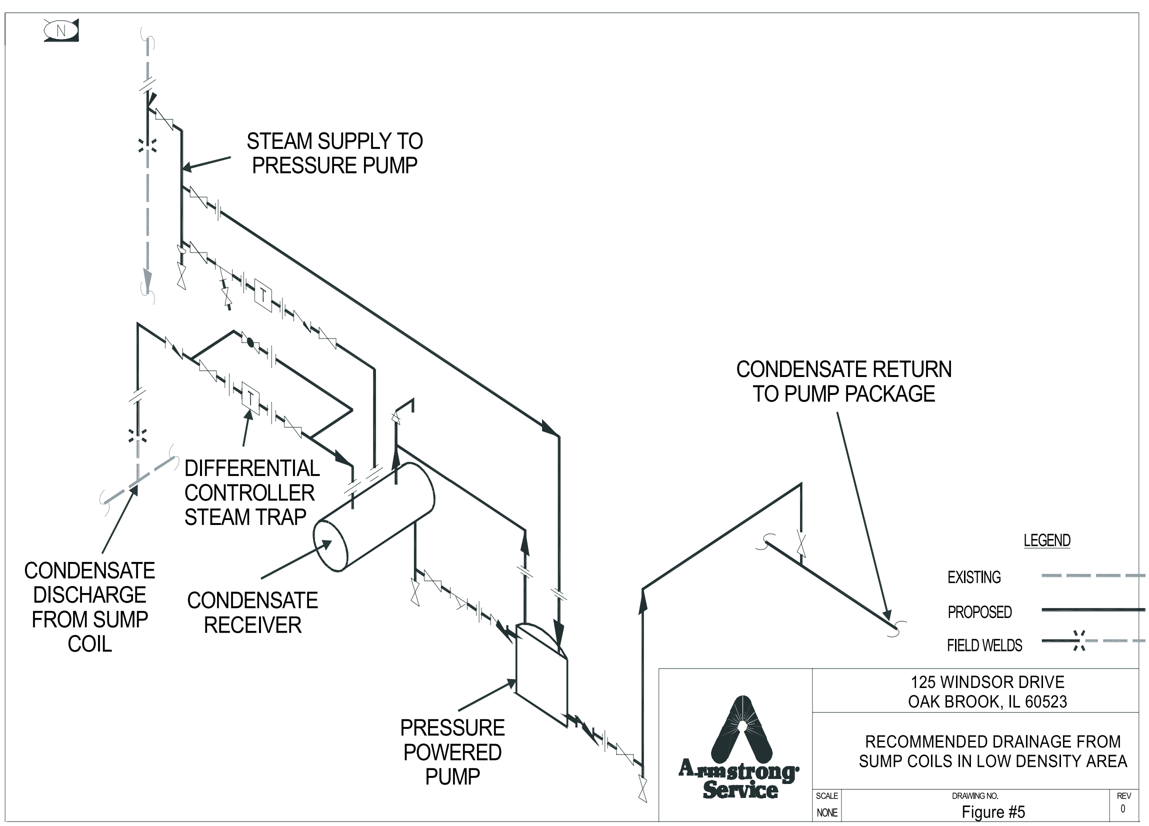
Estimated Benefits

The main benefits to this proposal will be improved coil performance and elimination of the water hammer. There will be a decrease in the amount of steam usage, but an estimate of the amount of steam being wasted cannot be obtained with the data available.

For more information contact:

Rich DeBat
Armstrong Service
Email: richd@armstrongservice.com
Phone: (616) 279-3360

Figure 5. Proposed Steam Trap Piping for "Fish Pond."



Steam System Diagnostics

John Todd, Yarway/Tyco

When steam system troubles arise, the steam trap is often unfairly assumed to be the problem.

Other factors that should be reviewed include steam trap technologies, piping design (upstream and downstream of the trap), system needs (for efficient operations), and trap maintenance (for optimum performance).

This article identifies some of the more common situations that occur along with possible solutions.

Steam Trap Technologies

- Match trap technology to application needs.

The first thing to recognize is that the steam trap is one part of a sometimes complex network of equipment. If the trap is concentrated on exclusively, the correction will probably just serve as a band-aid that will not last as a permanent solution to the problem.

Table 1 provides key performance characteristics that should be considered to meet specific application needs.

Let's start by stating the prime role of a steam trap: to remove condensate, air and other non-condensible gases, while not losing any live steam. If a trap fails, it should fail open to ensure that condensate will continue to be removed from the system.

The information in Table 1 makes it clear that application needs should be matched to the correct trap technology. Each trap type has its strengths and weaknesses and will give poor results if it is applied incorrectly.

There is no perfect trap technology for every application in every plant. Most major manufacturers have computerized trap sizing programs available to help the user optimize selection and prevent basic mistakes.

- Ensure that the steam being supplied is as dry as possible and contains the optimum Btu per lb. of latent heat for heat transfer.

Figure 1 readily displays the latent and sensible heat values in saturated steam at 100 psig. At this condition, it containes 309 Btu per lb. sensible heat and 881 Btu per lb. latent heat, all at a saturated temperature of 338° F.

As latent heat is used for heat transfer, it is best to be as close to the dry saturated point as possible, so as to use all the available Btu.

Many plants have less than ideal steam quality, often referred to as "wet steam." This means they are not as close to the dry saturated condition as possible.

This steam does not contain the maximum Btu available for optimum heat transfer.

For example, if a plant has steam with only 440 Btu per lb. of latent heat, it stands to reason that about twice as much of this steam will be needed to effect the same heat transfer.

This, in turn, creates a problem in that the trap must discharge twice the amount of condensate into what is often an undersized return line.

- Ensure that the piping allows the condensate to be removed effectively (Remember, water runs downhill.)

Figure 1. Total Heat in 100 psig Saturated Steam

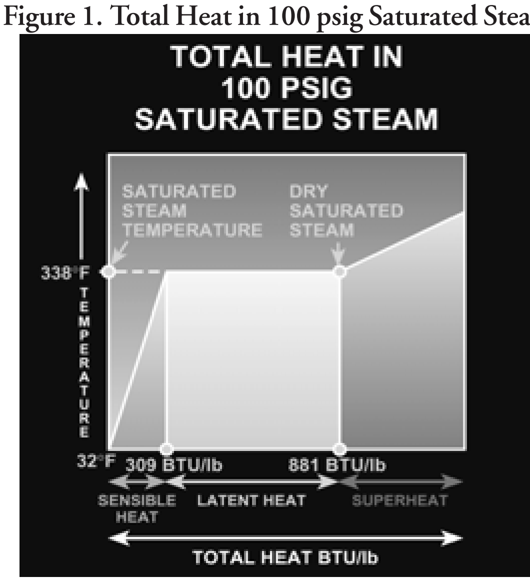
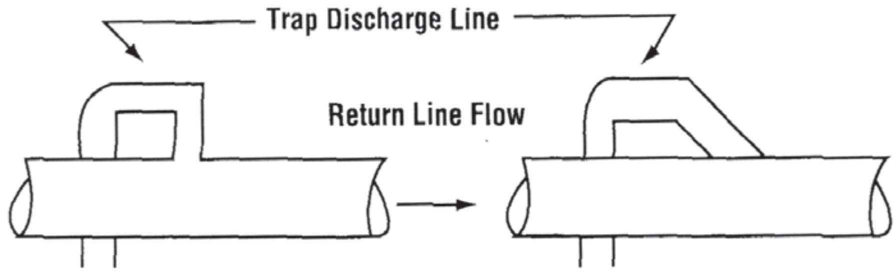


Figure 2. Trap Discharge Arrangements



Many plants have water hammer, and people become complacent about it, not realizing the damage it can cause to pipe work and associated equipment. It can also create a personnel safety hazard by leading to pipe breakage and possible escape of live steam.

Water hammer is caused by:

1. Slugs of water traveling down the pipeline at high speed. Steam has an average velocity of 8,800 ft per min. (100 mph).
2. Thermal shock created by mixing of cold and hot discharges.
3. Hydraulic shock (solenoid valves).

The first two are the most common causes and can be minimized by installing the correct drip pocket design/location and return line designs.

- Verify that the return line sizing is correct and ensure all line direction changes are taken into account when designing your piping.

After reviewing upstream piping, it is important to ensure that downstream design does not contain any restriction or introduce water hammer.

This is an increasing problem because more condensate is being returned to the boiler either because of EPA rules or for cost effectiveness.

How often do people take the time to check that the line is large enough to handle the condensate load? Correct sizing provides a return line that operates only partially full, creating a soft system.

Undersizing is like squeezing a quart of liquid into a pint container. This creates a higher return pressure, as well as water hammer, and leads to less efficient handling of condensate.

Also, the return line must never run uphill.

It is sometimes forgotten in piping design that raising the trap discharge by, say, 20 ft. to connect to pipework creates an energy drain.

Figure 3. Steam Line Drains

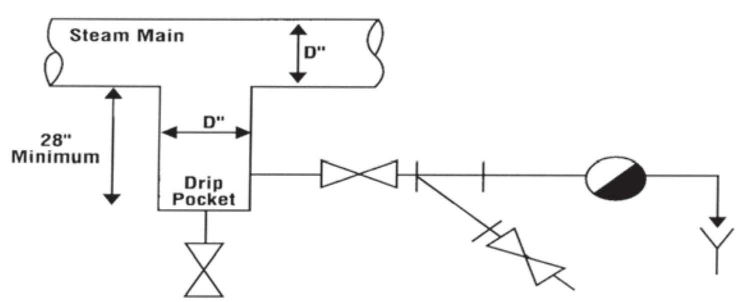


Table 1. Characteristics of Various Steam Trap Technologies

	Thermodynamic			Thermostatic			Mechanical	
	Disc	Piston	Lever	Bellows	Bimetallic	Pilot	Inverted Bucket	Float & Thermostatic
Discharge	cyclic	cyclic	cyclic	cyclic/ modulating	cyclic/ modulating	cyclic	cyclic/ modulating	modulating
Discharge Temperature	hot	hot	hot	hot/ subcooled	hot/ subcooled	hot	hot	hot
Air Venting	fair	good	excellent	excellent	excellent	excellent	poor	good
Dirt Handling	good	good	excellent	good/fair	fair	good	good	good
Superheat	excellent	excellent	excellent	good/fair	good	good	poor	poor
Water Hammer	excellent	excellent	excellent	good/fair	good	good	good	poor
Response	good	excellent	excellent	excellent	fair	good	good	excellent
Fail Mode	Open	open	open	open/close	open	open	open/close	closed
Freezing Susceptibility	no	no	no	no	no	no	yes	yes
Position Sensitive	no	no	yes	no	no	no	yes	yes
Back Pressure Sensitive	yes	yes	yes	no	yes	no	no	no

Back pressure is approximately 1/2 psi for each foot (e.g. 20 ft. is equal to 10 psi). This also lowers the differential pressure across the trap, thus reducing the volume of condensate it can pass.

Figure 2 demonstrates the correct positioning of trap discharges into the main condensate return line. They should always enter at the top, otherwise there will be mixing of hot and cold liquids, causing water hammer.

Trap Maintenance/Survey

Even with the correct type and size of steam trap installed, a maintenance program is essential to maintain optimum performance. Here are some pointers:

- Check traps at least annually.
- Verify trap operation by at least two of the accepted methods: visual, sound, temperature.
- Insulate lines but never the trap (you might not find an insulated trap and it could affect the trap's operation).
- Install the trap where it can be serviced easily (difficult loactions will not get checked).

If a steam trap is properly selected, sized, installed and maintained, it will provide many years of trouble-free service. However, it is important to remember tht the trap is only one part of the system, so careful attention should be paid to other equipment and conditions that could affect its performance.

For more information contact:

John Todd
Yarway/Tyco
Email: jtodd@tycoepg.com
Phone: (610) 832-2272

Steam Trap criteria/applications

While the main purpose of this article is to address the problems of steam systems, plant personnel also need to be aware of some steam trap specifics:

Sizing and selection

Steam trap sizing and selection criteria include the following:

- Technology.
- Operating pressure and discharge capacity.
- Ensuring that trap characteristics are suitable for the application discharge temperature.
- Venting ability.
- Suitability for drainage and pipe design.
- Freeze resistance.
- Ease of trap installation, checking and maintenance.

Applications

The three main applications for steam traps are listed below.

1. **Drip.** The purpose is to remove condensate from piping to prevent damage to the piping, control valves, strainers, etc., while assuring that production steam users receive dry steam. To achieve this, here are some check points (see Figure 3).

