Industrial Technologies Program

# Steam Digest

## *Volume IV*

A compendium of articles from 2003 on the technical and financial benefits of steam efficiency, presented by stakeholders in the U.S. Department of Energy's BestPractices Steam efforts


Compiled for the

**Industrial Technologies Program**

By the

**Alliance to Save Energy**

ALLIANCE TO SAVE ENERGY

*Creating an Energy-Efficient World*



U.S. Department of Energy

**Energy Efficiency and Renewable Energy**

Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

# Acknowledgements

The *Steam Digest: Volume IV* is the fourth annual compilation of articles dedicated to steam system efficiency. The U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy sponsors the BestPractices Steam program, which either directly or indirectly facilitated the creation of all the articles contained in this volume. BestPractices Steam, which is part of the wider BestPractices program under DOE's Industrial Technologies Program, works with industry to identify plant-wide opportunities for energy savings and process efficiency.

The BestPractices Steam Steering Committee provides a great deal of input and guidance into the program (see more information about the Committee on pages 1 and 2). **Mr. Fred Fendt,** Technical Fellow with Rohm & Haas, serves as Chair of the BestPractices Steam Steering Committee. **Ms. Debbie Bloom,** Senior Consultant for Nalco Company, continues as Vice-Chair. **Mr. Doug Riley,** Director of Global Energy of Millennium Chemicals, serves as the Executive At-Large. These individuals participate on the BestPractices Steam Steering Committee:

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President, Council of Industrial Boiler Owners

**Victor Bogosian**
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Both **Mr. Buddy Garland,** Director of the DOE Industrial Technologies Program, and **Mr. Peter Salmon-Cox,** BestPractices Team Leader, provide oversight to the BestPractices Steam program and ensure that the program fits in with national industrial energy efficiency goals.

In January 2004, **Dr. Robert (Bob) Gemmer**, who joins us from DOE's BestPractices Process Heating in the Industrial Technologies Program, took over BestPractices Steam and will be overseeing both activities. He served as a member of the BestPractices Steam Steering Committee when he was employed by the Gas Research Institute. Since the program's inception and until January 2004 when he officially retired, **Mr. Fred Hart** of DOE's Industrial Technologies Program led BestPractices Steam. Under Mr. Hart's leadership, the program developed scores of tools and resources, such as *Steam Digest*, and helped plant managers nationwide improve the efficiency of steam operations at their plants.

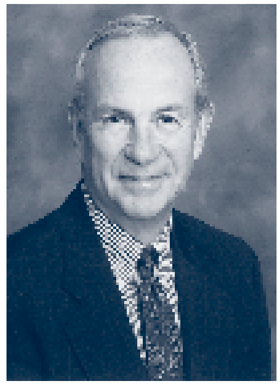
The Alliance to Save Energy (Alliance) is a nonprofit coalition of prominent business, government, environmental, and consumer leaders who promote the efficient and clean use of energy worldwide to benefit the environment, the economy, and national security. The Alliance conducts industrial outreach on behalf of the program, making sure that program materials are properly distributed among state energy programs, utilities, trade associations, industry media, and the Internet. The Alliance plays a major role in compiling this document every year.

**Dr. Anthony Wright,** Senior Technical Staff at Oak Ridge National Laboratory, continues to direct the evolution of the program's technical content. **Mr. Christopher Russell,** Director of the Industry Sector at the Alliance, provides program guidance and contributes research on steam efficiency's managerial impacts. **Ms. Kristin Lohfeld,** Industrial Program Manager at the Alliance leads the program's outreach and marketing efforts. **Mr. Adam Hudson,** Industrial Program Associate at the Alliance, provides additional program support.

We offer grateful recognition to each author for his or her contribution to this compendium. Special thanks go to **Ms. Michelle Sosa-Mallory** of National Renewable Energy Laboratory and her staff for assisting with the publication of this volume.

# Dedication

William W. Pitkin
1936 to 2003



We are saddened by the loss of William (Bill) W. Pitkin, who died June 11, 2003, at his home in Annapolis, Maryland. Bill was the first and longest-serving Chairman of the BestPractices Steam Steering Committee, a capacity he filled from 1998 to 2001. This commitment was in addition to his professional duties as the Executive Vice President of the National Insulation Association (NIA), a role he retired from in 2002, after 19 years of service.

Bill was a tireless supporter of steam efficiency and the BestPractices Steam program. Bill had the ability to work easily and effectively with top-level policy officials as well as junior support staff, and he left lasting impressions on all of us. Prior to his work for the NIA, Bill was a District Sales Manager for Owens Corning and the Vice President of Marketing and Sales for Certainteed Corporation. He received his high school diploma from Choate Rosemary Hall, where he was class president; and his Bachelor of Arts degree from Stanford University, where he played varsity football. He served in the U.S. Army for 2 years after graduating from Stanford.

He was an avid sailor and a past president of the Saefern Community, where he served as Chairman of the Lakes and Grounds Committee. He is survived by his wife of 30 years, Susan C. Pitkin, four children, ten grandchildren, and three great-grandchildren.

This volume of *Steam Digest* is dedicated in his memory.

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## Steam Efficiency Experts at Your Fingertips: An Introduction to the BestPractices Steam Steering Committee

*Christopher Russell*
*Kristin Lohfeld*
*Alliance to Save Energy*

Industry depends on steam systems for achieving a wide variety and volume of manufacturing tasks. Despite the fact that about 45% of industry's energy consumption is directed to boiler rooms, steam management is often a neglected discipline. To address this oversight, and to boost industrial competitiveness through better resource management, the U.S. Department of Energy (DOE) sponsors the BestPractices Steam program.

The Alliance to Save Energy conceived this program, which was launched in collaboration with DOE in 1998 as the "Steam Challenge." Modeled on the DOE Motor Challenge program, this steam initiative gathered industry experts in a steering committee. That group continues to provide guidance and oversight to DOE in developing actionable steam diagnostic and reference resources for industrial plant managers.

The **BestPractices Steam Steering Committee** currently consists of 46 volunteers, including industrial steam end users, steam solution providers, trade associations, national laboratories, educational institutions, Federal and local government representatives, and non-profit organizations. Staff support is provided by DOE, Oak Ridge National Laboratory, and the Alliance to Save Energy. This staff, along with the steering committee of volunteer experts, ensures the development of steam resources that are non-biased, rigorously formulated, and responsive to industry needs.

The steering committee meets twice a year to brainstorm on steam efficiency needs in the marketplace, plan future training and outreach events, develop new technical tools, enhance

*Table 1. Top 10 BestPractices Documents/Software Downloads*

| Document/Program | Number of Downloads<br>*www.oit.doe.gov/bestpractices*<br>October 2002 to August 2003 |
|---|---|
| **1.** Improving Steam System Performance: A Sourcebook for Industry | 57,569 |
| **2.** Steam System Survey Guide | 56,630 |
| **3.** CIBO Energy Efficiency Handbook | 42,617 |
| **4.** Guide to Low-Emission Boiler and Combustion Equipment Selection | 31,807 |
| **5.** United States Industrial Electric Motor Systems Market Opportunities Assessment | 28,625 |
| **6.** Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industries | 28,140 |
| **7.** Fact Sheet: Reducing Power Factor Cost | 21,591 |
| **8.** Fact Sheet: Determining Electric Motor Load and Efficiency | 19,982 |
| **9.** Improving Pumping System Performance: A Sourcebook for Industry | 19,317 |
| **10.** Assessment of the Market for Compressed Air Efficiency Services | 19,210 |
| **Total BestPractices Steam Downloads (in the top 10)** | **216,763** |
| **Total BestPractices Downloads (all downloads)** | **1,044,491** |
| **BestPractices Steam Downloads as percent of total** | **20.7%** |

existing resources, and report success stories back to DOE. Distinct agendas are assigned to each of its four subcommittees: BestPractices and Technical, Marketing and Business Communications, Training, and Program Evaluation and Policy.

The **BestPractices and Technical Subcommittee** developed the steam-related resources available through DOE's Web site. These resources are some of the most popular downloads of all DOE BestPractices program resources. More than 20% of these downloads were steam-related. Listed in Table 1 are the top 10 files/programs downloaded from October 2002 through August 2003.

**Marketing and Business Communications Subcommittee** activities include workshops, conferences, and publications. To showcase the best in professional steam literature, the Alliance to Save Energy puts together this annual *Steam Digest* compendium. These articles include steam facility case studies, benchmarking projects done through steam assessments, diagnostic software resources, outsourcing trends, and program resources developed by DOE. Readers will notice that many *Steam Digest* authors are also on the steering committee. To request of copy of the publication on CD-ROM, contact the EERE Information Center at 1-877-337-3463 (1-877-EERE-INF).

Many steering committee members are featured speakers at the Alliance's "Optimizing Steam System Performance" awareness workshops held throughout the United States. In 2003, the Alliance sponsored 14 workshops reaching more than 650 individuals and 280 companies. Speakers cover topics such as best practices in steam distribution, optimizing condensate return systems and water treatment, combined heat and power applications, return on investment from training, business impacts of steam efficiency, and industrial case studies. One of the key features is the steam software tool demonstration where attendees learn how to use the Steam System Assessment Tool. With the steering committee's participation and valuable information to share, more industrial and institutional steam users are making steam efficiency projects happen. According to the workshop attendees, more than 80% planned to implement a project using the information provided at the workshops.

In 2003, the **Training Subcommittee** inaugurated the Steam Qualified Specialist training, which is designed for steam service providers who are interested in becoming proficient in using the BestPractices Steam software tools. Steering committee members provided valuable feedback throughout the process—from assisting with course design to participating in the trial training process. See *www.oit.doe.gov/bestpractices/software/steam_by_name.shtml* for a list of DOE Steam Qualified Specialists. To find out when the next Qualified Specialist training or other events will occur, visit *www.ase.org/steamingahead/calendars/*.

The **Program Evaluation and Public Policy Subcommittee** ensures the overall effectiveness of the BestPractices Steam initiative through developing and applying key metrics. The subcommittee also identifies and evaluates public policy needs that would increase awareness and encourage actions by industry to improve steam efficiency.

# Steam Partnerships: Case Study of Improved Energy Efficiency

*Michael V. Calogero*
*Robert E. Hess*
*Novi Leigh*
*Armstrong Service, Inc.*

Effective energy management involves expertise in three core areas: commodity supply, generation (production), and distribution/utilization. Historically, energy providers have only been partially successful in fulfilling the needs of industrial energy consumers. They have supplied the energy commodities (fuel, electricity, or water) and may have even assisted with energy (steam) generation and production. But in most cases, their assistance and expertise came up short when dealing with the distribution and utilization of energy within the facility, particularly when addressing steam-based energy systems. (See Figure 1.) The fully integrated approach to energy management requires proven experience in the optimization of steam distribution and utilization, areas where the highest percentage of utility costs are variable.