- Provide adequately sized drip pocket (28-in. minimum length) to match pipe size (e.g. on an 8-in. header, there should be an 8-in. diameter drain pocket).
- The trap connection should be on the side, about 6 in. from the bottom of the pocket to ensure that clean condensate is presented to the steam trap.
- Include a dirt blowdown valve at bottom of pocket to remove dirt or scale.
- Provide a trap every 300-400 ft.
- Locate drip pockets upstream of control valves, at all piping direction changes and, at the end of the line.

2. **Tracing.** This is the most maligned and least considered application, yet it is often vital and could be the subject of an article by itself. A few applications include process line tracing, winterization, instrument protection and steam jacketing. All of these have the common purpose of ensuring that efficient steam is distributed. Some points to remember are:

- Match tracing loads to tube size.
- Limit the tube run to 100 ft.
- Have only one trap per system.
- Make sure the trap is located at low point.
- Adequately insulate the line, not the trap.

3. **Process.** Depending on the application, the steam trap will probably have to handle heavy start-up loads, often followed by smaller running loads. The trap's function is to drain the process equipment and thus ensure that effective heat transfer is achieved (through latent heat). A few guidelines for optimum results include:

- Provide an adequate size process connection from equipment.
- Locate trap below the equipment (water runs downhill).
- Use good piping practice to ensure that clean condensate is presented to the trap (same rules as drip pocket).
- Include air vents and vacuum breakers as necessary for effective equipment operation.

NOMOGRAPH FOR ESTIMATING CONDENSATE RETURN LINE SIZE

Case I—What size return line is needed?

Given:
Trap inlet pressure, P_1 = 50 psig
Flash tank pressure, P_2 = 10 psig
Measured run of return line = 715 ft
Total trap capacity into line = 10,000 lb/hr

Solution:

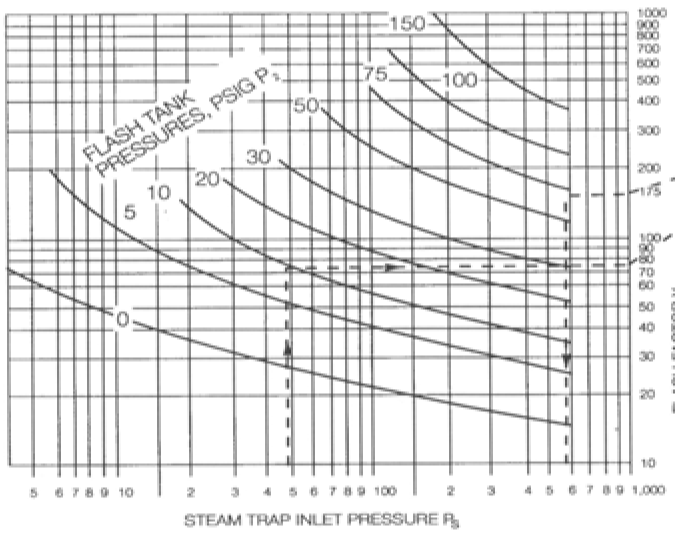
Connect	with	Read
P_1 = 50	P_2 = 10	X = 75
X = 75	W = 10,000	Y = 133
Y = 133	Le = 1,000	I.D. = 5-1/2 in.

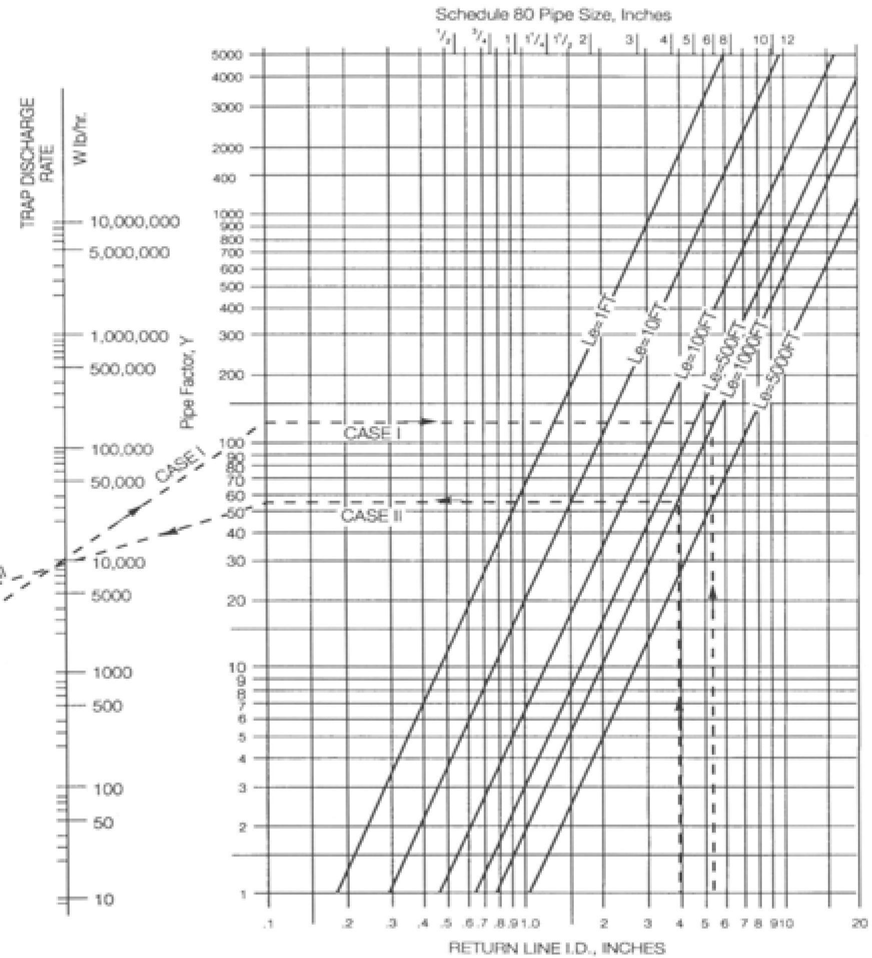
Case II—What is the maximum condensate rate in lb/hr that can be discharged into a given return line?

Given:
Trap inlet pressure, P_1 = 600 psig
Flash tank pressure, P_2 = 75 psig
Return line I.D. = 4 inches
Equivalent pipe length, Le = 1,000 ft
(including allowance for fittings)

Solution:

Connect	with	Read
P_1 = 600	P_2 = 75	X = 175
I.D. = 4 in.	Le = 1,000	Y = 55
X = 175	Y = 55	W = 10,000





Ultrasonic Testing Tips for Steam Traps and Valves

Bruce Gorelick, Enercheck Systems, Inc.

Abstract

Steam can exist anywhere in a system. Steam may be escaping through external or internal leaks in fittings, valves or controls, from oversized steam traps, or traps that are blowing, leaking or plugged with dirt.

Steam may be lost through uninsulated valves, flanges, sections of steam pipe, or through high back pressure in condensate lines caused by blowing traps. A control valve unable to close because of "wiredrawing" or undersized steam and condensate lines with no provision for utilizing flash steam could all be sources of wasted energy.

Testing Tips for Common Problem Areas

It is essential to know how each steam trap or valve works under specific conditions in order to be able to diagnose a problem correctly. To determine leakage or blockage, touch the ultrasonic instrument upstream of the valve or trap and reduce the sensitivity of the detector until the meter reads about 50. If you need to hear the specific sound quality of the fluid, simply tune the frequency until the sound you would expect to hear becomes clear. Next, touch downstream of the valve or trap and compare intensity levels and, for traps, sound pattern levels. If the sound level is louder downstream, then fluid is passing through. If the sound level is low, then the valve or trap is closed.

Check Valves

When check valves are placed closer than three feet downstream of blast action traps (such as inverted bucket or thermodynamic types) flappers may loosen or even break free. Damaged check valves will usually become noisy. When control valves are grossly oversized they are forced to work close to their seats. High velocity wet steam acts almost as sandpaper, cutting the seat when a mixture of steam and water is forced through the tiny crevice. With an ultrasonic instrument you can distinguish between normal machine noises and sounds that spell trouble. To verify data, use the instrument to test nearby units and compare.

Control Valves/Pressure-Reducing Valves

Air operated control valves may be leaking at or around their diaphragms. Scan the exterior sections listening for the turbulent sounds created by a leak. Test ultrasonically for internal leakage as you would for any other valve. It will be necessary to momentarily close the valve to perform definitive testing. For those valves with diaphragms, listen for leakage at the small bleed hole. This is a dead giveaway that a rupture has taken place.

Solenoids

Listen for leakage through solenoids that are in a closed position. You will be able to detect which valve is leaking even when it is part of a large bank of valves. If you are in doubt about a judgment call, compare with similar valves.

Relief Valve

In a steam system, relief valves that have opened by excess pressure may not reseat properly. Some with softer seats may be chattering or may suffer microscopic steam and water cuffing. Ultrasonic testing will detect the turbulent passage of steam or vapor as it moves through the leak site. Touch the instrument's stethoscope at the point on the valve closest to the orifice and then touch the downstream piping. Leaking and blowing valves are easily identified. Augment your test with a hand-held infrared thermometer for temperature differentials.

Condensate Return Pumps

Listen for the static noise indicating a vaporization bubble collapsing around the impeller. If in doubt, test similar pumps and compare. Remember to test volute pump casing temperatures with an infrared thermometer.

Pressure Powered Pump Needle Valves

The needle valves on steam or air powered condensate movers, like any other mechanism, will deteriorate over time. Listen for seepage of steam through worn valves, usually indicated by a high pitched whistling sound. When more then one pump exists, comparisons can be useful.

Valve, Piping and Gland Leakage

Use the ultrasonic instrument to scan all parts of the steam system for the sounds of turbulence. It will be a reality check to find out how many areas are actually leaking.

Conclusion

A maintenance program is critical in using steam efficiently. Implementing these simple steps can help any facility realize as much as a 34 percent saving on steam energy costs alone. Not many investments pay such high dividends. To establish an effective program, determine the optimum maintenance schedule for each trap and follow it. It would be difficult to find a less time-consuming program that is as cost effective.

Warnings of possible steam trap failure:

- An abnormally warm boiler room.
- A condensate receiver is venting excessive steam.
- A condensate pump water seal is failing prematurely.
- The conditioned space is overheating or under-heating.
- Boiler operating pressure is difficult to maintain.
- Vacuum in return lines is difficult to maintain.
- Water hammer.

For more information contact:

Bruce Gorelick
Enercheck Systems
Email: bjgorelick@mindspring.com
Phone: (704) 841-9550

Reliable Systems and Combined Heat and Power

David Jaber, (formerly with) Alliance to Save Energy
Richard Vetterick, TRC Energy

Abstract

Leading industrial companies and institutions are forever seeking new and better ways to reduce their expenses, reduce waste, meet environmental standards, and, in general, improve their bottom-line. One approach to achieving all of these goals is a 100 year-old concept, cogeneration or combined heat and power. Efficiency of cogeneration systems can reach 80 to 85 percent. Benefits of this throughout the plant include reliability enhancements and cost and emission reductions. Cogeneration schemes and systems can be modified to the plant design. The applicability of cogeneration to an industrial plant depends on the variations in steam and energy required for operation on both daily and yearly scales.

Cogeneration is receiving increased attention due to newer technologies that are making cogeneration opportunities available to smaller-sized thermal plants. Combined with electric utility deregulation opportunities, this is causing many industrial decision-makers to seriously consider cogeneration for their manufacturing plants. The advent of energy service companies has made financing of cogeneration projects attractive, helping to guarantee an acceptable return on investment.

Whether steam is created through cogeneration or separate generation, many opportunities exist to improve performance and productivity in steam generation, distribution, and recovery. These opportunities are captured by the systems approach promoted by programs such as the Department of Energy's (DOE) Steam BestPractices.

Introduction

Industrial and institutional plants need thermal energy, generally as steam, for manufacturing processes and heating. They also need electric power for motors, lighting, compressed air, and air conditioning. Traditionally, these fundamental needs are met separately. Steam is produced with industrial boilers and electricity is purchased from a local utility company. However, these needs can be met at the same time with cogeneration, using the same heat source and on a regional scale, greatly increasing the overall efficiency of energy generation.

Cogeneration is the concurrent production of electrical power and thermal energy from the same heat source. Large steam users commonly take advantage of cogeneration by using high pressure steam with a back pressure turbine to generate electricity, and extract lower pressure steam from the turbine exhaust for their process needs. This approach provides reliable energy while reducing their electric utility bills and providing thermal energy for industrial processes.

The steam turbine generators used by electric utilities require moderately high steam pressures and temperatures, with levels ranging as high as 4,400 psig. and 1,100° F respectively. This is expanded down to approximately 20 to 25 in Hg vacuum and 90° F to 100° F in the condenser, where the "latent heat of vaporization" is removed and discharged to the atmosphere, lakes, or rivers. Industrial processes are typically smaller systems using lower pressure and temperature levels, ranging down from approximately 1,000 psig. and 750° F to 150 psig. and 366° F (saturation temperature). The lowest heat intensity level processes are steam heating systems where pressures and temperatures of 15 psig. and 250° F are frequently utilized.

The Best of Both Worlds: Cogeneration

The steam generation cycle alone has a typical thermal efficiency of approximately 80 percent, depending on system loads, the fuel utilized, and the heat traps designed into the back-end of the boiler. Industrial boilers and utility boilers can achieve these efficiency levels while producing steam for their respective applications. Note that this efficiency level does not take into account the efficiency of the applications using the process steam or the efficiency of the steam distribution system.

Most utility thermo-electric steam power plants operate in the range from 30 to 40 percent efficiency depending on the throttle pressure and temperature, the number of reheater loops, the number of feedwater heaters utilized, and the type of heat traps utilized on the boiler. The gas turbine driven electric generator has historically operated in the high 20 to 30 percent range, but with today's high gas temperatures and compressor outlet pressures, the efficiency is ranging upwards of 35 percent. The latest utility power plant designs utilizing a combined cycle (a form of cogeneration) have high heat intensity gas power turbines exhausting into heat recovery boilers. Steam from these boilers then feeds a moderate heat intensity steam turbine generator. The combined operating efficiencies are in the 55 to 58 percent efficiency range. There are prototype designs being tested that exceed 60 percent.

However, modern industrial steam-electric cogeneration systems can boost overall thermal efficiency levels to an enviable 80 to 85 percent by recapturing enough waste heat from electricity-producing gas turbines to meet a portion of the industrial process requirements.[1] Typical non-industrial cogeneration users are college and university campuses, hospitals, municipal heating systems, and large commercial buildings. In addition to achieving high system thermal efficiency, steam-electric cogeneration systems can, if designed properly:

- Enhance the reliability of the power supply with on-site generating capacity to support operations during utility and electrical distribution line upsets.
- Reduce fuel costs by 15 to 20 percent by extracting more energy from the fuel when operating in the cogeneration format.
- Reduce or eliminate power purchases.
- Reduce overall emission levels from lower fuel use.
- Potentially provide additional revenue through sale of excess power to a district energy system or the utility electric grid.
- Maintain the high reliability of the single boiler process steam system by utilizing supplemental firing.

In terms of emissions and dollar savings, the difference between cogeneration and separate steam and electricity generation can be significant. Typically, cogeneration cuts fuel costs (which can range from 30 to 40 percent of the selling price of power) by increasing the amount of "salable product" per unit of energy.

Outlook

Cogeneration represents over half of all new power plant capacity built in North America in the last 10 years. This includes utilities and independent power producers (IPPs) as well as cogeneration by industrial companies and institutions. As of 1994, it accounted for 6 percent of total U.S. electricity-generating capacity. Of the electricity actually generated, 9 percent came from cogeneration.

Deregulation of the electricity market could open the door for renewed growth in cogeneration, but lots of potential utility and permitting-barriers still remain. Lower demand for electricity and increased utility resistance to industrial cogeneration are expected to diminish the prospects of seeing any new incentives for installing cogeneration.[2] However, utility deregulation and increasing concern about climate change are raising questions relative to the long-term availability and reliability of conventional power. These concerns and the availability of new low-cost generating technologies have piqued the interest of industrial and commercial customers with high thermal loads, high electricity rates, or both.

The deregulation opportunity is expected to present itself in two important areas: increased competition and increased marketability of low cost cogeneration-produced electricity. Increased competition in the electric market will result in lower electricity rates, which could make it more difficult for cogeneration projects to compete with larger utility companies. Again, this difficulty will vary across the country as electricity rates vary. Marketability of cogenerated power will increase because cogenerators will be able to sell excess power to customers other than their local utility. That means industrial cogenerators will be able to sell electricity to the public, to other industrials, to power brokers, and to distribution companies by wheeling it to them through the local utility's distribution system. Retail wheeling will be especially attractive in areas with very high electricity rates.

Types of Cogeneration Systems[3]

There are three basic types of cogeneration systems, categorized by the "prime mover" of the system: engine-based, steam turbine-based, and gas turbine-based. Each is briefly characterized below.

Engine-based System

Engine-based systems use an internal combustion engine to power a generator. Waste heat is reclaimed by sending exhaust to a steam generator, and by extracting heat from the engine and oil cooling systems. Since engine-based systems are only capable of producing low-pressure steam, they cannot be used by industries requiring pressure over 30 psig.

Of the three major types of cogeneration, engine-based systems possess the highest power-to-steam ratio.

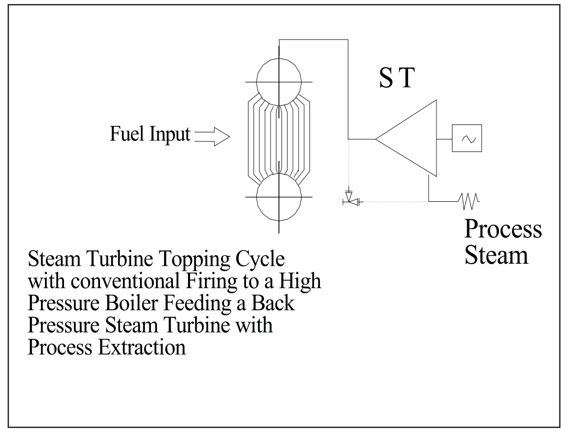
- Power-to-steam ratio: > 1.
- Size range: 10 kW – 16 MW; Typical size: 1 MW.
- Usable fuels: Gasoline and oil.

Unfortunately, engine-based cogeneration systems suffer from frequent breakdowns, thereby raising their operating and management costs, and increasing the costs of firm power back-up from local utilities. However, they have fairly low capital costs, simple operating and repair procedures, and good load-following ability. In terms of emissions, diesel engines produce substantial amounts of nitrous oxide (NO_x) and particulates while natural gas engines emit unburned hydrocarbons. Both types, however, emit low amounts of carbon monoxide (CO) and sulfur dioxide (SO_2).

Steam Turbine-based System

The steam turbine-based system relies on a conventional boiler to generate high-pressure steam. The high-pressure steam is then expanded across a high pressure turbine and the exhaust is routed to the process steam header. The high-pressure turbine generates electricity while functioning simply as a pressure reducing valve, providing the

Figure 1: Boiler with Backpressure Turbine



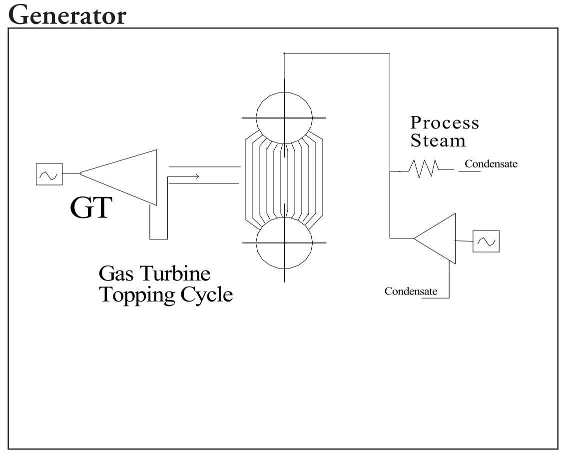
desired steam conditions to the process or heating system. The electrical power is generated at very high levels of thermal efficiency (95 to 96 percent) as there are no losses to the condenser. This is referred to as a backpressure turbine (see Figure 1).

- Power-to-steam ratios: 0.1-0.2.
- Usable fuels: Gas, coal, oil, natural gas, biomass, wood, municipal solid waste, or industrial waste.
- Size range: 10 kW – 400 MW, Typical size: 10 MW.

Back-Pressure Steam Turbine-Systems

These systems are good producers of heat, but low power producers. Therefore, they are particularly useful where large amounts of steam (a large thermal load) and moderate amounts of electricity (a low electric load) are needed. This system also allows for large electrical drive motors to be re-

Figure 2: Gas Turbine with Heat Recovery Steam Generator



placed with back-pressure turbine drives, thereby replacing electrical consumption with steam at approximately 90 percent efficiency. The steam turbine drives are durable, reliable, and good load-followers. Overall emissions depends on the fuel used to fire the boiler. Coal and biomass produce NO_x, SO_x, and particulates, while oil and natural gas produce CO and NO_x.

Gas Turbine-based System

Gas turbine systems use a conventional combustion turbine to generate electricity. After electricity is generated, the exhaust from the gas turbine is fed to a thermal process, such as a heat recovery steam generator, to produce steam (Figure 2).

- Power-to-steam ratios: 0.6 - 1.0.
- Usable fuels: natural gas and oil.
- Size range: .02 MW - 300 MW
  Typical size: 5 MW.

Gas turbines efficiently produce power, steam, and heat in concert and are, therefore, very attractive for cogeneration uses. However they require a high-quality fuel, are poor load-followers, and their technical complexity requires specially-trained staff to maintain them. In place of in-facility staff, smaller units can be offered with maintenance contracts and spare units kept available for quick changeouts.

Various elements of these systems can be combined depending on power and steam needs. For example, a combined-cycle gas turbine system could divert available steam to turn a steam turbine for more electricity, which can boost the power-to-steam ratio to the 1.5 range. Thus, when the process thermal load is down, the steam can be used for peaking power.

Is Cogeneration Right For You?

With today's technology developments in small gas turbines, along with the use of supplemental firing to support thermal peak loads swings, cogeneration is an economical and practical choice for small energy users as well as the large process industry users. As cogeneration attracts a larger base of applications, potential for improved energy efficiency and reduced environmental pollution increases. The DOE recently launched the Industrial Combined Heat and Power (CHP) Initiative to further enhance the adoption of cogeneration and related systems.

Characteristics of Facilities Well-Suited for Cogeneration

Industries that use consistent, simultaneous quantities of both electricity and steam with relatively high energy costs are the best candidates for cogeneration adoption. These often include food processing, chemical manufacturing, primary metals, commercial laundries, drywall manufacturers, and paper mills. Demand for both steam and electricity should be year-round and have an acceptable mix of loads over the course of a day. The key to success of these systems is the ability to match the size and loads of the combined electric and steam systems.

"This [cogeneration] project is an important step in increasing the overall efficiency and cost effectiveness of the operation at the Hawkins Point Plant." -***John Davis, Millennium Chemical***

A perfect fit is not likely to happen, and the system must be properly sized and engineered to achieve maximum efficiency, reliability, and operability. Numerous combined cycles have looked quite good on paper, only to fall short of their goal because the load requirements of the two systems didn't match as planned. Options in proper management of steam facilities include:

- Business as usual.
- Maintaining the status quo with implementation of best maintenance and operation practices.
- Upgrading to a cogeneration system.
- Outsourcing energy decisions to a third-party such as an energy services company.

Websites with more information on cogeneration include www.oit.doe.gov/chpchallenge and www.nemw.org/uschpa.

Systems Thinking

When considering which option to take, "systems" thinking offers the most advantageous way to operate a plant. Systems thinking applied to a facility involves looking at the overall plant resource and energy consumption and production to determine the areas in greatest need of optimization. It also applies to looking at systems individually. In incorporating systems thinking, it is useful to use The Natural Step (TNS).[4] TNS guides businesses in developing for their long-term future. It has a framework based on simple thermodynamic principles and has developed several tools as guides. One of these tools, the Compass, entails:

1. Visualizing how you would like to be operating decades into the future.
2. Assessing your current inputs, outputs, and operating practices.
3. Formulating a path to help you achieve this desired level by changing practices, policies, and operations.

This provides direction to the company as a whole. The same principle applies to energy systems. First, visualize how the steam system should be operating. Second, assess current operation. And third, identify the areas for improvement and the resources which allow them to be changed.

Cogeneration can be an integral part of the path to the ideal state of operation. However, the current state of practices and operations must already be conducive to making the move to cogeneration.