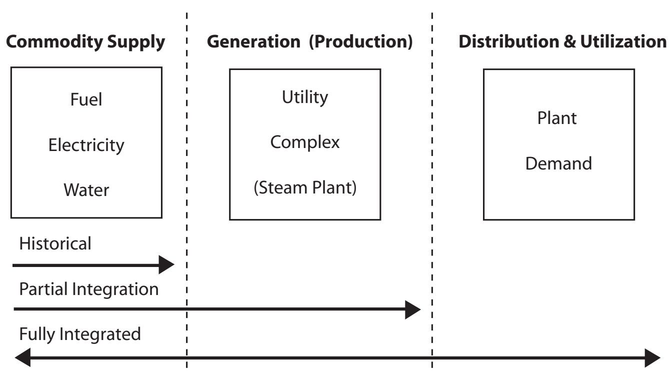


*Figure 1. Degree of energy management integration.*

A unique energy services alliance was recently structured and implemented with one of the largest health care linen service facilities in southern New York. The existing power plant was acquired from the client and upgraded. An extensive discovery-engineering audit was performed to identify major improvements that were subsequently made to the site utility systems. Particular emphasis was placed on the steam system, with most of the first phase optimization work directed at improving the distribution and utilization of steam energy.

Overall, this "steam partnership" captured a 17% average reduction in energy usage through the implementation of six energy savings projects. Outsourcing this activity allowed the client to refocus capital and internal resources on growing the core linen services business. To ensure continued interest by both parties over the 10-year agreement, a unique billing formula was structured that indexes total utility costs against laundry processed by the facility and provides incentives for both parties to drive down energy usage over the long term.

The responsibility for managing and tracking the supply of energy commodities was also transferred from the client. This integrated approach combines all three energy areas (supply, generation and distribution) under a single optimization entity. This paper describes the subject facility and the savings projects that were implemented. The results are summarized in a graph that shows an index of energy usage to laundry processed and compares a baseline period to actual performance after project implementation.

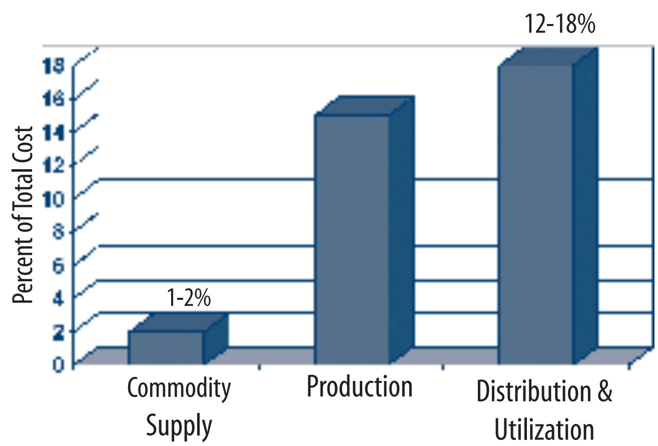


*Figure 2. Controllable utility cost variances—steam generating complex.*

In a light industrial steam generating complex, the highest percentage of variable controllable costs are found in the distribution and utilization areas. Typically, 12% to 18% of the as-found costs are variable and subject to optimization. This compares to 10% to 15% of the generation or steam production costs, and only about 1% to 2% of the commodity supply. (See Figure 2.) For this reason, most of the company's initial optimization efforts are focused on identifying and implementing savings opportunities in the plant distribution and utilization systems.

The first step in the optimization process was a site-wide, discovery-engineering visit to interview employees, observe operations, and record plant operating data.

## Overview of the Laundry Processing and Steam Systems

The subject laundry facility processes about 120,000 pounds of institutional linen per week. The operations include multiple washing, drying, pressing, ironing, and dry cleaning processes.

The washing process takes place in Lavatec machines. In these tunnel washers, the linens go through a number of compartments. Each compartment requires a certain washing temperature. This is achieved by supplying softened water to the machine and heating it within the machine by direct injection of steam at 115 pounds per square-inch gauge (psig). Of the 11 compartments, four are supplied with direct steam injection to obtain the required temperatures of 140˚F to 165˚F. Several hot water tanks at the bottom of the machines store water at 95˚F. The hot water stored in these tanks is partly recycled water from the tunnel machine.

Next to the tunnel machines are the tunnel dryers. These dryers burn gas as the heating source. There are also tumble dryers that utilize steam to heat incoming air.

The ironing process, which takes place in ironers, uses a heated bedplate over which large metal cylinders revolve. These cylinders are covered in an absorbent material known as roller clothing. The linen passes between each steam-heated surface and roll. When the linen is passed from the last heated bedplate/roll, it should be dry, ironed and free of creases, and ready to fold. Garment presses are used to dry and iron individual garments. All of the processes and irons are fed steam even when temporarily idle, so effective condensate removal is very important.

### *Steam Generating System*

The facility operates one of its two Cleaver Brooks boilers to meet its steam demand. The main boiler is the newer one (manufactured in 1986) with a rated capacity of 300 horsepower (HP), or about 10,600 pounds of steam per hour at maximum pressure of 150 psig.

The boiler operates about 12 hours a day, for 6 days per week. During the weekends in winter, the boiler needs to be turned on for about 4 hours to prevent freezing the pipelines. (We expect that increased heat retention after the insulation project will eliminate this need in the future.)

The boiler generates steam at 115 psig. There is no steam flow meter in the facility. However, from the boiler stack measurement and the gas bills, an approximate load of the boiler was obtained. Based on our measurements, the oxygen level in the stack gas was 5.8% and the stack temperature was 324˚F. Our evaluation showed that the boiler operates at an efficiency of 83.9%.

The boilers and dryers use natural gas. The boiler gas consumption is not separately metered; calculations indicate that 80% of the total gas is utilized in the boiler. Based on the gas consumption and the boiler efficiency, the average boiler load was 4,700 pounds per hour, or 44% of its rated capacity.

The facility performs intermittent boiler blowdown on a regular basis. Based on several water analysis results, the average boiler blowdown was only 2.2%. The analysis also showed that the boiler water conductivity was very high because of the low blowdown rate. The highest conductivity measured was 7,100 micromhos[1] versus a 4,000-micromho target.

There is no deaerating process as part of the boiler treatment. Instead, chemicals are injected into the condensate tank and the boiler. An inspection of the main boiler showed internal scale formation attributed to chemical treatment fluctuations and insufficient blowdown.

### *Steam Utilization*

The laundry facility utilizes steam at 115 psig. The steam users are the Lavatec washing machines, drying, pressing and ironing machines, dry clean facilities, unit heaters, and radiators. As stated earlier, the Lavatec washing machines have a direct steam injection system.

### *Condensate Return System*

Condensate is returned to a horizontal cylindrical condensate tank that is located in the basement where it mixes with softened make-up water. Two electric-driven pumps transfer the boiler feedwater to the boiler.

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[1] A measure of conductivity. 1/ohm = 1 micromho

The condensate tank was venting flash steam to the atmosphere at a significant rate. Pressure gauges are installed in a few places along the condensate lines, most of which indicated 25 psig. Those in the laundry room and dry cleaning room showed between 7 to 12 psig. The high condensate pressure was caused by several failed steam traps passing live steam.

There is no meter to indicate the quantity of returned condensate. However, water analyses were used to estimate the percentage of returned condensate to the boiler house. Based on the conductivity analysis, the returned condensate was 55% of the total boiler feedwater.

### *Water Treatment*

The facility uses city water in the softener to get better quality laundry and boiler feedwater. The softened water is also used in the Lavatec washing machines. A make-up water meter is available in the line that goes to the condensate tank.

Annual steam generating cost was estimated from the utility bills. Table 1 is a summary of the various steam-related costs. The steam generation cost does not include the cost of gas used in the dryers.

Presently, the facility pays for the same quantity of sewage water and raw water purchased. In the future, we will investigate reducing the sewerage cost by metering the sewer flow back to the city and requesting a credit for evaporation losses. Based on a plant study, evaporation at the dryers and irons is projected to reduce the measured sewerage flow by 35%.

*Table 1. Various Steam-Related Costs (1999 Baseline)*

| | |
|---|---|
| **Gas Cost** | $4.12/MMBtu* |
| **Heat Cost** | $4.90/MMBtu |
| **Water Cost** | $0.90/M lbs** |
| **Treated Water Cost** | $1.44/M lbs |
| **Steam Cost** | $6.98/M lbs |
| **Condensate Cost** | $2.54/M lbs |

* $/MMBtu = Dollars per million British thermal units
**$/M lbs = Dollars per thousand pounds

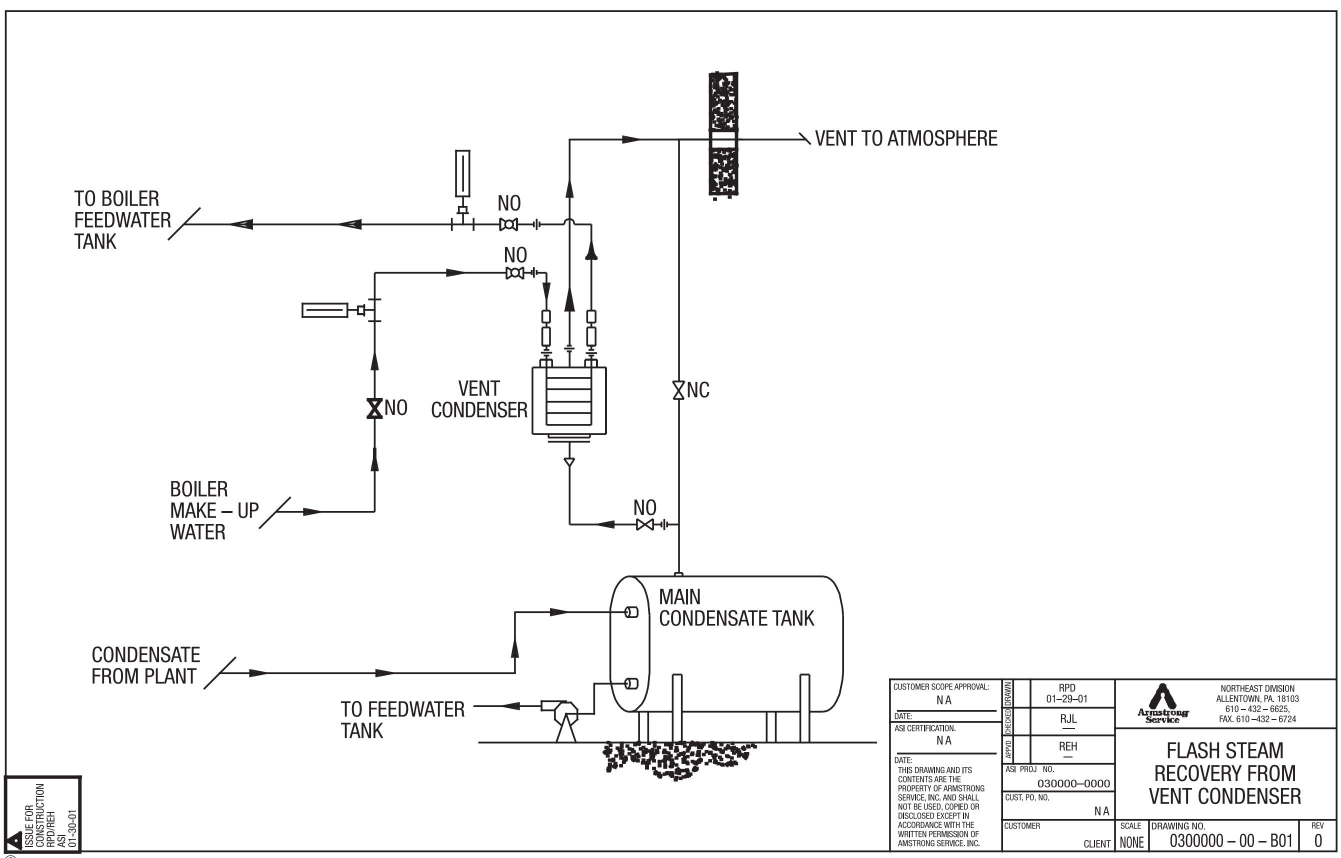



*Figure 3. Vent condenser installation.*

## Saving Opportunities

A thorough review confirmed there are energy savings opportunities in the boiler system, steam distribution system and condensate return system. The following is a summary of the initial six projects that were implemented after the multi-year agreement was executed.

1. **Replace all identified defective steam traps.** There were 80 steam traps at the facility. During the comprehensive survey, 16% of the traps were blowing through. This resulted in an annual steam loss of 2.4 million pounds of steam.
2. **Repair live steam and condensate leaks.** The identified steam and condensate leaks accounted for 6.1% of the total steam generation. These leaks, including five isolation valves in the boiler room, were tagged and subsequently repaired.
3. **Improve steam quality to processing areas.** After analyzing complaints from plant employees about steam wetness, a major redesign of the main steam distribution system was made to improve the quality (dryness) of the steam exiting the boiler room. In addition, the steam supply and condensate return loops in the subject areas were also upgraded.
4. **Recover vented flash steam.** The condensate tank is vented to the atmosphere. A high quantity of vented steam is caused by the high-pressure condensate that is discharged at the lower pressure. This causes about 9% of the high-pressure condensate to be flashed. A system was designed to capture the flash steam energy by pre-heating boiler make-up water in a vent condenser. In addition to the heat savings, higher make-up water temperature improves the effectiveness of chemical treatment in the condensate tank. Figure 3 (previous page) illustrates the arrangement of the vent condenser installation.
5. **Insulate bare hot surfaces.** During the audit, we observed pipelines carrying either steam or hot condensate that were not insulated or poorly insulated. The condensate tank and some other hot surfaces, such as flanges and valve bodies, were not insulated. For safety reasons and to prevent excessive heat loss by radiation, hot surfaces must have effective insulation.

   The basic function of insulation is to retard the flow of unwanted heat transfer. Where justified, condensate lines were also insulated to capture the maximum heat that can be returned to the boiler plant for additional savings.
6. **Shut-off chemical treatment system when boiler is down.** There are two chemical pumps, each of which feeds chemicals to the condensate tank and the boiler. The boiler operates about 12 hours per day, 6 days per week. During the audit, we noticed that when the boiler was down, the chemical injection pumps were still on. After analysis and consultation with the chemical treatment supplier, we proposed to automatically shut off the chemical pumps when the boiler is down. This will save chemicals and water, and reduce heat losses because of less blowdown. Wide variations in boiler water conductivity would also be eliminated by this project.

## Results

The identified savings projects were designed and implemented at the laundry facility. The impact of these projects is reflected in a plot of the gas utilization (decatherms of natural gas [DTH]) divided by thousands of pounds of processed laundry (PTS). In Figure 4, the lower curves represent the period after the projects were completed and are compared to a baseline period labeled 1999.

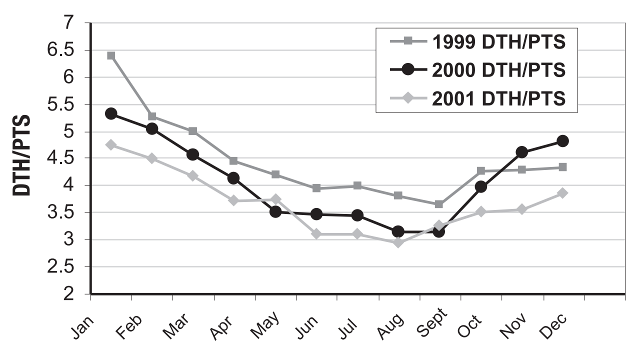


*Figure 4. Gas utilization 1999 to 2001.*

The overall result is an average reduction in the gas utilization of 17% over the baseline year.

For example, in the period labeled September, the gas utilization after optimization was 3.0 decatherms/thousand pounds (DTH/PTS) compared to a baseline index of 3.6 DTH/PTS. This represents a reduction of 16.7%.

Figure 4 also shows the impact of plant operations and equipment service factor on the gas utilization. During November and December 2000, an unplanned maintenance event occurred that forced the plant to operate with the less efficient back-up boiler. This boiler also suffered a control problem during the run. These upsets are reflected by the gas utilization exceeding the baseline for November and December 2000 despite the optimization projects. With normal operation restored by late December, the January 2001 utilization at 4.2 DTH/PTS was 20.8% below 2000 and 34.3% below the baseline year.

In Figure 5, the total utility costs per thousand pounds of processed laundry are plotted against a baseline index that was established prior to project implementation. This baseline index is depicted by the dashed line. The area below the baseline reflects the incremental savings generated by the projects on a total utility cost basis.

For example, in June, the actual monthly rate (AMR) was \$34.50/PTS compared to a baseline of \$44.15/PTS. The net utility cost savings were \$9.65/PTS, or \$4,600 at 475 PTS in the month and 1999 baseline utility prices.

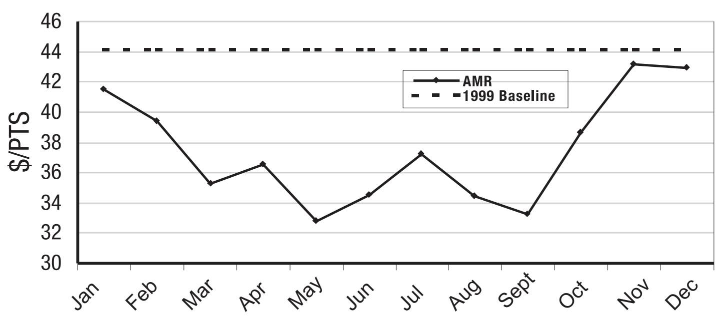


*Figure 5. Actual monthly rate (AMR) in 2000.*

## Conclusion

The fully integrated approach to energy management produced an average reduction of 17% in gas utilization and an overall savings of 14% in total gas and electricity costs for the facility. Furthermore, the structure of the multi-year agreement is such that both partners will continue to seek out energy savings in the future.

Several Phase Two projects are already being scoped out. These include:

- Changing gas consumption tracking to reduce service fees
- Metering sewer flow to receive evaporation credit
- Using non-chemical water treatment to reduce chemical treatment costs
- Installing controls and insulation upgrade of older (back-up) boiler.

## References

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2. Operating data from client's laundry processing facility from 1998 to 2001.
3. Wayne, Turner C., *Energy Management Handbook*, 2nd edition, 1993.
4. Armstrong International, Inc., *Steam Conservation Guidelines for Condensate Drainage*, Handbook N-101, 1997.
5. Forenta Systems, *Technical Piping Tips*, Bulletin TT-69, 1993.

## Strategies in Optimizing Condensate Return

*Deborah Bloom, Nalco Company*

Optimizing condensate return for reuse as boiler feedwater is often a viable means of reducing fuel costs and improving boiler system efficiency. Condensate that is contaminated with corrosive products or process chemicals, however, is ill fit for reuse; and steam or condensate that leaks from piping, valves, traps and connections cannot be recovered. According to the U.S. Department of Energy's *Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industries* report (1):

- Approximately 66% could realize typical fuel savings of 3% to 7% with an effective steam trap management program
- An estimated 6.5% could realize typical fuel savings of 2.9% by minimizing vented steam
- About 24% could realize typical fuel savings of 2% by optimizing condensate return
- Around 16% could realize typical fuel savings of 1.4% by repairing steam leaks
- Approximately 7.8% could realize typical fuel savings of 0.9% by isolating steam from unused lines.

As more condensate is returned, less make-up is required, saving on both water and make-up water treatment costs. The high purity of the condensate allows for greater boiler cycles of concentration, thus reducing water and energy losses to blowdown. The high heat content (typically in excess of 180°F) can provide substantial energy savings. Additional savings will also be noted in reduced water treatment chemicals, water, and sewer costs. Effective chemical treatment, in conjunction with mechanical system improvements, condensate polishers, and automatic dump systems can assure that condensate is safely returned and valuable energy recovered.

### Chemical Treatment

Corrosion in condensate systems can limit the quality or quantity of returned condensate because iron and copper corrosive products deposit on boiler heat transfer surfaces. This reduces heat transfer efficiency and could cause tube failure.

Condensate corrosion control is required to protect process equipment, lines, and tanks, and to maintain the condensate as a quality feedwater source. Steam/condensate system corrosion can result in increased maintenance and equipment costs, energy loss through steam leaks, and loss of process heat transfer efficiency.

Condensate corrosion is most commonly associated with carbon dioxide ($CO_2$), although the presence of oxygen and ammonia may also be a problem. The major source of $CO_2$ in steam is the breakdown of feedwater bicarbonate and carbonate alkalinity in the boiler. The liberated $CO_2$ is carried with the steam into the condensate system.

$CO_2$ is not harmful until it dissolves in condensate. As it dissolves, it forms carbonic acid. Since condensate is extremely pure, even small quantities of carbonic acid can significantly lower condensate pH and increase its corrosivity. Corrosion rates increase as temperatures increase. Because condensate is hot, this causes it to be even more aggressive to metal surfaces.

Volatile neutralizing amines, such as cyclohexylamine, morpholine, and diethylaminoethanol, are typically used to neutralize carbonic acid and raise the condensate pH. These programs are most effective when fed to maintain a minimum pH of 8.5, ideally 8.8 to 9.2 (Figure 1). A blend of several amines will assure that corrosion protection is distributed throughout the entire steam/condensate system. Filming amines and a new, patented non-nitrogen based chemistry (Nalco ACT®) are alternative condensate treatments.

### System Design and Maintenance

Steam/condensate system design and maintenance not only affect the delivery of quality steam, but also the ability to remove condensate from the system. Poor drainage of condensate can result in corrosion, erosion, and water hammer, all of which will eventually result in leaks and failures and limit the amount of condensate returned for reuse as boiler feedwater.

It is not within the scope of this article to thoroughly discuss all the design issues that might affect a plant's ability to return condensate.

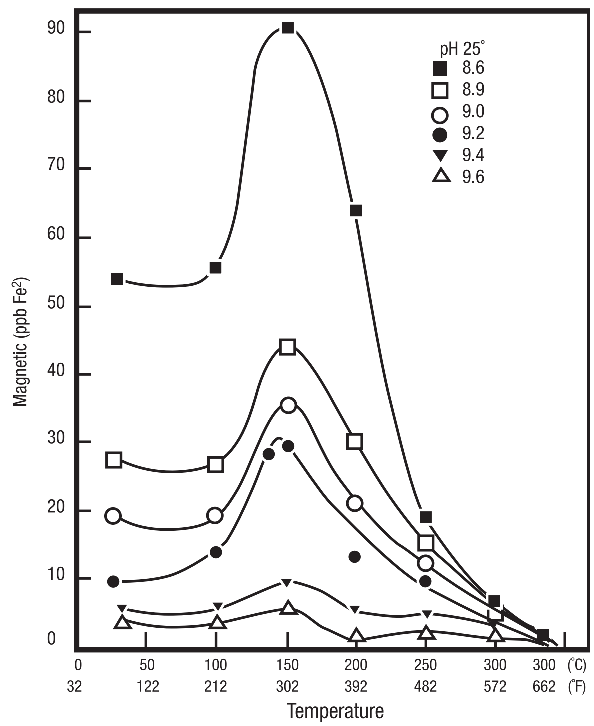


*Figure 1. Solubility of magnetite in water (2).*

However, common good engineering practices are listed below, as defined in DOE's *Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industries* (1).