BestPractices

Systems thinking and identification of areas of improvement can often be difficult. Fortunately, a clearinghouse of resources has been established for steam system management. BestPractices Steam resources, offered by the DOE's Office of Industrial Technology (OIT) in conjunction with the non-profit Alliance to Save Energy, encourages a systems perspective that views individual energy-consuming components as part of a total system, focusing on the entire plant where significant savings can be found. Resources include tip sheets, case studies, lists of training courses, technical references and standards, assessment tools, and operational handbooks. These are available on-line or through the Industries of the Future (IOF) Clearinghouse, (800)862-2086.

What is BestPractices?

BestPractices brings together the best-available and emerging technologies, and practices to assist industries to improve their competitive position, of which steam is one component. Through the BestPractices approach, industry has easy access to both near-term and long-term solutions for their total manufacturing plant operations today. Any plant can realize near-term cost-effective energy savings between 10 to 30 percent in three to five years. By applying the best technologies and practices available, industry can:

- Prioritize energy efficiency investments for the greatest return on investment.
- Receive training, tools and documents to help implement projects.

The Industries of the Future Clearinghouse has more information on how to begin implementation of best practices.

Participation in BestPractices Steam efforts is open to steam system operators and managers, developers and distributors of steam systems equipment, as well as steam trade and membership organizations. This active participation ensures that BestPractices provides tools and resources that are valuable to industrial steam operators and managers. It also assists steam equipment and service providers, such as utilities, distributors, manufacturers, consulting engineers, and others promoting steam efficiency by serving as a valuable source of third-party, credible information.

Conclusion

With cogeneration achieving efficiency levels over 80 percent, fuel costs and emissions are lowered and additional profits are available from the sale of excess power. Advanced design and new technology has lowered generation capacity tremendously, to the point where even small plants can feasibly install cogeneration facilities. Cogeneration combined with the energy delivery improvements suggested by BestPractices Steam increases these benefits even more. However, before installing a cogeneration system there are several screening factors to be considered, including individual thermal profile, initial capital outlay, permitting standards, and readiness to be in the power provider business. Existing steam system components which support cogeneration equipment must be running as efficiently as possible. BestPractices Steam helps prepare industry for future cogeneration. In addition, the same wealth of benefits accrues for improved environmental and economic performance. While the future of cogeneration in states' deregulation remains hazy, it will continue to be a "power"ful generation option.

For more information contact:

Richard Vettrick
TRC Energy
Email: rvettrick@netscape.net
Phone: (330) 864-2549
Web address: www.trc-energy.qpc.com

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2. 1997 Industrial Cogeneration Report, Chapter 2, Gas Research Institute, Chicago, IL.
3. Ibid.
4. TNS is a movement dedicated to helping understand our social and environmental problems and moving beyond them by redesigning our interactions with our surroundings as businesses, communities, and individuals.

Business Benefits from Plant Energy Assessments and Energy Management

David Jaber, (formerly with)Alliance to Save Energy

Would you like to improve your process operations? Could you use an extra $100,000 to operate your textile mill? If so, an energy assessment and energy improvement project may be for you.

In pursuit of higher productivity and lower operating costs, M.J. Soffe, a producer of athletic clothing, recently assessed its steam, motor, and compressed air systems for improvement opportunities at their largest and most integrated manufacturing plant. The facility reports that it increased its throughput capacity by 37percent while reducing the energy needed per pound of product by 38 percent, saving $165,000 annually in fuel expenditures.

As with many energy projects, M.J.Soffe found that the benefits are not limited to utility and fuel cost savings, but also include improved productivity, increased equipment life, decreased risk of financial penalties, and increased order turnaround. A plant energy assessment identified the savings opportunities detailed in Table 1. Environmental emissions and penalty risks are also generally improved with energy efficiency projects. These projects are often low-risk investments and easily implemented. For example, when a Georgia Pacific plywood plant in Georgia insulated several steam lines leading to its pulp dryers and replaced steam traps, it lowered emissions of greenhouse gases and Clean Air Act pollutants by 9.5 million lbs of carbon dioxide (carbon equivalent), 3,500 lbs. of SOx, and 26,000 lbs of NOx on an annual basis.[2]

Importance of Energy Management

Because of the power of the plant audit to lead toward impressive improvements, the U.S. Department of Energy (DOE) partners with U.S. manufacturers to take a comprehensive, systems approach to increasing energy efficiency and savings opportunities, focusing on steam, motor, compressed air, combined heat and power, and process heating systems. On August 1, 2000, DOE re-opened a solicitation for industrial manufacturing plant-wide energy assessment proposals. Under the proposal, DOE shares up to 50 per-

Table 1. Sample Energy Assessment Findings

OPPORTUNITY	DESCRIPTION
Steam and Wastewater Heat Recovery	Costs of boiler fuel and treatment chemicals were artificially inflated by an inefficient water heating system that could not keep up with production surges. This resulted in thousands of gallons of hot water to be dumped and excessive steam and steam condensate waste. $140,000 annually was saved through increased steam condensate recovery and recovery of heat from the wastewater coupled with a steam trap maintenance plan. Heat recovery allowed reduction of steam generation pressure with only one boiler needed for production rather than two. Reduced steam pressure also means longer equipment life. Dyeing capacity increased by 37 percent, also increasing order turnaround, in a project with a 2.7 year payback time.
Motor and Compressed Air Systems	Risk of electric utility penalties was reduced by improving the plant power factor. This was done by implementing a motor purchase and replacement policy and more efficient motor utilities. Electricity costs also went down by $10,000 per year by joining two compressed air systems and turning off a large air compressor. The more reliable system requires less maintenance. [1]

cent of the plant assessment cost, up to a $100,000 limit. DOE also provides technical assistance, tools, and resources as desired by the company.

The true demands of energy production are significant. Steam systems, integral to many textile drying processes, account for approximately 35 percent of fuel used by U.S. textile manufacturing plants.[3] Further, the Alliance to Save Energy estimates that a typical plant can improve the efficiency of its steam system by 20 to 30 percent through opportunities in steam generation, distribution, end use, and recovery. Thus, the textile industry can particularly benefit by keeping steam systems in tune.

Resources for Improving Plant Performance

Many manufacturers may be interested in improved energy management, but where do they start? A collection of public resources is available for systems operations and maintenance. Although much commercial information focuses only on particular system components, DOE has established a library of information as a "one-stop shop" on entire plant energy systems. For example, in partnership with a public/private network of organizations and the Alliance to Save Energy, a national non-profit organization, many steam-system specific resources have been developed. The DOE offerings include:

- Sourcebooks that give a comprehensive system overview and reference sources for specific information.
- Best practice tip sheets with technical improvement suggestions.
- Case studies that highlight what leading companies have accomplished in business performance improvement.
- Training courses and commercial training course lists in motor, compressed air, and steam systems.
- Free plant audits for small and medium manufacturers through the Industrial Assessment Centers(IAC). The IACs are university teams composed of students and professionals.
- Software for motor management, optimizing insulation, screening pumps, and assessing plant cogeneration feasiblity.
- Deployment of state-of-the art emerging technologies developed by and for the paper industry and/or other manufacturing sectors.
- Technology research and development opportunities to help create tomorrow's technology for the manufacturing plant.

Additionally, a technical assistance hotline is available to answer many plant energy system questions through the BestPractices clearinghouse and website. Together, the Clearinghouse and the website allow access to the cost sharing agreement and all resources.

Steps for Better Performance

Step 1: Assessment

Go through your plant to look for savings opportunities. To help determine which systems offer the largest potential in savings, the DOE cost-share proposal enhances the financial appeal of energy auditing. Many private companies specialize in specific system auditing, and can help from there.

Step 2: Salesmanship to Financial Decision-Makers

Prepare an energy improvement project proposal in language compelling to upper company management. Part of this process is becoming knowledgeable on the financial criteria your company uses to screen projects, such as internal rate of return or return on assets. Meet with your company accounting and management staff. It can help to increase understanding of what each side needs and expects. It can also improve your project funding prospects.

It must be remembered that energy improvement projects may bring a host of plant changes, such as decreased downtime, a safer workplace, increased employee productivity, increased plant maintenance, plant productivity improvements, and decreased waste. A proper project proposal will attempt to quantify these savings and costs so the project impacts are clear to the financial decision-makers. The Alliance to Save Energy offers some guidance in this area.

Step 3: Implementation

Look at the DOE BestPractices website and call the Clearinghouse. Determine which of the resources are most likely to help you with plant improvements. Tip sheets are very useful in improving maintenance practices and are specific enough to offer guidance.

Step 4: Documentation

Record the project process and results. Documentation allows successful projects to be replicated throughout the company. It is important to share project benefits to help institutionalize the knowledge and experience gained, so others may follow where a few have led. Otherwise, success is dependent on a few people, who may or may not be available.

Step 5: Networking

Other companies can also have valuable insights on improvement. To the extent possible, networking between companies is a powerful way to discover what the best are doing and share successes. Networking gives access to the universe of successes which can benefit your operation. DOE will also partner with you to discover these external successful projects and help document your project in a case study.

Taking advantage of peer contacts, conferences, and workshops is invaluable in making these connections.

Conclusion

Too many manufacturing facilities are not achieving their full potential because of poorly-operating energy systems. Energy efficiency lies at the rarely visited intersection of improved economic performance, greater process efficiency, and environmental benefit—a win-win-win situation. By taking advantage of public and private energy management resources and following key steps in assessment, salesmanship to financial decision-makers, implementation, documentation, and networking, you, too, can realize success.

For more information contact:

Christopher Russell
Alliance to Save Energy
Email: crussell@ase.org
Phone: (202) 530-2225

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Use Spread-Sheet Based CHP Models to Identify and Evaluate Energy Cost Reduction Opportunities in Industrial Plants

Jimmy Kumana, Consultant

Abstract

CHP for (Combined Heat and Power) is fast becoming the internationally accepted terminology for describing the energy utilities generation and distribution systems in industrial plants. The term is all inclusive - boilers, fired heaters, steam turbines, gas turbines, expanders, refrigeration systems, etc.

A simulation model of the CHP system is an extremely useful tool to understand the interactions between the various components. Applications include:

- Identifying opportunities for cost reduction through efficiency improvement.
- Accurate energy cost accounting.
- Evaluating the energy cost impact of proposed process changes on the demand side.
- Comparison of cogeneration options.
- Identifying load shaping strategies (eg. switching between motors and turbine drives).
- Negotiating fuel/power supply contracts.

This paper describes how CHP models can be developed easily and at low cost using electronic spreadsheets, and illustrates their application with a detailed example.

Introduction

The "utilities" plant at an industrial manufacturing facility should more properly be called the Combined Heat and Power, or CHP, system. This is the prevailing terminology used in Europe and elsewhere in the world, and is increasingly being adopted in the USA as well. The CHP system includes all the elements involved in the generation and distribution of energy to drive the process and supporting infrastructure:

- Fired boilers.
- Waste heat boilers.
- Combustion air preheaters.
- Economizers (for BFW preheat).
- Blowdown flash tanks.
- Condensate recovery systems (steam traps, separators).
- Condensate mix tanks.
- Deaerators.
- BFW pumps.
- Back-pressure steam turbines.
- Pressure reducing stations.
- Desuperheating stations.
- Gas turbines, with or without heat recovery steam generators.
- Condensing steam turbines.
- Condensers.
- Cooling water circuits.
- Refrigeration systems (both mechanical and absorption type),etc.

The interactions between these various components can be very complex, and cannot be easily understood without constructing a reasonably accurate mathematical model.

Constructing the Model

A model is simply a set of equations and constraints that establishes the quantitative relationship between the key parameters of interest.