- Supply dry, high-quality steam. Steam quality must generally match process requirements and be of sufficient quality (dryness) not to erode system components. In those instances when high-moisture steam is used, a steam separator should be considered. Supply lines should also be insulated and trapped to prevent accumulation of condensate.
- Isolate steam from unused lines with properly located isolation valves. Any dead leg open to steam should be trapped to prevent condensate accumulation.
- Make sure lines and traps are properly sized. This minimizes pressure loss, erosion, heat loss, and blow-through steam. Horizontal lines should be sloped at 1 inch per 10 feet, in the direction of flow and properly supported to prevent sagging and condensate accumulation.
- Install sufficient traps on steam mains to remove condensate as quickly as possible. At a minimum, traps should be located on all vertical risers upstream of control valves, and at 100- to 300-foot intervals along horizontal runs of pipe.
- Use the correct trap for the application. Never group trap. Group trapping invariably leads to back-up of condensate in the system.
- Ensure that piping allows the condensate to be removed effectively. Coils should be fitted with a vacuum breaker to allow condensate to drain freely. Waterlogged equipment not only fails to operate as expected, but also is prone to corrosion and water hammer.
- When possible, avoid any increase in elevation on return condensate lines. Condensate that is evacuated to a higher elevation does not flow by gravity. It requires a pressure slightly greater than the head pressure resulting from the elevation rise. When elevation of condensate after a trap is necessary, a pumping trap may be necessary to ensure good drainage.
- Install receiver vents of the proper size. Receiver vent lines that are too small restrict the loss of flash steam. This, in turn, results in hotter condensate return temperatures and potential problems with cavitation of electric condensate return pumps. Alternatively, use pressure-powered pumps.
- Make sure condensate return lines are sized to move the flash and blow-through steam present after a trap, as well as the condensate. Steam (vapor) is more voluminous than condensate (liquid). Condensate piping that is sized only for liquid is grossly undersized.
- Choose materials of construction that will minimize corrosion.

## Minimizing the Effect of Contaminated Condensate

### *Condensate Polishers*

Polishing units can be used to minimize the effect of contaminated condensate so it can be reused as boiler feedwater. A variety of polishing equipment is available for the removal of contaminants from condensate. The type of polishing equipment selected depends on the contaminant and quantity to be removed, and also on the water chemistry requirements of the boiler system.

Most polishers rely on some sort of ion-exchange technology, which replaces the contaminant with a less objectionable species. Ion-exchange units also serve as filters of suspended particulates, typically metal oxides. Simple mechanical filters with appropriate pore size, electromagnetic filters, or activated carbon filters may also be used, depending on the contaminant that is to be removed. Table 1 provides a simple comparison of some common polisher types. It is important to remember that no process is 100% efficient. However, even with a condensate polisher in line, some amount of contaminant will likely make it through to the feedwater.

### *Automatic Dump Systems*

Another means of minimizing the effect of contaminated condensate is to sewer it before it returns or reaches the polishers. Depending on the degree of contamination, this is often a prudent action. Badly contaminated condensate may quickly exhaust or foul polishers, allowing the full amount of contamination to return to the feedwater system.

Automatic dump systems must be installed properly to be effective at detecting and sewering condensate that is unfit for reuse. Velocities in pumped returns are commonly 6 to 8 feet per second (ft/sec) (3). Automatic control valves can take 4 to 5 seconds to actuate, close, and divert the condensate to sewer. This means there must be a minimum of 24 to 40 feet between the detection device and the valve if all contamination is to be prevented.

Most detection devices will require additional response time since they often need a cooled sample and are not located immediately on the return condensate line. Sample line size (diameter and wall thickness), length, and volume will determine how much additional response time this adds. Table 2 shows the minimum time in seconds per linear foot required for a sample to travel to the detection device. Additional time is required for the contaminant to rise to the alarm concentration. There may also be a lag time inherent in the method of analysis or detection device that must be added to the total response time.

Each of these factors increases the distance required between the detection device (or sample tap) and the automatic dump valve as shown by the following equation:

*Total distance required between valve and sample tap, in feet = (6 to 8 ft/sec) times (VR+SL+AC+MD)*

*Where:*
*VR = Time required for automatic dump valve to respond, in seconds*
*SL = Time required for contamination to travel to detection device through sample line, in seconds*
*AC = Time required for contaminant to rise to alarm concentration, in seconds*
*MD = Lag time for detection device or method, in seconds*

*Table 1. Comparison of Performance Data for Common Condensate Polishers*

| Ion Exchange | Mechanical Filters | Electromagnetic Filters |
|---|---|---|
| • Flow dependent (25 to 35 gpm/$ft^2$)*<br>• Iron leakage increases below 20 gpm/$ft^2$ | • Flow specific to filter, for example cellulosic pre-coat filters operate at 2 to 2.3 gpm/$ft^2$ | • Essentially flow independent<br>• Streams with a high percentage of magnetite may operate at 1 ft/sec |
| • 80% to 90% efficient in iron and copper, or to 5 ppb** (whichever is greater)<br>• Hardness removal to 500 ppb or less | • 85% to 90% efficient, but only removes particulates that exceed filter pore size | • Preferentially removes magnetic particles<br>• Typically removes 95% of magnetite present, approximately 90% of total iron, and 50% of copper |
| • Temperature limited. Some resins degrade in the presence oxygen ($O_2$) at temperatures as low as 100°F | | • Operation at a pH of 9.3 to 9.5, with a reducing environment (no $O_2$), and relatively high temperatures is ideal |
| • Prone to iron fouling | | |
| • Relatively difficult regeneration | • Easy regeneration | • Easy cleaning |

* gpm/$ft^2$ = gallons per minute per square foot
**ppb = parts per billion

The distance quickly becomes excessive and a failure of either the valve or detection device will still allow contamination back into the boiler system. Industrial plants with potentially nasty condensate have learned that it is much more reliable to install a redundant automatic dump system than to rely on a single system and try to get sufficient distance between sample tap and valve. The first automatic dump valve and detector should be close to the point of potential contamination. The second system can be just before the final condensate collection tank and monitor combined return streams. Be sure to consider the amount of condensate you can afford to dump (which is the amount of make-up your pre-treatment system can supply) when choosing the actual location.

If the contaminant is cationic or anionic in nature, you may be able to detect contamination by simply monitoring specific or cation conductivity. However, many particulates, suspended solids, and organics are non-ionic, and will not affect conductivity values. In those plants, an inline total organic carbon (TOC) monitor may be used to detect organic condensate contamination. Turbidimeters, particle monitors, fluorometers, and chromatographs have also had some success in detecting certain non-ionic organic contamination. Turbidimeters and particle monitors are most commonly used to detect particulates or suspended solids.

*Table 2. Additional Response Time Inherent in Sample Lines*

| Line Size (inches) | Wall Thickness (inches) | Minimum Time (seconds per linear foot) for Contamination to Reach Detector (500 ml/min) |
|---|---|---|
| 1/4 Tubing | 0.035 | 0.600 |
| | 0.049 | 0.428 |
| | 0.065 | 0.267 |
| 3/8 Tubing | 0.035 | 1.720 |
| | 0.049 | 1.420 |
| | 0.065 | 1.200 |
| 1/2 Tubing | 0.035 | 3.430 |
| | 0.049 | 3.000 |
| | 0.065 | 2.540 |
| | 0.083 | 2.070 |

Valves should be exercised and meters calibrated to assure they are working properly. Meter measurements should be verified by grab sample at a frequency that assures the protection and reliability of the boiler system. The recommended/required frequency depends on the reliability of the meter, frequency of condensate contamination, and the effect of the contaminant on the boiler system, but should typically be done at least once per week.

## Summary

Optimizing condensate return for reuse as boiler feedwater is often a viable means of reducing fuel costs and improving boiler system efficiency. Effective chemical treatment, in conjunction with mechanical system improvements, condensate polishers, and automatic dump systems can ensure that condensate is safely returned and valuable energy recovered.

## References

1. U.S. Department of Energy, *Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industries* DOE/GO-102002-1639, September 2002.
2. O. Jonas, “Combined Water Treatment Improves Boiler Reliability,” *Power*, April 1984.
3. Spirax Sarco, Inc., SC, *Hook-Ups, Design of Fluid Systems*, 2000.

## Designing Factors

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For hot (above-ambient) applications, thermal insulation reduces heat loss. On cold (below-ambient) applications, the insulation generally serves to minimize heat gain.

Thermal insulation provides many uses in industrial (such as power and petrochemical) and commercial applications. In this article, we will only discuss industrial applications. In simple terms, thermal insulation reduces heat flow from one surface to another.

In some cases, the application design purpose may seem unrelated to heat loss or heat gain. However, the net result is that heat transfer is reduced. Examples of this are insulation for personnel protection and condensation control (sweating). For personnel protection, enough insulation is provided to keep the surface below a given temperature. For condensation control, enough insulation is provided to keep the surface temperature above the dew point. In both cases, insulation is used to control the surface temperature for a desired effect other than thermal conservation. The effect, however, is that in both cases heat transfer is reduced to maintain the surface temperature at a given design criteria.

Correctly designing and specifying an insulation system is much more involved than just selecting a particular material. An insulation system can include any combination of insulation materials used with mastics, adhesives, sealants, coatings, membranes, barriers, and/or other accessory products to produce an efficient assembly to reduce heat flow. Frequently, the design of insulation systems can either determine or direct the ultimate performance of the process. Improperly designed insulation systems are subject to damage and degradation. Degradation will compromise the material's performance characteristics, and in many cases the entire process for which the insulation system was designed.

There are many different types of insulation materials available. Each has its own set of properties and performance characteristics. For each insulation material, a proper application procedure and corresponding accessory material(s) or "system" application is available. The single most important thing to remember is the word "system." This refers not only to the insulation materials, but also to the application and finish.

When asked to supply an insulation specification for a power plant or process plant, several questions must first be considered. Some examples are:

- What are the temperature limits of the items to be insulated?
- Where is the plant geographical location and what are the environmental conditions?
- What fluids are being insulated?
- Why is insulation required?
- What type of insulation material should be used?
- What type of finish is necessary?

### Temperature Limits for Insulated Items

This starts the entire design and material selection. For a power plant, temperatures range from above 32˚F to about 1,200˚F. At an ethylene plant, the range is between minus 250˚F and 1,200˚F. Two very different types of design considerations are required, although the materials and application for the 32˚F range and 1,200˚F range could be the same. This also necessitates expansion and contraction joints.

The design of hot service insulation expansion joints and insulation supports are quite important. In steam system design at 1,000˚F the piping would expand .095 inches per foot of pipe, and the insulation (calcium silicate or perlite) would contract .024 inches per foot. A total of 5.95 inches of expansion must be accounted for if the pipe length was 50 feet. The pipe expansion must still be accounted for, even though some materials will not contract (such as mineral wools). It is also important to control where the expansion will occur. On vertical piping and equipment, this is done with the use of insulation/expansion supports. Without these, all the expansion will occur at the top.