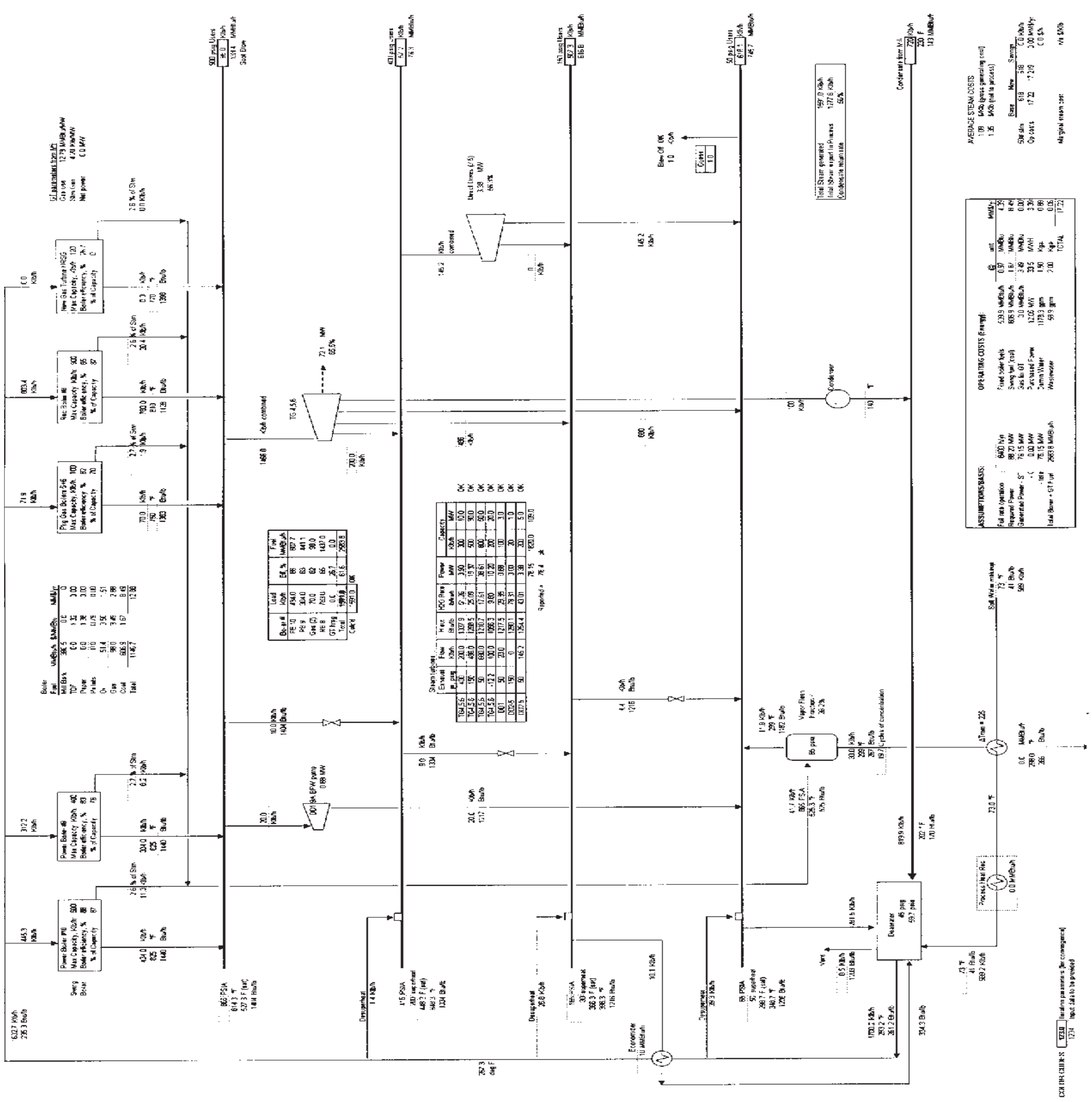
Consider the CHP system for a pulp/paper mill, as depicted in Figure 1, which incorporates many of the features found in a typical industrial facility.

The overall model has two distinct elements:

a) Models of individual items of equipment.
b) Computational strategy for interactions between equipment, that also reflects the operating policy.

It is beyond the scope of this article to describe all possible variations of equipment models, but some selected examples will illustrate the available options for the principal items.

Figure 1. Schematic Flowsheet of Combined Heat and Power System



Boiler Model One (Simple)

Operating mode = base load, constant efficiency

Input parameters = max operating capacity, operating pressure and temp, efficiency, blowdown rate (as percentage of steam generation), operating rate (percentage of max).

Equations:

1. Steam gen = capacity x operating rate
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown
4. Hs = f(P,T), from steam properties data base
5. Fuel input = Stm (Hs – h_{BFW})/h

Boiler Model Two (Simple)

Operating mode = swing, variable efficiency

Input parameters = max operating capacity, operating pressure and temp, blowdown rate (as percentage of steam generation)

Equations:

1. Steam gen = Total steam production required (trial value in overall computational algorithm) – combined steam generated in all other boilers
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown
4. Hs = f(P,T), from steam properties data base
5. Operating rate (%) = Stm gen / Capacity
6. Efficiency h = f(operating rate), equation to be provided by user, from manufacturer's data
7. Fuel input = Stm (Hs – h_{BFW})/h

Boiler Model Three (Rigorous)

Operating mode = base load

Input parameters = max operating capacity, operating pressure and temp, blowdown rate (as percentage of steam generation), operating rate (percentage of max), stack gas temp, combustion air supply temp, excess air ratio, radiative and convective heat losses

Equations:

1. Steam gen = capacity x operating rate
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown
4. Hs = f(P,T), from steam properties data base
5. Efficiency h = calculated from boiler heat and material balance
6. Fuel input = Stm (Hs – h_{BFW})/h

Back-Pressure Steam Turbine (Simple)

Operating mode = constant load and flow

Input parameters = Pi, Ti, Po, steam flow in (Klb/h), power output rate (kwh/Klb). The latter is calculated by the user from inlet and outlet pressures, inlet temp, and isentropic efficiency.

Equations:

1. Power, kw = output rate x steam flow
2. Hs,o = Hs,i – 3412/kw
3. To = f(Po, Hs,o), from steam props data base

Back-Pressure Steam Turbine (Rigorous)

Operating mode = load following, variable flow

Input parameters = Pi, Ti, Po, power output required, linked to process model, turbine performance curve (from manufacturer's data) that expresses the steam flow rate as a function of power output for the given Pi, Ti, and Po.

Equations:

1. Steam flow = f(required power output)
2. Hs,o = Hs,i – 3412/kw
3. To = f(Po, Hs,o), from steam props data base

Deaerator

Operating mode = steady state (see Figure 2 on next page)

Input parameters = condensate flow and temp from process, condensate flow and temp from condensing steam turbine, economizer duty, pressure of steam used in economizer, DA operating pressure, temp of makeup water (after preheating), vent vapor flow from DA

Equations:

1. Combined condensate flow, C = process cond + turbine condensate + economizer condensate

2. Mixed cond temp = sum (flow x temp) / sum (flow)
3. Assume Hv = Hs (this simplifies the model without significant error)
4. BFW flow, B = sum (feedwater flows to boilers) + sum (flows to desuperheating stations)
5. $SDA = \{C(h_M - h_C) + B(h_B - h_M)\}/(Hs - h_M) + V$
6. Makeup to DA, $M = B + V - C - S_{DA}$

Other Equipment

Similar models must be set up for the blowdown flash tank, desuperheating stations, etc.

Overall Algorithm

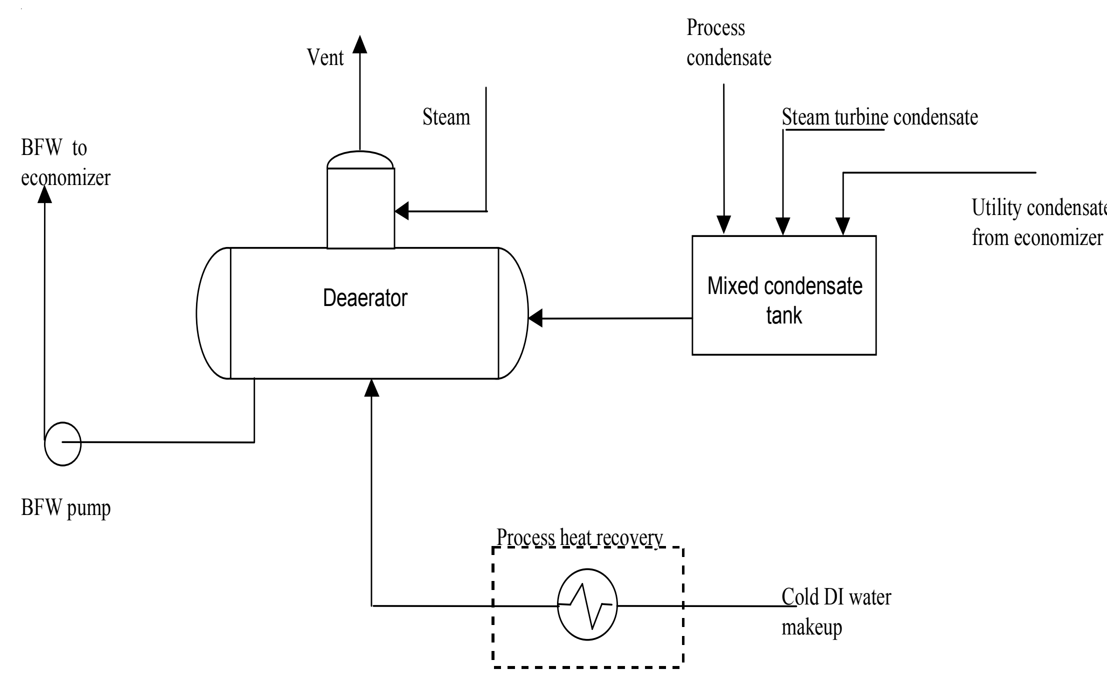
Now we need to tie all the various parameters together in an overall computational algorithm. It is recommended that heat losses due to radiation and leaks be excluded from the model, as they add a tremendous amount of computational complexity, make the model extremely difficult to debug, and do not offer compensating benefits. The typical error is about 3 percent, and this can be added on to the fuel cost.

Input parameters = operating pressure and temp of the various steam headers, process steam demands at the various pressure levels, steam flow rates to the back-pressure and condensing turbines, condensate return rate (flow), DI makeup water supply temp, estimated or allowable vent losses from LP header.
Calculation sequence:

Assume a trial value for total steam generation in the boilers, and then calculate the various parametric values from the "top down" by applying established principles for steady-state material and energy balances.

1. PRV flow from HP to IP = sum (steam from boilers) - process demand – sum (turbine outflows)
2. Calculate BFW flow to DSH station in IP header by simultaneous material and heat balance
3. PRV flow from IP to MP = sum (steam inflows) + DSH stm - process demand – sum (turbine outflows)
4. Calculate BFW flow to DSH station in MP header by simultaneous material and heat balance
5. PRV flow from MP to LP = sum (steam inflows) + DSH stm - process demand – sum (turbine outflows)
6. Calculate BFW flow to DSH station in LP header by simultaneous material and heat balance
7. Calculate flash vapor and net liquid blowdown flows from the BD flash tank, by heat/mass balance.

Figure 2. Schematic of Deaerator and Auxiliary Equipment



8. Calculate steam and makeup water flows to the DA from DA model
9. BFW temp = DA temp + economizer duty /B
10. Vent flow from LP header to atmos = sum (steam inflows) + DSH stm + flash vapor from BD tank - process demand – stm to DA
11. Heat recovery required against process hot streams = M x (DA feed temp – DI makeup water supply temp)
12. Calculate total steam generation required in boilers = sum (process demands) + flow to condensing path of steam turbine + steam to economizer + DA steam – BD flash vapor – sum (DSH flows) + LP vent to atmos

Compare the calculated steam generation requirement with the assumed trial value, and iterate until the two agree within the specified tolerance limit (eg. 0.1 Klb/h).

One note of caution – the user should be careful to ensure that the assumptions and data inputs do not result in infeasible solutions, such as reverse flows (ie from lower to higher pressure) across the PRV, and violating capacity constraints on the boilers and turbines.

Applications

Now let us consider some of the practical uses for this model.

First and foremost, we compare the calculated steam and power balance against measured (metered) values. If the two are not in reasonable agreement it means one of two things:

a) The meters need to be recalibrated.
b) The model is not an accurate representation of the plant, and needs to be corrected.

The error could be in the physical configuration, or in the assumptions about operating policy and/or leaks and heat losses.

Once the data have been reconciled, it is possible to begin analyzing the system for opportunities to improve efficiency. The first thing we look for is shifting flow from PRVs to steam turbine generators. In Figure 1, we see that the PRV flows are already very small, and that the opportunity to make more power in the back-pressure STs is limited.

We next turn our attention to condensing steam turbines. These are usually "Across the Pinch," and not cost effective for base load operation. The model shows however that if the condensing flow were reduced to the minimum of 20Klb/h, the operating cost would go up by $630K per year, which is counter to expectation. This is because the swing fuel being used is coal (in power boiler #10), which is extremely cheap.

If the swing fuel were gas, however, then the cost savings would be $910/yr, which is more typical, and would be accomplished by shutting down package boilers #5 and 6. The model shows that nearly a million dollars a year (including maintenance and operating labor cost savings) could be achieved by minimizing flow through the condensing section of the turbines, at zero capital cost.