Contraction joints are just as important to cold insulation design as expansion joints are to hot insulation. If the system has an operating temperature of minus 100˚F, the stainless steel pipe will contract 0.0176 inch per foot and the insulation, depending on the material, will contract 0.01 inch per foot for cellular glass insulation to 0.102 inch per foot for polyisocyanurate insulation.

## Geographic and Environmental Factors

Geographic design considerations depend on plant location. Facilities located in hot and humid climates will have different parameters than those located in a dry, cooler climate. The National Weather Bureau; the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.; U.S. meteorological services cited data; or similar service provides local weather data that can be used in determining the minimum, maximum, and average daily temperatures, wind, humidity, and rainfall.

A review of the following parameters should give the necessary design data:

- Wind
- Snowfall
- Extreme temperatures
- Relative humidity
- Rainfall
- Water table
- Seismic readings.

It is important to know if a plant is located near an industrial complex, where potentially corrosive chemicals are present, or near coastal areas, which can affect the insulation selection, weatherproofing materials, and application procedures. Insulated equipment located near a cooling tower or ash-handling equipment will be exposed to a more corrosive environment than will other plant equipment.

Wind conditions (both positive and negative [backside negative pressure]) must be considered in insulation design. In hot service, the weatherproofing could be supported by angle irons attached to the vessel or vessel support system. The insulation material could be rigid enough to support the positive pressure of the weatherproofing, but the attachments must be strong enough to resist the negative pressure on the backside. Corrugated metal is usually preferred on vessel sidewalls held in place with stainless steel bands on 18-inch centers and screws in the vertical overlapping seams.

## Types of Fluids Being Insulated

Insulation design for pipe and equipment that handles hazardous chemicals, such as flammable or toxic materials, requires special consideration.

Insulation materials that can absorb fluids (such as hot oils/heat transfer fluids) and cause that fluid's flash point to be reduced should not be used in such service. Non-absorbent type insulation materials should be used in these services. These insulation materials may also be required for toxic services, where trapping of a toxic substance in the insulation can pose health hazards.

## Reasons for Insulation

Why is insulation required? Because it's necessary! The real question is: Will it be necessary to limit heat loss for personnel protection, to reduce heat gain, to limit surface condensation, or to provide process control? Or will it be used for product stabilization, freeze protection, noise control, and fire protection? Each of these may require different thickness, materials, finish, and extent of insulation.

### *Limit Heat Loss or Heat Conservation*

Insulation by itself will not maintain or hold temperatures within a system. Insulation can only provide a means to limit, conserve, control, reduce, or minimize the rate of heat flow through a system, but it cannot stop the process. Insulation is merely a heat flow reducer, not a barrier to heat flow.

It might be that condensate and blowdown lines to drains or holding tanks may require insulation to limit heat loss. However, heat losses through valves and flanges are not critical to the system; therefore they are not insulated (although personnel protection may be required).

### *Personnel Protection*

When designing insulation systems for personnel protection, only enough insulation should be used to reduce the surface temperature to an acceptable limit to prevent individuals from being burned. Traditionally, the insulation surface's upper temperature for personnel protection is 140˚F. To date, no mandates or statutes govern the upper limit for personnel protection. Refer to ASTM C1055 *Standard Guide for Heated System Surfaces Conditions That Produce Contact Burn Injuries* (1) for guidance in selecting acceptable temperature limits.

Insulation for personnel protection is generally applied only in those areas accessible to persons during normal plant operation and maintenance, and applied to a high of 7 feet above or 3 feet from platforms or work areas. In some system designs where there is no justification for insulation, and the insulation could actually be detrimental to the process. Fabrication guards may be employed to provide personnel protection.

When insulation is used for personnel protection, it is very important to flash the ends to prevent water or moisture from getting behind the insulation, and to prevent insulation deterioration and surface corrosion. Note that most mastics and sealants could have temperature limits lower than the operating or design temperature of the surface for personnel protection.

In situations where solar loads are high, highly reflective metal jacketing materials reflect much of the radiant heat, thereby creating surfaces that could be too hot to touch. Dull, textured, or painted surfaces tend to absorb more of the radiant heat, creating a surface condition cooler to the touch. Gray-coated metal jacketing can reduce insulation thickness for personnel protection by as much as 2 inches. As a general rule, the closer the materials emittance is to 1, the cooler the surface temperature will be.

Wind conditions also influence the selection of insulation for personnel protection. For example, in open areas in coastal regions, a prevailing wind is usually present, which can be considered in the insulation design. In this situation, less insulation would be required than in an enclosed space sheltered from the wind.

### *Reducing Heat Gain on Cold Surfaces*

In below-ambient applications, the main objective for providing insulation is to reduce heat gain and prevent moisture migration or water intake into the system. This type of moisture migration will have a dramatic effect on insulation performance. Cold systems are more subject to degradation from the environment than are hot systems, because of the direction of the vapor driving force. On hot insulation systems, the water vapor’s driving force is away from the hot surface; and although the ingress of water into the insulation can adversely affect performance, it is generally considered to be temporary. Conversely, on cold systems, the water vapor’s driving force is inward toward the colder surface.

The ingress of water into the insulation will gradually increase with time. The moisture will slowly deteriorate and eventually destroy the system. For this reason, it is extremely important that the total insulation system design be detailed and well-planned, using vapor barrier mastics, vapor barrier stops, and low-permeability joint sealants.

Usually, the cost of removing British thermal units (Btu) (heat gain) by refrigeration is greater than that of producing process Btu (heat loss) by heat generating equipment. Therefore, the heat gain in cold processes must be kept to a minimum. The rule of thumb is to provide sufficient insulation to maintain heat gain of 8 to10 Btu per hour per square foot (hr/ft$^2$) to the cold process. The design’s ambient temperature and wind conditions must be utilized when calculating the insulation thickness.

In cold insulation system design, vapor barriers and vapor stops are extremely important. Vapor stops, which seal the insulation to the pipe or equipment, should be installed at all insulation protrusions and terminations. These vapor stops will prevent any failure of the insulation system from traveling along the entire system.

### *Limiting or Controlling Surface Condensation*

Insulation systems can be designed to limit or retard condensation, but in most cases they cannot be designed to prevent condensation. In humid regions it’s unfeasible to consider designing an insulation system to prevent condensation 100% of the time. In these areas, the required thickness of even the most efficient insulation would be unrealistic from both a financial and practical standpoint.

Insulation thickness is determined using ambient conditions and relative humidity, along with the process operating temperature and surface emittance. The insulation system should be designed to keep the surface temperature above the dew point of the ambient air. This will keep condensation from forming on the outer surface of the insulation, avoiding safety hazards and preventing dripping condensate on buildings or electrical equipment. It is essential to agree on how often condensation is acceptable.

In hot and humid outdoor environments and during rain, it is virtually impossible to prevent condensation 100% of the time. If the insulation thickness is designed to allow for a heat gain of 8 to 10 Btu per hr/ft$^2$, this will be sufficient to prevent condensation the majority of the time.

### *Providing Process Control*

Process control is a critical design parameter in many industrial applications, particularly for steam and critical process piping and equipment. Providing a stable temperature flow and heat loss throughout a process system is, in many cases, more important than any other system design.

When designing for process control, other information is also necessary, such as determining what heat loss or temperature must be controlled. What pipe length and equipment size? How is the piping and equipment supported? Are they on insulated shoes, vessel skirts, legs, or other components? Also, any protrusions should be accounted for in the heat loss.

### *Freeze Protection*

Freeze protection can be maintained by fluid flowing insulation or by insulation with some form of additional heat input. Insulation alone cannot maintain a temperature. It will delay the time required for a fluid to reach a design temperature, but it cannot (or will not) stop it.

In the Gulf Coast region, generally most stagnant water lines in sizes 6 inches and smaller should be heat-traced and insulated. Only lines between 8 feet and 12 feet need insulation.

Freeze protection could also refer to prevention of product solidification. In product solidification, additional heat input is usually required to replace the heat loss through the insulation. For example, heavy fuel oil might have to be maintained at 250˚F and will require additional heat input to replace the heat loss through the insulation.

### *Noise Control*

Environmental acoustic issues can be addressed by thermal insulation system design. However, serious noise problems should be treated as a separate and independent study.

Sound attenuation is a natural by-product of the insulation design. Because of their sound absorption characteristics, some insulation and accessory products provide greater sound attenuation than others. Mineral fiber products are among the best thermal insulation materials for sound attenuation.

The jacketing material used to cover the insulation can play an important role in sound attenuation. A fabric-reinforced mastic finish over insulation has better sound absorption properties than metal jacketing. Metal jacketing may also be purchased with a loaded mass to reduce noise.

### *Fire Protection*

As a general rule, insulation materials are better suited as insulation than as a fire protection product. However, the American Petroleum Institute (API) acknowledges conditions under which some insulation materials may provide “credit” in the design and sizing of pressure relief valves. *API Recommended Practice 521* (2) states insulation system requirements. Included is a requirement that the finished insulation system will not be dislodged when subjected to the fire/water stream used for fire fighting, either by hand lines or monitor nozzles. Most insulation systems used in fire protection are metal with stainless steel jackets and bands, which meet these criteria.

### *Physical and Mechanical Conditions*

Physical and mechanical conditions also play an important part in insulation system design. Indoor applications generally do not require the complexity of outdoor designs. Similarly, below-ambient applications are more complex than hot applications. The physical abuse and mechanical conditions that an insulation system is subject to are also important to consider during design.

Rigid insulation is resistant to deformation when subjected to foot traffic. Compressible insulation does not offer the same resistance to such loads. Areas that experience loads or repetitive personnel access/use will require a firmer system than inaccessible areas. Piping used as ladders/walkways and riggings hung from pipes and horizontal surfaces subject to vibration/loads are examples where rigid insulation is required. Compressible insulation is required for filling voids and closing gaps in insulation, which allows expansion, contraction, or movement of rigid insulation.

Mechanical abuse should be considered case by case. Insulated items located in high traffic areas should have a structure such as a platform or similar protection, to avoid having personnel stepping directly on insulation.

## Insulation Materials

There are many types of insulation materials available for industrial application, though there are too many to discuss in detail here. A few of the most common industrial insulations and types will be described. These are:

- Calcium silicate
- Cellular glass
- Fibrous materials (fiberglass and mineral wool)
- Perlite
- Polyisocyanurate foam.

The *Insulation Material Specification Guide* (3) from the National Insulation Association's (NIA) National Insulation Training Program, which may be obtained by contacting NIA at *www.insulation.org*, gives a quick comparison of ASTM values for these and other insulation materials.

When comparing material properties, keep in mind that ASTM test methods are usually performed under laboratory conditions and may not accurately represent field conditions. These depend on process temperatures, environment, and operating conditions.

### *Calcium Silicate*

Calcium silicate insulation is a rigid, dense material used for above ambient to 1,200˚F applications. This has been the industry standard for high-temperature applications. It has good compressive strength and is non-combustible.

### *Cellular Glass*

Cellular glass insulation is also a rigid, dense material normally used in the temperature range from minus 450˚F to 400˚F. Its closed-cell structure makes it preferable for low-temperature applications, and for use on services where fluid absorption into the insulation could be a problem.

### *Fibrous Materials (Fiberglass and Mineral Wool)*

Fiberglass and mineral wool are actually two separate types of insulation. However, many of their applications and physical properties are the same. These products are generally not used where mechanical or physical abuse could occur. Although they may be used in high temperatures, some of their physical and acoustical properties may be lessened.

### *Perlite*

Perlite insulation is generally used in the same type of applications as calcium silicate insulation. However, it is somewhat lighter in density and lower in compressive strength then calcium silicate. It is treated with a water inhibitor, which prevents the material from absorbing atmospheric moisture during storage and installation.

### *Polyisocyanurate Foam*

Polyisocyanurate foam insulation is used in temperature ranges from minus 200˚F to 300˚F. It has very good thermal properties and is 90% closed cell. In cold service application, it requires multiple layers because of its contraction characteristics.

## Accessory Materials

The insulation's accessory materials used are as important as the insulation material itself. If the wrong accessory material is selected, the system will not provide the required performance.

Typical accessory materials include acrylic latex mastic, aluminum jacketing, stainless steel jacketing, stainless steel bands and screws, hypalon mastic, and electrometric joint sealers.

Metal jacketing is preferred to mastic for most outdoor applications because of its durability.

Colored jacketing should be used for cold service and personnel protection insulation to reduce surface emittance from 0.01 for new aluminum to 0.8 for colored aluminum, which will reduce insulation thicknesses.

## References

1. ASTM International, ASTM C1055, *"Standard Guide for Heated System Surfaces Conditions That Produce Contact Burn Injuries,"* 2003. For referenced ASTM standards, visit the ASTM Web site, *www.astm.org*, or contact ASTM Customer Service at *service@astm.org*. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM Web site.

2. American Petroleum Institute, *API Recommended Practice 521—Guide for Pressure Relieving and De-Pressuring Systems*. 4th Edition. March 1997, *www.api-ep.api.org.*

3. National Insulation Association's (NIA) *Insulation Material Specification Guide, www.insulation.org.*

## Insights for Insulation Installation

*Gordon Hart, Consultant/National Insulation Association*

With the price for natural gas exceeding $9 per million British thermal units (MMBtu) in Spring 2003, and the price for a barrel of crude oil recently hovering between $25 and $40, the time may be coming when facility owners and operators begin recognizing thermal insulation's significant role in reducing thermal energy use. Sustained high energy prices will drive this message home. You may recall that we experienced high energy prices in the first half of 2001, followed by a quick and dramatic collapse. A similar price drop is not likely to recur. If natural gas prices remain around their current level for at least a year, this pricing could start to have a profound impact on our attitudes toward energy conservation, and in particular thermal insulation use.

Many insulation industry professionals have taken the National Insulation Association's (NIA) Insulation Energy Appraisal Program (IEAP). In that program, attendees learn to use the North American Insulation Manufacturers Association's (NAIMA) 3E Plus® computer program to calculate heat energy loss or gain differences between insulated and uninsulated surfaces. Hence, participants learn about the dramatic energy savings resulting from the correct use of mechanical insulation and the penalties paid by industrial facility owner/operators for leaving portions of their process piping and equipment uninsulated, either through neglect or design. Payback periods for insulating bare surfaces are typically a matter of months. The specific time is largely dependent on the price of energy used in the analysis. The 3E Plus program can also be used to estimate the economic penalty that results from insufficient insulation in piping and equipment. This program is free and can be downloaded from NAIMA at *www.pipeinsulation.org.*

As with evaluating the heat loss or gain differences between uninsulated and insulated surfaces, there are installation issues, that can lead to excessive heat loss. Some, which can have a large impact on energy use, include:

- Gaps at butt joints or resulting from inadequate installation fit
- Wet insulation resulting from improperly fitted and/or caulked lagging
- Condensation on cold surfaces from insufficient design thickness required to maintain surface temperatures above dew point and/or inadequately installed vapor readers
- Prematurely damaged or degraded insulation, either through vibration or some other external factors, resulting from less than adequate installation.

To avoid installation deficiencies, the owner/operator should also consider requiring the insulation contractor to implement a formal quality assurance (QA) program, along with offering an extended warranty on the work. Finally, it is worth considering the benefits of verifying insulation performance through the use of infrared (IR) inspections. This can be done shortly after facility start-up and at a later time during the warranty period.

### Increased Heat Loss from Gaps and Penetrations

If gaps develop at butt joints or other joints between adjacent pieces of insulation in single-layer jobs, the additional heat loss or gain can be excessive. As a rule, the heat loss from a hot, bare surface can be about 20 times greater than from a surface insulated to industry standards. Therefore, if, during plant operation, the gaps make up 2% (1/50) of the total surface, the heat loss or gain could be about 40% greater than it would be without the gaps. For 36-inch, preformed sections of pipe insulation, 2% gaps translate to only 3/4-inch per section (this is during facility operation and after the pipes have expanded, not necessarily when installed on ambient-temperature pipes).

Gaps can sometimes be the consequence of an inadequate specification—one that does not require expansion/contraction joints (through the installation of a compressible insulation material in the butt joints between adjacent pieces of rigid insulation), or does not require double layer on thick insulation applications. However, gaps can also occur when insulators simply neglect to install the compressible insulation in those expansion joints, and inspectors do not catch the deficiency.

Likewise, at insulation penetrations, such as at pipe hangers, supports, or other obstructions, gaps may occur during plant operation because of the contractor's inadequate attention to installation details. Hangers and supports are also sources of higher heat loss, and should be at least partly insulated beyond the primary insulation surface to prevent excessive heat loss.

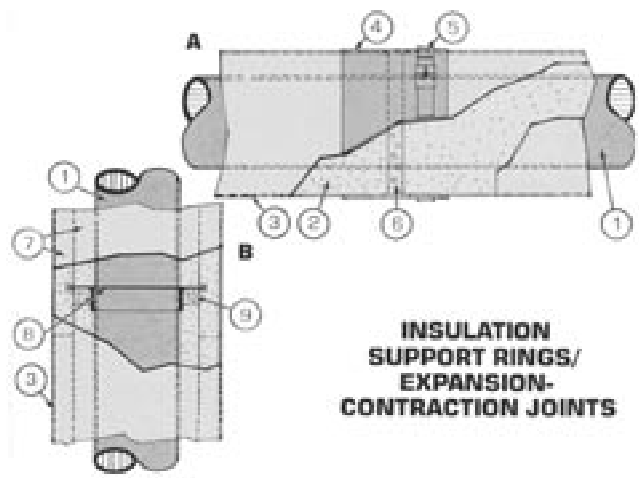



*Figure 1. Plate #9 From Midwest Insulation Contractor's Association.*

Figure 1 is Plate #9 from the Midwest Insulation Contractor's Association (MICA) *National Commercial & Industrial Insulation Standards* manual (1) showing the correct way to install an expansion/contraction joint at pipe support rings by using a compressible form of insulation in that joint. Figure A, Segment 2 refers to the single-layer pipe insulation. Segment 6 refers to the flexible fibrous insulation in the expansion/contraction joint. Likewise, for the use of a support ring shown in Figure B, Segment 8 is the steel support ring, and Segment 9 is the flexible fibrous insulation used as filler in that otherwise void space.

## Wet Insulation

For outdoor applications, as well as indoor applications in which the insulated pipes and equipment are frequently washed with spray water, water could potentially get into the insulation. This can be avoided by a design specification requiring an adequate jacketing with sealing and caulking of lap joints, water shields, and other details at pipe hangers and supports. The difficulty of avoiding wet insulation is compounded by the "out of sight, out of mind" concept. If the jacketed insulation looks good, many owner/operators assume it is performing as designed. To imagine the penalty to the owner/operator of an industrial facility operating his plant with wet insulation, let's consider an analogy.

You have probably heard of people who celebrate New Year's Day in Chicago by putting on their swimsuits and jumping into Lake Michigan. When these people get out of the water (probably very quickly, I might add) they have dry towels ready as well as dry, warm clothing. Now, try to imagine joining these people, except you will wear warm, well-insulated winter clothing, such as down ski attire, thick socks, gloves, and a ski cap. Then you jump into the lake with them.

After getting out of the frigid lake, imagine standing around in the cold air, or maybe taking a brisk walk up Chicago's windy Michigan Avenue in below freezing temperatures with this wet insulated clothing (though this is not recommended for those of us who value their health—simply imagine how you would feel!) In heat loss terms, your body would experience something similar to what the hot pipe with the wet insulation would experience. And that pipe, with the wet insulation, could operate in this condition for months or even years until the problem is identified and remedied. Yes, on a very hot pipe, it may dry out, but with tightly sealed, weather-resistant jacketing, the outer portions of the insulation could remain wet.

It is also in the owner/operator's interest to ensure that no wet insulation is installed. Therefore, it is critical to pay attention to the manner of handling and storage, along with the weather, when installation takes place. If certain types of insulation are installed wet, there is a good probability that some will remain wet, maybe for a long time, following plant start-up. This situation can also be imposed on the insulation contractor by working on a fast track job in which the general contractor (GC) requires his subcontractors to work in wet weather, without protecting the insulation. It is important for the owner/operator to make certain that fast track specifically precludes the GC's schedule permitting the new insulation to get wet prior to installation.

The consequences for an industrial facility owner/operator to run his facility with wet insulation can be severe. The more wet insulation on a job, the more severe will be the excessive heat loss or heat gain problem because of an increase in thermal conductivity caused water presence. It is in the owner/operator's interest to ensure that dry insulation is initially installed, and that the weather barrier jacketing is correctly installed, caulked, and sealed to keep the insulation dry for a long time.

## Vapor Condensation on Chilled Piping and Equipment

Chilled piping and equipment that has insulation design thickness or an inadequately installed vapor retarder will allow moisture to migrate to the chilled surfaces and condense. On surfaces with operating temperatures above 32˚F, it will result in moisture build-up on the chilled surface and in the thermal insulation itself. On surfaces with operating temperatures below 32˚F, the result will be ice and moisture build-up. As with insulation that becomes wet from rain caused by an inadequately installed and sealed jacket, insulation that becomes wet from moisture condensation will conduct more heat to the cold surface than dry insulation. This means higher energy use to maintain the cold fluid in the pipe or equipment.

Additionally, because a pound of water releases almost 1,000 Btu of heat energy to the cold surface, there is an additional energy penalty beyond wet insulation. Finally, the water can eventually drip and lead to other surfaces becoming wet that are not designed to be wet. This is particularly a problem for chilled piping in buildings; condensation can lead to wet building materials, such as wood and drywall, which, in turn, can lead to their damage, possibly with mold growth.

To avoid these moisture condensation problems, the owner/operator must be certain that the insulation design thickness is sufficient to maintain the outside surface of the insulation above dew point Additionally, the installation must be performed according to the specification. This means that the vapor retarder must be completely intact, whether through the use of tape, mastic, or other material. Furthermore, the vapor retarder must not have holes, gaps, or other damage. If a separate jacketing is installed after the installation of the vapor retarder, and damage has been done to the vapor retarder, then we have an "out of sight, out of mind" issue again until water starts dripping out of the insulation at gaps in the jacketing. The time to avoid this sort of problem is during original insulation installation by installing the insulation and the vapor retarder correctly.