The next idea we explore is to increase the duty on the economizer, e.g. from 10 MMBtu/h to 30 MMBtu/h. This will mean adding additional heat transfer surface. However, the model shows that the cost savings are non-existent, because the incremental power credit is almost exactly offset by the extra cost of fuel. Thus at current fuel and power prices, there is no incentive to spend any engineering resources on repairing/revamping the economizer. In fact, the model shows that the economizer could be taken out of service with no penalty at all. This insight would probably have eluded us without a model.

Such preliminary screening allows us to focus on the projects that are attractive, and cast aside ones that are not. We can simultaneously evaluate the potential benefits of common energy conservation and efficiency improvement measures such as increasing the condensate recovery rate, preheating BFW makeup water to the DA, and reducing steam consumption in the process through heat recovery.

For example, increasing condensate recovery from 56 percent to 70 percent saves 410 K/yr, while adding an exchanger to recover 5.5 MMBtu/h of heat from boiler blowdown saves about $110K/yr, and further preheating BFW makeup by 26 MMBtu/h to 150°F (against process waste heat) saves another $190K/yr. It may appear odd that

Table 1. Summary of Cost Savings from Various Projects

	Case Number								
	0	1	2	3	4	5	6	7	8
Economizer duty, MMBtu/h	10	10	10	30	0	10	10	10	10
Condensate recovery, %	56	56	56	56	56	70	70	70	70
DA feedwater temp, F	73	73	73	73	73	73	150	150	150
Heat rec into DFW, MMBtu/h	0	0	0	0	0	0	31.5	26.7	26.7
Process LP steam savings, Klb/h	0	0	0	0	0	0	0	200	200
Total boiler steam gen, Klb/h	1591	1479	1477	1494	1468	1439	1380	1270	1162
Fuel consumed, MMBtu/h									
Coal	607	450	545	557	538	492	409	86	8
Gas in boilers	98	98	0	0	0	0	0	0	0
Gas Gas Turbine	0	0	0	0	0	0	0	0	248
Total	705	548	545	557	538	492	409	86	256
Turbogenerator steam flows									
HP to IP	200	200	200	200	200	200	200	200	200
HP to MP	486	486	486	505	480	486	486	486	486
HP to LP	680	646	646	643	643	608	549	330	330
HP to condensing	100	20	20	20	20	20	20	20	20
Total	1466	1352	1352	1368	1343	1314	1255	1036	1036
Toal power generated, MW	76.2	66.1	66.1	66.6	65.6	63.9	60.6	48.1	61.7
Operating cost, MM$/yr	17.22	17.85	16.31	16.32	16.32	15.91	15.61	14.56	16.93
Cumulative savings, MM$/yr	0	-0.63	0.91	0.90	0.90	1.31	1.61	2.66	0.29
Incremental savings, MM$/yr	0	-0.63	1.54	-0.01	0.00	0.41	0.30	1.05	-2.37

Case Number	Description
0	Base case-existing operation
1	Minimize condensing turbine flow, cut back on coal fired boiler
2	Minimize condensing turbine flow, cut back on gas-fired boilers (can be shut down)
3	Increase economizer duty to 30 MMBtu/h
4	Reduce economizer duty to zero
5	Increase condensate recovery from 56 percent to 70 percent
6	Raise DA feedwater temp to 150° F by heat recovery against process
7	Reduce LP steam demand in process through heat recovery (Pinch Analysis)
8	Add new 15 MW Gas

Note: Numbers in bold in the table are the primary changes made in each case listed.

the cost savings are not proportional to the heat recovery rate. This is because the reduction in steam generation comes from different boilers which have different efficiencies, an effect that would have been difficult to predict without the model.

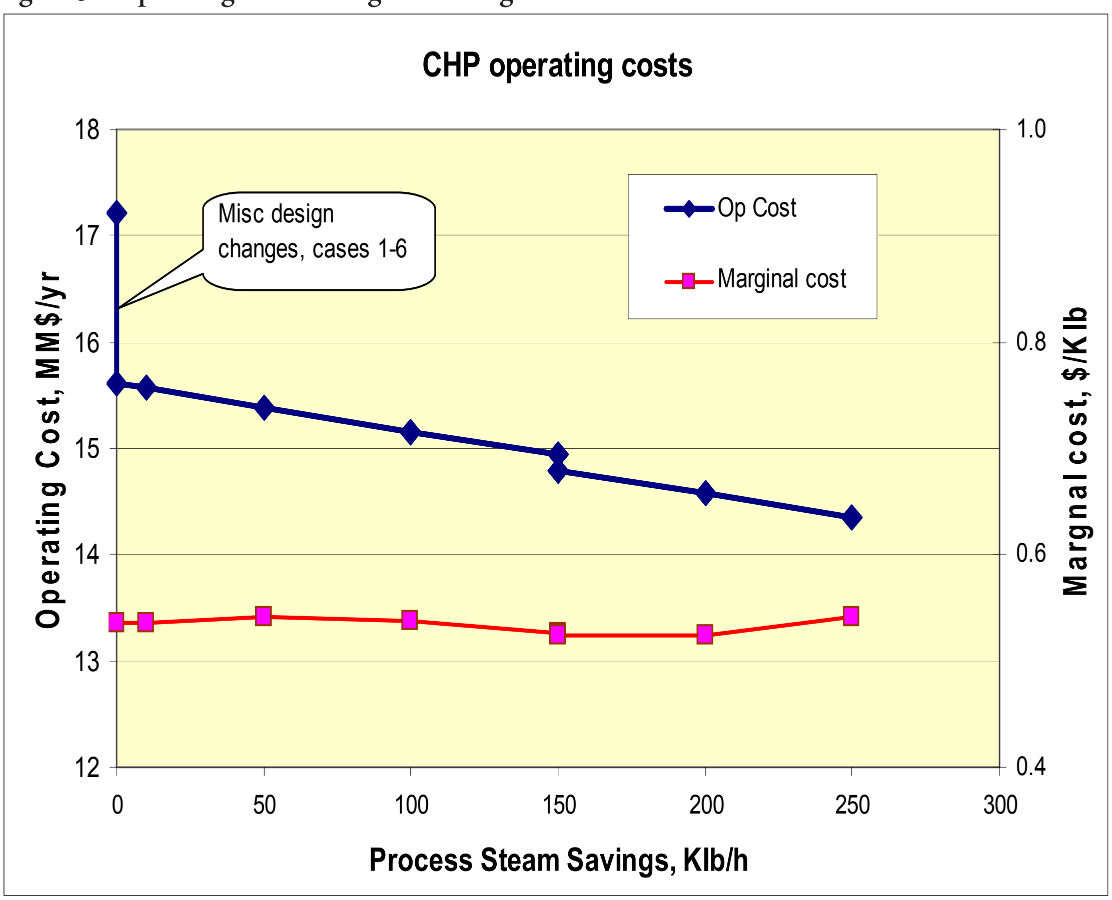
In recent years, cogeneration projects involving gas turbines have become very popular. The model can be used to quickly check whether such a project would be appropriate for local site conditions. The key parameters (heat rate and steam/power ratio) for the machine being considered must be provided as input. The model shows that energy operating costs actually increase by $2.37 MM/yr, because the power:gas cost ratio is not favorable, and so this project can be immediately rejected without further waste of time.

One must keep in mind that the foregoing conclusions are valid only for the fuel/power costs and equipment capacity/efficiency numbers that have been used. Under a different set of technical and economic conditions, the optimum operating policy could be quite different. The estimated cost savings and key parameters for all of the various projects discussed above are summarized in Table 1.

Finally, we can postulate various levels of steam savings in the process, in steps of 50 Klb/h, and develop a curve showing the net cost savings and the marginal cost of steam. Figure 3 shows the marginal cost of steam savings is constant over the entire range of 0-250 Klb/h, which is somewhat atypical. Normally, there will be several step changes in the marginal cost curve, reflecting changes in fuel mix (eg. gas vs coal) and boiler efficiency as the high cost boilers are shut down, changes in steam path (eg. PRV versus ST) due to capacity limitations, or changes in power cost structure as due to contractual constraints.

It is important to recognize that the cost savings achieved are a function of the order in which the projects are implemented. Generally, the earlier projects will have proportionately larger savings, and the later ones will have smaller savings.

Figure 3. Operating Cost Savings and Marginal Cost of Steam



One of the most powerful applications of such models is their use for on-line real time optimization of the operating policy for the CHP system. This has been done at many of the manufacturing sites owned by progressive companies like Union Carbide, BASF, and Chevron.

CONCLUSION

CHP simulation models are a convenient and reliable tool to evaluate ideas for efficiency improvement and cost reduction. They provide accurate estimates of operating costs, and can be used for online real-time optimization.

The cost of developing a model using electronic spreadsheets is very modest (in the range of $10 – 20K, depending on complexity) compared to the potential benefits.

It is recommended that this tool be adopted by industry for energy cost accounting and to improve energy efficiency, with attendant reduction in operating cost and emissions of greenhouse gases to the environment.

For more information contact:

Jimmy Kumana
Consultant
Email: jkumana@aol.com
Phone: (713) 260-7235

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NOMENCLATURE

H	enthalpy of steam
h	enthalpy of liquid
kw	kilowatts
kwh	kilowatt-hours
P	pressure
S	steam (flow parameter)
T	temperature
V	vapor (flow parameter)
h	efficiency, percentage

ABBREVIATIONS

BD	blowdown
BFW	boiler feed water
DA	deaerator
DI	De-ionized (water)
DSH	desuperheating
HP	high pressure
i	inlet (as subscript)
IP	intermediate pressure
K	1000
L	liquid (as subscript)
LP	low-pressure
MM	million
MP	medium pressure
o	outlet (as subscript)
PRV	pressure reducing valve
S	steam (as subscript)
ST	steam turbine
V	vapor (as subscript)

Justifying Steam Efficiency Projects to Management

Christopher Russell, Alliance to Save Energy

Abstract

Industrial plant engineers often must convince top management that investing in steam efficiency is an effort worth making. Communicating this message is often more difficult than the actual engineering behind the concept. A corporate audience responds more readily to a dollars-and-cents impact than to a discussion of Btus and efficiency ratios.

By adopting a financial approach, the plant engineer relates steam efficiency to corporate goals. Collaborating with the financial staff yields the kind of proposal that is needed to win over corporate officers who have the final say-so over such capital investments as steam system upgrades.

Before any recommendations can be made about how to justify steam improvement projects, it is first necessary to understand the world as management typically sees it.

Understanding Corporate Priorities

Corporate officers are accountable to a chief executive, a board of directors, and an owner (or shareholders, if the firm is publicly held). These officers create and grow the equity value of the firm. The corporation's industrial facilities contribute to this equity by generating products with a market value that exceeds the cost of owning and operating the plant itself.

Plant equipment—including steam system components—are assets that must generate an economic return. The annual earnings attributable to the sale of goods produced by these assets, divided by the value of the plant assets themselves, describe the rate of return on assets. This figure is a key measure by which corporate decision makers are held accountable.

Financial officers in particular are conservative decision makers. They shun risk and resist spending money on the plant itself, if possible. When forced to do so, they seek investments that are most certain to demonstrate a favorable return on assets. When presented with multiple investment opportunities, they favor those options that lead to the largest and fastest returns.

This corporate attitude may impose sometimes-unpleasant priorities on the plant engineer or facility manager. Priorities include reliability in production, avoiding unwanted surprises by primarily adopting familiar technology and practices, and contributing to cost control today by cutting corners in maintenance and repair. No wonder industrial decision makers often conclude that steam efficiency is a luxury they cannot afford.

Fortunately, the story does not end here. Industrial steam efficiency can save money and contribute to corporate goals while effectively reducing energy use and unwanted noxious combustion emissions in a variety of ways.

Measuring the Dollar Impact

Steam system improvements can move to the top of the list of corporate priorities if the proposals respond to distinct corporate needs. The number and variety of corporate challenges open up many opportunities to promote steam efficiency as a solution. And steam systems offer many opportunities for improvement. Once target areas have been selected, the proposals need to be dressed in corporate, dollars-and-cents language.

The total dollar impact of the measure must be identified and quantified. One framework to use is life-cycle cost analysis. This analysis captures the total expenses and benefits associated with an investment. The result—a net gain or loss on balance—can be compared to other investment options or, if no investment is made, to the anticipated outcome. When used as a comprehensive accounting of an investment option, the life-cycle cost analysis for a steam efficiency measure includes several elements:

- Search and selection costs of choosing an engineering implementation firm.
- Initial capital costs, including installation and the costs of borrowing.
- Maintenance costs.
- Supply and consumable costs.

- Energy costs over the economic life of the implementation.
- Depreciation and tax impacts.
- Scrap value or cost of disposal at the end of the equipment's economic life.
- Impacts on production such as quality and downtime.

A typical boiler installation illustrates this approach. The analysis assumes a 20-year life operating at high rates of capacity utilization. Fuel costs may represent as much as 96 percent of life-cycle costs, while the initial capital outlay is only 3 percent and maintenance a mere 1percent. Clearly, any measure that reduces fuel consumption (while not negatively affecting reliability and productivity) certainly yields positive financial impacts for the company.

Presenting Efficiency Economics

As with any corporate investment, there are many ways to measure economic impacts. Some are more complex than others and proposals may use several analytical methods side-by-side. The choice of analyses depends primarily on the sophistication of the presenter and the audience.

A simple (and widely used) measure of project economics is the payback period. This term is defined as the period of time required for a project to break even. It is the time needed for the net benefits of an investment to accrue to the point where they equal the cost of the initial outlay.

For a project that returns benefits in consistent, annual increments, simple payback equals the initial investment divided by the annual benefit. Simple payback does not consider the time value of money. In other words, it makes no distinction between a dollar earned today and one earned in the future, making earnings figures uncertain. Still, the measure is easy to use and understand, and many companies use it for making a quick decision on a project. The following factors are important to remember when calculating a simple payback:

- The figure is approximate. It is not an exact analysis.
- All benefits are measured without considering their timing.
- All economic consequences beyond the payback are ignored.
- Payback calculations do not always find the best solution (because all factors are not considered).
- Payback does not consider the time value of money or tax consequences.

More sophisticated analyses take into account such factors such as discount rates, tax impacts, and cost of capital. One approach involves calculating the net present value of a project, which is defined by the equation:

$$NPW = PWB - PWC$$

NPW (net present worth)
PWB (present worth of benefits)
PWC (present worth of costs)

Another commonly used calculation for determining economic feasibility of a project is internal rate of return. It is defined as the discount rate that equates future net benefits (cash) to an initial investment outlay. This discount rate can be compared to the interest rate at which a corporation borrows capital.

Many companies set a threshold (or hurdle) rate for projects. This rate is the minimum required internal rate of return for a project to be considered viable. Future benefits are discounted at the threshold rate, and the net present worth of the project must be positive for the project to be given the go-ahead.

Relating Steam Efficiency to Corporate Priorities

Saving money, in and of itself, should be a strong incentive for increasing steam efficiency. Still, that may not be enough for some corporate observers. The case can be strengthened by relating a positive life-cycle cost analysis to specific corporate needs. Consider the following suggestions for interpreting the benefits of fuel cost savings:

- **A new source of permanent capital**. Reduced fuel expenditures—the direct benefit of steam efficiency—can be thought of as a new source of capital for the corporation. An investment that reduces fuel costs yields savings each year over the economic life of the improved steam system. Regardless of how the investment is financed (borrowing, retained earnings, or third-party financing), the annual savings are a permanent source of funds as long as the savings are maintained on a continuous basis.

- **Added shareholder value.** Publicly-held corporations usually embrace opportunities to enhance shareholder value. Steam efficiency is an effective way to capture new value.

  Shareholder value is the product of two variables: annual earnings and price-to-earnings (P/E) ratio. The P/E ratio describes the corporation's stock value as the current stock price divided by the most recent annual earnings per share.

  For a steam efficiency proposal to take advantage of this measure, it should first identify annual savings (or rather, addition to earnings) that the proposal will generate. Multiplying that earnings increment by the P/E ratio yields the total new shareholder value that can be attributed to the steam efficiency implementation.

- **Reduced cost of environmental compliance.** Plant engineers can promote project benefits as a means of limiting the corporation's exposure to environmental emissions compliance penalties. Efficient steam systems lead to better monitoring and control of fuel use. Combustion emissions are directly related to fuel use. They rise and fall in tandem. Implementing steam efficiency lets the corporation enjoy two benefits: decreased fuel expenditures per unit of production and fewer emission-related penalties.

- **Improved worker comfort and safety.** Steam system optimization requires ongoing monitoring and maintenance that yields safety and comfort benefits in addition to fuel savings. The system monitoring routine usually identifies operational abnormalities before they present a danger to plant personnel. Containing these dangers minimizes any threats to life, health, and property.

- **Improved reliability and capacity utilization.** Another benefit of steam efficiency is more productive use of steam assets. The efforts required to achieve and maintain energy efficiency largely contribute to operating efficiency. By ensuring the integrity of steam system assets, the plant engineer can promise more reliable plant operations. From the corporate perspective, a greater rate of return on assets is achieved in the plant.

Taking Action

The following steps can help make a proposal for steam efficiency implementation attractive to corporate decision-makers:

- Identify opportunities for achieving steam efficiency.
- Determine the life-cycle cost of attaining each option.
- Identify the option(s) with the greatest net benefits.
- Collaborate with the financial staff to identify current corporate priorities (added shareholder value, reduced compliance costs, improved capacity utilization, etc.).
- Generate a proposal that demonstrates how the benefits of the steam efficiency project directly responds to current corporate needs.

For more information contact:

Christopher Russell
Alliance to Save Energy
Email: crussell@ase.org
Phone: (202) 530-2225

Steam Champions in Manufacturing

Christopher Russell, Alliance to Save Energy
Anthony Wright, Oak Ridge National Laboratory

Abstract

Traditionally, industrial steam system management has focused on operations and maintenance. Competitive pressures, technology evolution, and increasingly complex regulations provide additional management challenges. The practice of operating a steam system demands the managerial expertise of a "steam champion," which will be described in this paper. Briefly, the steam champion is a facility professional who embodies the skills, leadership, and vision needed to maximize the effectiveness of a plant's steam system. Perhaps more importantly, the steam champion's definitive role is that of liaison between the manufacturer's boardroom and the plant floor. As such, the champion is able to translate the functional impacts of steam optimization into equivalent corporate rewards, such as increased profitability, reliability, workplace safety, and other benefits. The prerequisites for becoming a true steam champion will include engineering, business, and management skills.

Introduction

Steam is a significant feature of industrial power. Steam systems account for approximately two thirds of primary fuel consumption in manufacturing. In 1995, this consumption totaled 9.34 billion quads[1], costing $21 billion (Jones 1997). Steam continues to be an ideal medium for applying thermal energy in ways that transform, distill, shape, and cure material works in process.

Usually, plant managers perceive steam to be a utility that supports core process activities. While plant managers may attribute value of output solely to process applications, no such attribution is given to steam utilities. Regardless of whether that view is warranted, it also implies that plant managers do not think of steam systems as a source of additional value to be captured. In this scenario, the steam manager's job is simply to ensure a reliable supply of steam. At worst, this suggests that some managers are oblivious to the opportunities to control steam system operating costs.

However, the optimization of industrial steam systems is a worthwhile pursuit that returns real value to the asset owners. In order to achieve this, steam systems will require management that is more sophisticated than what was required in the past. The operations aspect of steam optimization will include proper system design, balancing[2], maintenance, and repair procedures. Increasingly, however, business priorities enter the steam management agenda.

Competition and cost pressures demand that manufacturers squeeze value from plant expenses while still generating revenue from marketable products. Meanwhile, new technologies emerge that can enhance steam system productivity. Other technologies pose threats as substitutes to steam applications. At the same time, steam management is made more complicated by the imposition of environmental regulations and operator certifications. A more sophisticated manager—a "steam champion"—is the professional equipped with the skills, leadership, and vision necessary to manage the forces that now characterize industrial steam operations.

Steam Champion: Major Management Functions

The qualities of a steam champion may be best described by an overview of his or her managerial functions and concerns. The steam champion's major activity groups are discussed in the sections that follow. These include:

1. **Performance management:** the strategic evaluation of plant functions relative to industry peers or benchmarks.
2. **Operations management:** the identification and implementation of maintenance and operations processes that ensure reliable steam output.

[1] A "Quad" is one quadrillion (or 10^{15}) Btu.
[2] "Balancing" refers to the continuous process of adjusting the volume of steam to be generated against the loads demanded of the system. A perfectly balanced system experiences no excess or shortage of steam load.

3. **Personnel management:** the employ and development of human resources as needed to perform system operations.
4. **Business management:** the analysis and communication of steam system performance in relation to business priorities and goals.
5. **Planning:** the anticipation of changes in the business environment, including new technologies, regulations, market conditions, and human resource issues.

Performance Management

Performance management is the first step in optimizing a steam system relative to best-in-class standards. Several key operating metrics[3] allow (1) comparison among systems within the same industry and (2) comparison of one system's performance over periodic intervals. While the sharing of data with competitive firms is usually problematic, professional engineering societies, local utilities, or manufacturing assistance programs may help in this regard. Operations benchmarking may also be accomplished if a plant is one of many belonging to the same corporate group.

The true effectiveness of steam operations can be evaluated with a couple of fundamental metrics. The cost per thousand pounds of steam produced is one comprehensive measure of steam system operating expense. Steam's contribution to plant output is another potential metric, and can be expressed as pounds of steam required per unit of production. The comparison of these metrics to industry standards provides a relative measure of a steam plant's operating condition. Knowledge of the steam plant's relative performance is a prerequisite to implementing an ongoing optimization program. Table 1 (see below) suggests the steam champion's checklist of performance management items.

Operations Management

Operations management involves the identification and implementation of improvement opportunities. Some activities are remedial or reactive in nature, such as fixing leaks. Others are routine, such as monitoring and recording performance data. Still others are proactive, requiring the investment in new equipment that will enhance productivity. Optimized steam systems deliver thermal resources with a minimum of loss from the boiler to the plant's process applications. Best-in-class or benchmark comparisons help to identify the features of an optimized system. Reference to such comparisons should lead directly to the formulation of an operations management program, having system optimization as its goal.

The steam champion's operations management program requires diligent monitoring and maintenance. This provides system reliability and also ensures that potentially dangerous anomalies are discovered and corrected before personnel are harmed. Disciplined operations preclude downtime, allowing the plant to demonstrate greater productivity. Proper combustion, water treatment,

[3] A metric is a variable or a ratio of variables that records the performance of a chosen feature for each of many different observations. For example, boiler efficiency compares the Btu content of a boiler's steam output to the Btu content of the fuel consumed to produce that steam. Boiler efficiency is a metric because it can be recorded and compared (1) for many boilers, or (2) repeatedly for the same boiler at regular intervals.

Table 1. Steam Champion's Performance Management Checklist Adapted from (Wright 2001).

Steam Costs	■ Monitor fuel cost to produce steam in ($) per 1000 lbs. of steam. ■ Calculate and trend fuel cost to generate steam.
Steam/Product Benchmarks	■ Measure steam/product benchmark: lbs. steam required per unit of production. ■ Trend steam/product benchmark with periodic measurements.
Steam System Critical Parameter Measurements	■ Steam production rate. ■ Fuel flow rate. ■ Feedwater flow rate. ■ Makeup water flow rate. ■ Blowdown flow rate. ■ Chemical input flow rate. ■ Intensiveness of steam flow metering (by plant, building, process unit, etc.).

Table 2. Steam Champion's Operations Management Checklist Adapted from (Wright 2001).