When using closed-cell foam insulation, it is critical that the installer correctly seal all joints to prevent migration of moisture to the cold pipe or equipment surface. The water vapor transmission of closed cell insulation is low, but will only be effective with correct installation. Another newer way to avoid these problems on chilled water lines is with properly installed, mineral fiber "wicking" pipe insulation system. While this allows moisture to migrate to the chilled pipe, it also provides for gravitational draining, wicking, and evaporation of the water. As with other systems, correct installation of the wicking system is required. However, the "wicking" type systems are new, and there is a limited amount of published data on their performance. Time will tell whether there is an improvement over conventional chilled water pipe insulation systems with a sealed vapor retarder or sealed closed-cell foams.

## Prematurely Damaged Insulation and System Longevity

Certainly, no thermal insulation system can be expected to last forever. Some mineral fiber insulation boards on boilers can be expected to eventually settle from vibration or temperature excursions, after many years of service. For example, if a hurricane hits an industrial facility with insulated outdoor piping, equipment can be expected to tear off or damage some insulation materials. Most thermal insulation systems that are walked on regularly will degrade, regardless of their compressive strength. Some with low-compressive strengths will degrade very quickly with foot traffic.

However, there are installation details, which if correctly adhered to, can ensure mechanical insulation systems will last at least for the period of the warranty. They may even last for many years beyond, if the insulation is not physically abused.

A well-written insulation system specification should identify the type and thickness of jacketing the type, size, and spacing of attachment hardware; and the type, size, and spacing of banding. It is in the owner/operator's best interest to ensure that the installation contractor follows these details according to the specification. Viewed from a distance, one insulation system with its system components correctly installed, and another with a less than adequate installation, may look identical. However, a closer inspection will reveal the deficiencies of the latter.

While a hurricane or other excessively strong winds may damage an outdoor thermal insulation system, expected seasonal winds should not. If the specified jacketing is too thin, wind damage may cause bending of even a small part of the lagging. This, in turn, will likely allow rain access to the insulation, causing much greater heat loss or gain, as noted earlier. In addition, lagging of inadequate thickness will not provide adequate protection from mechanical abuse as expected by the owner/operator. Overall, it serves the owner/operator's purpose to have an active instead of passive interest in the installation of his new mechanical insulation systems.

## Achieving Quality Installation

To achieve a quality installation, owners/operators of industrial facilities, or their GC, should select an insulation contractor with a reputation for doing quality work. With many reputable NIA member contractors operating in different parts of North America, there are plenty of good choices. However, the owner/operator should and can do more to ensure a quality insulation installation. One important step is to require that the contractor has and implements a formal QA program. We have heard increasingly in the last decade about formal QA programs, such as ISO 9000. There are others, such as NQA-1, which, in this author's opinion, are equivalent to ISO 9000 if properly implemented. Whatever the program, it must have formal written procedures. Most formal QA programs have procedures addressing at least the following:

- Organization of both the company and the job site personnel
- Description of the QA program
- Review of customer's purchase order(s)
- Control of customer supplied materials, parts, and components
- Purchasing of materials and services
- Control of document distribution
- Control of design
- Control of purchased materials, equipment, and services
- Identification of materials, parts, and components
- Control of special processes (typically welding)
- Inspections
- Handling, storage, packing, and shipping of materials
- Training of personnel
- Control and disposition of defective materials, parts, and components
- Corrective and preventative actions
- Control of QA and other project related records.

In general, the insulation contractor should have a QA manager who has organizational freedom from the project management. The QA manager should report directly to a higher level of management, to someone who is free from profit and loss responsibility for the particular project. The contractor should have an approved vendor list for materials and services procurement, and a purchasing procedure to assure that correct materials are purchased, per the project specification. The QA manager should have a training program for the craftsmen, inspectors, and other personnel who affect the job quality. The manager should also have inspection procedures for the particular insulation project, prior to, during, and after completion. Overall, the contractor should have procedures describing how the job will be performed. These procedures do not have to be complex and lengthy. They should simply state what the contractor does and indicate when it is done. Then, the insulation should perform according to the procedures.

*Photo 1. Insulation panels during installation.*

Photo 1 shows insulation panels during installation. A good QA program would require a quality control (QC) inspector to perform inspections using a sampling plan that represents some percentage of the insulation boards' installation, prior to covering it with the metal jacketing. Once covered, it is very difficult to evaluate the installation quality of the insulation boards other than with IR spectrometry.

Design is one element of a QA program for which an insulation contractor is generally not held accountable. The owner/operator (or designated representative, such as the engineer) is responsible for design, which includes writing the insulation specification. However, the insulation contractor always has some latitude in determining system details. If the insulation contractor were required to make assembly drawings calling out the details of the job beforehand the overall quality could be improved by allowing the owner/operator to review those details and comment prior to the start of installation. To do this, the owner/operator would have to require all bidders to make drawings, which will obviously add some initial first cost to the job. However, in the end, it will pay for itself with greatly enhanced communication, improved attention to details, updated (as-built) drawings at the end of the job, and reduced cost for future insulation maintenance.

Overall, it is in the owner/operator's best interest to require the insulation contractor to have a formal QA program. And, the owner/operator should review and accept the contractor's QA program prior to the start of the job (and maybe even as part of the process of determining an approved bidders list). This will ensure the owner/operator that the contractor has the self-monitoring capabilities to perform quality insulation installation.

## Post-Installation IR Inspection

After the contractor has completed the insulation installation and final inspections, but prior to plant start-up, the owner/operator, or their design engineer, should conduct a physical inspection of the entire insulation job. After completing the inspection, making necessary repairs, and starting up the plant, the owner/operator should conduct a thorough IR inspection of the newly insulated piping and equipment.

While the owner/operator should obviously hire a skilled IR technician to conduct the inspection, he should also hire a second person skilled both in the art of thermal insulation and in examining IR photographs. This expert should accompany the IR technician to ensure that 1) all the relevant insulation surfaces are inspected, 2) the IR camera is correctly adjusted, and 3) the final IR results are correctly interpreted. An IR device must be adjusted to detect differences of sufficient magnitude and to identify annulated surfaces, gaps, wet insulation, or other insulation deficiencies. The expert is needed to differentiate between areas of poor insulation performance and areas with thermal bridging caused by heat loss through structural steel, the latter being unavoidable by the insulation contractor.

At one time, IR equipment was extremely expensive and cumbersome to use. However, today it is much more affordable, there are many companies that can provide the services, and the equipment is relatively light and user friendly. With an IR camera, either still or video, the inspectors can make an IR record of the job.

If the IR inspections detect areas with high heat loss or gain and the expert determines that these are caused by insulation deficiencies, then the insulation contractor should be required by contract to make repairs. Because such repairs can be expensive, it will obviously be in the best interest of the insulation contractor to

*Photo 2a. Visual of panel system.*

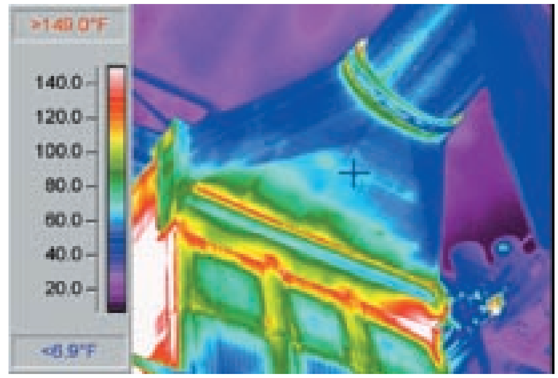



*Photo 2b. Infrared photo of the same panel system showing high surface below the connecting horizontal duct.*

make certain that his crew does a high-quality original installation, per the specification. This means ensuring that the QC inspector does a thorough inspection during and following the installation process.

Photo 2a shows a section of a panel insulation system, which appears to be in excellent condition. However, Photo 2b the corresponding IR photo, shows areas of high heat loss, caused either by wet insulation or insulation gaps. In this case, the IR inspection reveals a serious insulation deficiency beneath the connection between the horizontal duct and the vertical panels. The surface temperatures in this area are as high as 149˚F, whereas the general surface temperatures on the flat panels are only in the range of 50˚F and 70˚F.

Another example of the power of IR inspections is shown in Photos 3a and 3b.The former is a photo of an elbow. While the photo shows that there is some obvious physical damage to the metal jacketing, the extent of the damage is not revealed until you look at the corresponding IR image. Note that the surface temperatures on the top of the elbow reach as high as 211.5˚F. While the IR photo does not show the portions of the pipe below the elbow, the scale does indicate that there are insulation surfaces with temperatures as low as 92.9˚F. The high surface temperatures indicate areas with excessive heat loss, probably caused by wet and/or damaged thermal insulation beneath the jacketing.

*Photo 3a. Partially damaged insulation on a pipe elbow.*

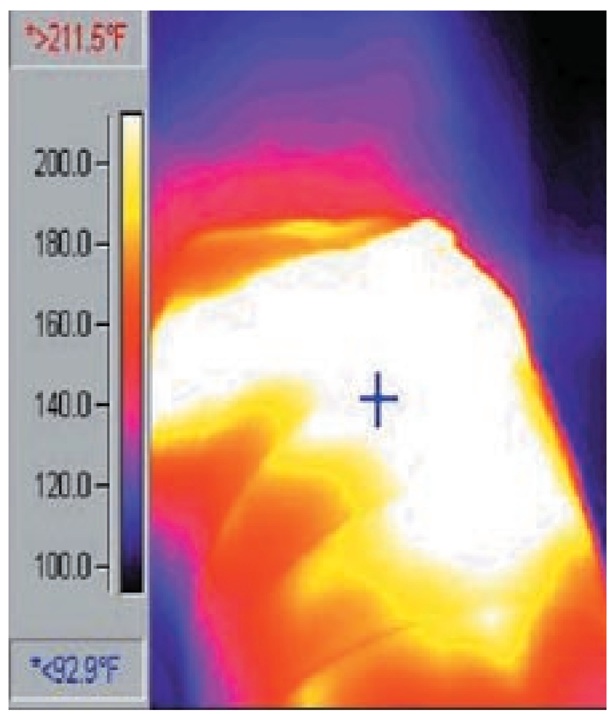



*Photo 3b. An infrared photograph of the top of the same areas as seen in Photo 3a showing an area with high surface temperatures.*

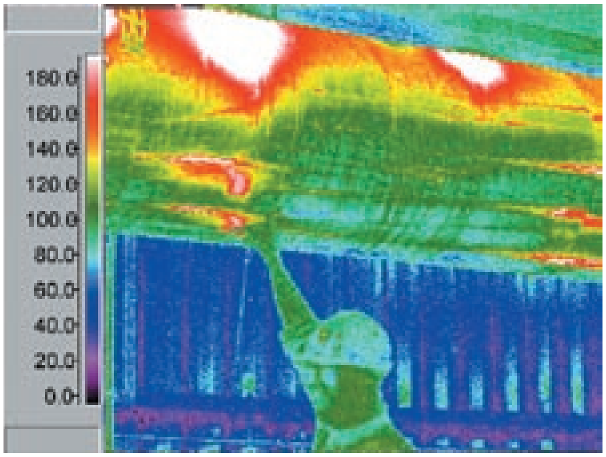



*Photo 4. An insulated horizontal seam shows two large areas on the top surface with surface temperatures in excess of 180˚F, as well as some smaller areas on the lower half of the pipe. Note that the well-insulated areas have surface temperatures in the 80˚F to 100˚F range.*

Photo 4 shows the successful use of IR thermography to detect areas of high heat loss, in this case on a horizontal, insulated pipe. While it is not obvious what is causing the two areas of high surface temperature on the subject pipe, it is clear that there is something defective about the insulation material, either being wet, damaged, or incompletely installed.