Steam System Operating Practices	
Steam Trap Maintenance Program	■ Select proper trap for application. ■ At least annual testing of all traps. ■ Maintain a steam trap database. ■ Repair/replace defective traps.
Water Treatment Program	■ Ensure that water treatment system functions properly. ■ Measure conductivity and blowdown rates for boiler and mud drum.
Steam Insulation	■ Ensure that boiler refractory and insulation on pipes, valves, flanges, etc. are in good condition. ■ Ensure that steam distribution, end use, and recovery equipment insulation is in good condition.
Steam Leaks	■ Record frequency of leaks. ■ Establish an order of loss magnitude for leaks. ■ Establish system and timetable for repairing leaks.
Water Hammer	■ Note frequency of water hammer episodes. ■ Ability to remedy water hammer.
Periodic Inspection and Maintenance for Steam Systems	■ Generation: Boiler, dearator, feedwater tank, chemical treatment equipment, blowdown equipment, economizer, combustion air preheater, clean boiler's fireside or water-side deposits, etc. ■ Distribution: Piping, steam traps, air vents, valves, pressure reducing stations, etc. ■ End-use: Turbines, piping, heat exchangers, coils, jacketed kettles, steam traps, air vents, vacuum breakers, pressure reducing valves, etc. ■ Recovery: Piping, valves, fittings, flash tanks, condensate pumps, condensate meters, etc.
Boiler Plant Operating Practices	
Boiler Efficiency	■ Determine ratio of Btu heat absorbed by steam to Btu energy input from fuel. ■ Measure flue gas temperature, oxygen content, and carbon monoxide content. ■ Select type of excess air control (non, manual, automatic).
Heat Recovery Equipment	■ Use feedwater economizer and/or combustion air preheater. ■ Perform blowdown heat recovery.
Quality of Steam	■ Monitor boiler output to ensure "dryness" of steam.
General Boiler Operation	■ Use automatic controller for continuous blowdown. ■ Investigate common system faults (patterns of alarm signals) to determine remedies. ■ Reduce frequency of steam pressure fluctuations beyond +/- 10 percent of boiler operating pressure.
Steam Distribution, End Use, & Recovery Operating Practices	
Minimize Steam Flow Through PRVs	■ Analyze pressure reduction options: none, use boiler controls or PRVs, use backpressure turbines.
Recover & Utilize Available Condensate	■ Maximize volume of condensate recovered and utilized.
Use High Pressure Condensate to Make Low Pressure Steam	■ Maximize volume of flash steam recovered and utilized.

condensate control, insulation and refractory, and leak repair all ensure that the thermal transfer of steam is maximized. If any of these functions are compromised, the ensuing thermal loss usually requires more fuel to compensate. That, of course, means additional operating costs. Finally, as fuel consumption increases, so do combustion emissions and the liabilities associated with them.

More intensive operations and maintenance will cause certain steam plant O&M[4] costs to rise. The steam champion understands that over the boiler's lifetime, expenditures for fuel alone will dwarf other costs as well as the capital outlay for the boiler itself. The rise in incidental O&M costs expended to optimize the steam system can be more than compensated by fuel cost savings.

System optimization is an ongoing process. Continuous improvement, or judiciously maintained optimization, is the rule. Many plant managers make the mistake of implementing a one-time, comprehensive system improvement, only to let the efficiency gains erode over time through inattentive maintenance.

Table 2 (see previous page) offers the monitoring and maintenance duties on the steam champion's operations management checklist.

Personnel Management

It is immediately evident that the duties demanded by the operations management program will make intensive use of well-trained, motivated, and disciplined manpower. Plant technicians will need to apply mechanical as well as record-keeping skills. The steam champion must ensure that staff are adequately trained to understand the "big picture," i.e., the steam load's relationship to process demands. But equally important is the knowledge needed to monitor and remedy operating features of the steam system itself. In addition to training, the steam champion will be tasked with designing and scheduling a monitoring and maintenance routine. This routine will facilitate the planning of staffing levels and man-hours to be applied. In addition, it helps the steam champion to better plan the purchase of consumables related to operations needs.

Motivation is key to staff serving effectively. While it is critical for staff to understand the purpose and means of achieving plant optimization, the motivation to carry out the necessary operations routine will be enhanced if staff also share in the savings that optimization provides. Rewards also create the incentive for staff to look for improvement opportunities above and beyond the scheduled operations duties.

Training is the prerequisite to effective staffing. The steam champion seeks training resources and organizes a training regimen that develops each staff member in stages. Initial training introduces basic operational concepts and safety. Intermediate training is intended for staff with some operational experience who are prepared to improve their range of technical abilities. Advanced training presents the use of industry standards and benchmarks, introduces operating liabilities related to resource management and emissions control, and perhaps the fundamentals of human resource management.

The steam champion also has his or her own training agenda. Business principles are important, while new technology development, energy market functions, and regulatory policies are worthy of repeat study.

Membership in a professional engineering society is a worthwhile commitment for key staff as well as the steam champion. These societies have excellent resources for training and development. The provision of such membership and its perquisites is also a way to reward staff.

Training culminates in the ability to fully realize the goals of an operations program. The result—the ongoing optimization of the steam system—provides savings that accrue to the plant's bottom line.

Business Management

Steam production is ultimately conducted for business purposes. The steam champion's business management agenda is two-fold: contribute to

[4] "O&M" refers to operations and maintenance costs, which are routine or at least clearly driven by hours of operation or volume of production. O&M costs typically include labor and consumables such as cleaning supplies, uniforms, lubricants, space heat and lighting, and communication and documentation expenses.

plant output while demonstrating steam's contribution in meaningful business terms. Success on both counts will get the attention of upper management, who will ultimately decide how much financial and material support are available to steam operations.

The advent of submetering technologies helps the steam champion to track steam's contribution to different process lines within a plant. That metering data is a primary input for demonstrating business results.

Why do operations data need to be translated into business terms? Unfortunately, few chief executive or finance officers have an understanding or interest in the engineering functions and measurements that define operations management. It is usually a waste of everyone's time if a plant manager describes steam optimization impacts in terms of Btus, pounds per hour, or efficiency ratios. Meaningful communication describes impacts in terms of increases in net income, return on assets, and addition to shareholder equity. The steam champion discusses the impact of steam optimization in these terms.

Central to business dialog is the improvement of net income, or the "bottom line." All other financial impacts depend on this measure. The preceding discussion of system operations management describes how optimization reduces fuel expenditures. Those expense savings translate directly into new income. A thorough discussion of steam system efficiency's financial impacts, with examples, is already available (Russell 2000). The following is a select review of the financial impacts of steam optimization.

Return on assets (ROA). As a financial variable, ROA is simply the ratio of net income for an accounting period to the average value of plant assets in place for that period. A corporate decision-maker uses ROA as a measure of how hard assets work. To illustrate, consider two plants, both with $10 million in assets. One produces an annual income of $1 million (a 10 percent ROA), while the other produces $2 million (20 percent ROA). This is clearly a difference worthy of investigation.

Production cost per unit. Competition in some industries forces managers to focus on cost. This is especially true for high-volume, commodity processes such as refining, primary chemicals, and pulp and paper production. The marketplace usually dictates prices; profitability will then depend on cost containment. A steam champion is prepared to document and communicate the results of optimization in terms of a reduction in cost per unit of product. The corporate audience often responds better to this measure than to a statement of aggregate costs saved. Sometimes, a few pennies saved in the per-unit production cost have a meaningful impact on the product's marketability. A steam champion can identify the increment of per-unit cost savings attributable to steam optimization.

Addition to shareholder equity. The holding companies that own manufacturing concerns are keenly interested in the performance of their stock, as well as in the opinions of that stock as issued by Wall Street analysts. Accordingly, company executives place a priority on the company's performance in terms of the variables tracked by equity analysts.[5] The holding company's cumulative goal, however, is to grow shareholder equity. The steam champion can translate an improvement in net income into incremental growth in equity. For example, assume that a holding company stock sells at a price of ten times earnings.[6] If a steam optimization initiative realizes $1 million in savings, shareholder wealth is increased by an increment of $10 million ($1 million times the P-E ratio of 10).

The steam champion serves his or her own interests in contributing to the firm's financial and corporate priorities. Steam managers compete with process and other managers for a share of the firm's capital budget. Those managers who can demonstrate superior returns on their capital investment proposals will get greater corporate support.

Planning

As implied by the previous discussion, the industrial steam plant manager's agenda encompasses

[5] Some examples of financial variables tracked by equity analysts include inventory turnover, debt ratios, profit margins on sales, and rates of retun on assets. Many other creative variables exist.

[6] Stated alternatively, the stock's P-E ratio is 10.

more than mechanical concerns. Regulation, human resource considerations, and technology evolution impact steam management to varying degrees over time. The steam champion monitors these forces and makes plans for accommodating change.

Emissions control. These regulations impact most large-scale combustion processes. Current output restrictions limit sulfur dioxide and nitrous oxides. Emerging legislation in response to global warming concerns will focus on carbon emissions. Industrial steam managers must contain emissions output with alternative fuel selections, proper combustion techniques, and abatement technologies. The acceptable thresholds for emissions production are subject to constant revision. Professional and industry associations have excellent resources for interpreting U.S. Environmental Protection Agency regulations as well as the technologies and practices that facilitate compliance.[7] The steam champion uses these resources to adjust the operations management plan accordingly.

Professional certifications. Safety and emissions regulations shape the personnel certification requirements for steam system operations. The cost of acquiring certifications, as well as the cost of compensation required by properly certified personnel, is a challenge for human resource management. Under-trained apprentices are easier on the payroll, but a corresponding loss in productivity is the trade-off. It is desirable to develop these personnel, assuming they can be retained after completing their training. The steam champion has tough choices for sustaining acceptable levels of certified labor. Depending on labor market conditions and the plant manager's tolerance for continuous hiring and staff development, the choice is between outsourcing operations to a certified energy performance contractor, or managing a staff with a few key professionals and a complement of apprentices who essentially learn on the job. In the best of circumstances, the steam champion can plan staffing needs in response to statutory certification requirements. But in practice, this human resource challenge may defy planning. The steam champion will need executive-level commitment to training and compensation as the means for attaining system optimization.

Technology evolution. New technologies are in part relevant to the preceding discussions about emissions control and professional certification. But technology development is also relevant to plant and process design. Certain control, monitoring, and automation technologies are emerging that will boost the productivity of steam systems. Other technologies emerge as substitutes for steam. The steam champion monitors development on both these fronts and uses this knowledge to influence asset selection for the plant.

Monitoring technologies rely on data flows over time to determine a steam system's operating norms. Monitoring reports warn the operator when a data snapshot captures operating results out of the ordinary. Boiler operations, distribution elements, and end-use applications can all be monitored in this fashion. Automation technologies perform a variety of functions, from signaling the failure of key hardware components to controlling the mixture of fuels used simultaneously for combustion. The steam champion monitors the implementation of these innovations and employs them to the extent that such technologies are compatible with available human resources. To elaborate, it is theoretically possible to monitor every component of a steam system; this could be a problem if there is insufficient staff to interpret all the data that the monitors generate.

New technologies also bring substitutes to steam. Infrared applications, both electric and natural gas fired, have supplanted steam in the drying of paper coatings in some plants. Sonic vibrators, in combination with membrane sifters, are emerging as a non-thermal method for distilling liquids. Countless electric applications have been devised to provide thermal energy with pin-point accuracy in product fabrication processes.

The steam champion monitors technology developments for those that are relevant to his or her industry. In some instances, steam champions may determine that a substitute technology is ultimately superior to steam. The true criteria in making such a choice is the degree to which a technology option will add value—either through cost

[7] The American Gas Association and the American Petroleum Institute are two good examples.

reduction or product enhancement. Steam champions in certain industries or facilities may have to evolve professionally with the prevailing technology. But in the industries featuring large scale, continuous thermal energy, steam is not unlikely to be supplanted. The need for steam champions to support these systems will continue for the foreseeable future.

Conclusion

The fundamental premise of steam system optimization is that some investment of resources is required to accomplish fuel savings. Projects to be implemented will be those with the most attractive savings and return on investment. Manufacturers that choose to pursue optimization will have (1) a sufficient time horizon to realize benefits that are especially large in the long term, and (2) top level executive commitment to achieving optimization goals. In short, the appropriate corporate culture is a prerequisite for allowing a steam champion to emerge and thrive.

Steam champions already exist, serving their employers and perhaps entire industries with their expertise. Many are senior, which is not surprising given the volume of expertise they have amassed. But by the same token, senior champions eventually retire, and replacements are not always available. Energy policy, as well as industry leaders at the trade association level, might want to support the development of new steam champions. The steam champion management agenda—performance, operations, personnel, business, and planning—is one that needs adequate support from the training community.

Given industry's appetite for energy, as well as the energy supply concerns that are resurfacing in 2001, the rationale for developing and retaining steam champions is compelling. The business impacts of doing so should be all the incentive needed for industry to act accordingly.

For more information contact:

Christopher Rusell
Alliance to Save Energy
Email: crussell@ase.org
Phone: (202) 530-2225

Dr. Anthony Wright
Oak Ridge National Laboratory
Email: alw@ornl.gov
Phone: (865) 574-6878

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For additional information on BestPractices Steam, contact:

FRED HART
Office of Industrial Technologies
U.S. Department of Energy
202 586-1496

CHRISTOPHER RUSSELL
Senior Program Manager for Industry
The Alliance to Save Energy
202 530-2225

Visit the OIT Steam Web site at:
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Fax: (360) 586-8303
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Energy Efficiency and Renewable Energy
U.S. Department of Energy
Washington, D.C. 20585

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