A word of caution about using IR thermography: this method does not work well on new, shiny metal surfaces with low emissivity values (lower than about 0.2). Therefore, for new insulation systems, it may be necessary to wait several months prior to conducting an IR study. For an exterior job, exposed to the weather and to dust settlement, a year should be sufficient to increase the surface emissivity to 0.2 or above, allowing IR to be effective.

## Warranty Benefits

The owner/operator should require that the installation contractor provide a warranty for an extended time period of at least 12 months, and should include installing the correct materials of acceptable quality, per the specification. It should also include the less obvious, namely that the system performs per the specification for some period of time following installation.

For example, if the system's jacketing leaks, resulting in wet insulation, without being caused by external damage to the jacketing or other in-service abuse, the installation contractor should be responsible for the repair.

Conversely, the contractor should not be responsible for temperature excursions or physical abuse of the insulation caused by the owner/operator. These inspections, prior to the end of the warranty period, can be a combination of a physical inspection and an IR inspection. If the IR inspection detects areas of high surface temperature, then jacketing may have to be removed to determine the nature of the deficiency (such as wet or deteriorated insulation). Again, an insulation expert should be able to differentiate between an insulation problem and expected high heat loss or heat gain resulting from thermal bridging through structural members.

## Taking an Active Interest

To ensure a high-quality installation of a mechanical insulation system, a facility owner/operator should take an active interest in the design and installation of the thermal insulation system. This should include selecting a qualified insulation design specialist and a proven installation contractor. Part of the selection should include the insistence that the contractor has a formal QA program that requires an extended warranty on the work, inspections of the installation during the project, and a final inspection.

The owner/operator or design engineer should also hire a qualified IR thermography technician and an insulation expert to perform follow-up physical and IR inspections both at completion of the job and prior to expiration of the warranty. With this type of active interest, the facility owner/operator can take comfort knowing that not only has he purchased a quality installation, but also that the insulation system will perform as expected. He can thereby avoid high heat loss or gain problems caused by wet insulation (whether caused by leakage or condensation or prematurely damaged jacketing), gaps in the insulation, prematurely deteriorated insulation materials, or other avoidable deficiencies.

The owner/operator and the design engineer should remember that many insulation deficiencies are invisible to the naked eye. They both must learn to look below the surface, preferably during and immediately following insulation installation, to determine whether those problems exist. In short, they both must take an active interest in their insulation systems.

## References

1. Midwest Insulation Contractor's Association, *National Commercial & Industrial Insulation Standards Manual*, 1999, *www.micainsulation.org.*

# Insulation Management and Its Value to Industry

*Michael J. Lettich, MJL Consulting/National Insulation Assocation*

Just look at any chemical, petrochemical, or petroleum refining facility. Much of what you might see is insulated piping, equipment, and vessels. It sure looks like there is a lot of it. As a matter of fact, there is a great deal of insulated pipe, equipment, tanks, and vessels. As an example, let's consider a "typical" mid-size chemical plant and oil refinery. A mid-sized chemical manufacturing plant might contain more than 61 miles of insulated piping and more than six football fields (270,000 square feet [$ft^2$]) of insulated equipment, vessels, and tanks. A medium-sized oil refinery contains 356 miles of insulated piping and more than 32 football fields (1.4 million $ft^2$) of insulated equipment, vessels, and tanks.

It seems clear that insulation serves an important role in the operation of all chemical, petrochemical, and oil refining facilities. But why is it important?

- **Process control is first and foremost.** Insulation helps retard the flow of thermal energy into or out of a process, keeping temperatures stable, allowing chemical reactions to proceed normally and safely to manufacture the chemical and oil products.
- **Energy conservation is next.** Without insulation, thermal energy would escape uncontrollably to the atmosphere, wasting billions of dollars. Figure 1 illustrates the energy loss from an uninsulated 4-inch pipe versus one insulated with 2 inches of insulation and covered with aluminum jacket.
- **Freeze protection is important for facilities in northern climates.** Without adequate insulation on critical service equipment that supplies cooling or fire protection water, steam condensate, and other aqueous solutions, they would freeze, preventing them from performing the service they were intended to do. The freezing of this equipment also results in rupture and breakage of pipe and equipment because of water's unique property to expand when frozen. This results in millions of dollars of damage along with the potential for serious environmental and personnel safety problems.

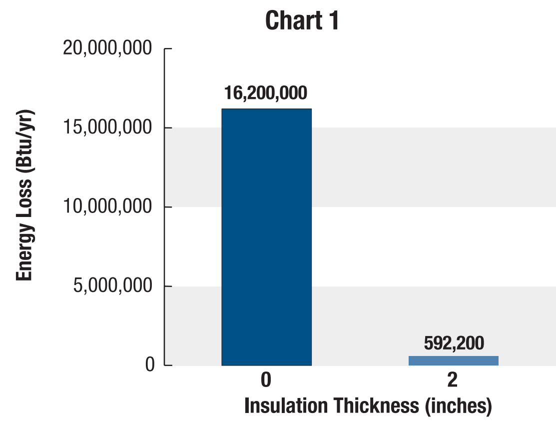



*Figure 1. Thermal energy loss for bare versus insulated 4-inch pipe.*

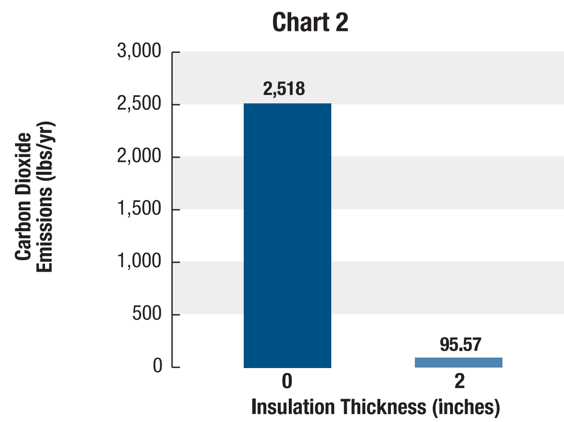



*Figure 2. Carbon dioxide ($CO_2$) emissions comparison for bare versus insulated 4-inch pipe.*

Note: Charts 1 and 2 – Data for 4-inch carbon steel pipe at 350˚F
Source: NAIMA 3E Plus® Computer Program

- **Personnel protection from burn hazards provides an important insulation service.** Much of the insulated pipe and equipment in a chemical plant or oil refinery operate at temperatures ranging from 200˚F to more than 1,000˚F. These are located near where plant employees and contract personnel work on a daily basis. Insulation is frequently the only barrier keeping personnel safe from these hazards.
- **Emissions control, although frequently not recognized, is another service insulation provides to an industrial plant.** Figure 2 shows the emissions loss from the same 4-inch pipe, comparing bare versus 2 inches of insulation.

| | Mid-Size Chemical Plant | 150,000 bpd Refinery |
|---|---|---|
| Insulation Damage | 19.2% | 21.3% |
| Corrosion Under Insulation (CUI) | $250,000 annually | $500,000 annually |
| Energy Loss ($5/MMBtu) | $1,829,000 annually | $10,664,000 annually |

*Figure 3. Typical damage and costs from poorly maintained insulation in industrial facilities.*

## Industry Appreciates Insulation—Or Does It?

With all the essential service insulation performs for industry, it must be an important element in each facility's maintenance program …right? Well, let's look at those chemical plant and oil refinery examples discussed earlier. Figure 3 shows the typical damage present, the problems created, and their costs. Another way to look at the scope of the problem is in terms of asset value. Take that typical, mid-size chemical plant with existing damages, assuming an invested value of $500 million. A normal chemical plant contains from 6% to 10% of its asset value in insulation systems. This means there is between $30 million and $50 million worth of insulation damage to this facility. With the cost of energy from about $4 per million British thermal units ($4/MMBtu) to more than $10/MMBtu, repairs to many of these damaged insulation systems would yield from 30% to more than 300% return on the investment (ROI). With this kind of damage and the potential for excellent payback once repaired, it looks like insulation maintenance is not managed as well as

*Photo 1. Bare pipes.*

*Photo 2. Cosmetic damage on pipes.*

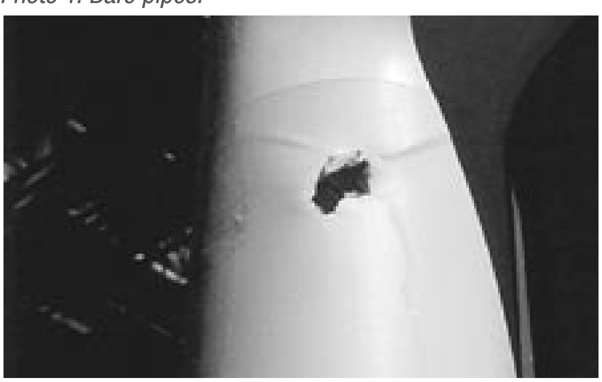


*Photo 3. Jacket damage.*

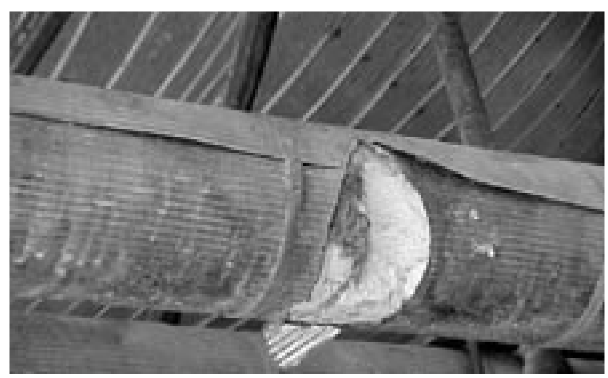


*Photo 4. System patch.*

*Photo 5. Sealant failure.*

*Photo 6. System failure.*

it should be. It also does not seem to be considered very important, despite compelling evidence. Why? Quoting a fellow consultant and friend, V. S. Pignolet of Balmert Consulting: "For something to get fixed, it first must be noticeable. Then the level of damage must be objectionable." The abundance of insulated pipe and equipment that surrounds industrial facility managers makes it difficult to recognize the impact of what looks like such a small amount of damage. However, often the biggest reason is that much of the damage is either not noticed or viewed as not important. Insulation damage ranges from cosmetic, such as staining, to completely bare equipment. Examples of each type of damage are illustrated in Photos 1 through 6.

A good example of "not noticed" was an insulation assessment I performed at a chemical plant in the Texas Gulf Coast. The plant's management was concerned about the quality and capacity of their steam delivery system. Often, the steam pressure was dramatically reduced and there was an excessive amount of condensate within the system at the end of the main utilities distribution pipe rack. As a result, those production manufacturing facilities were having a more difficult time operating efficiently.

*Photo 7. Midwest chemical plant with damaged vapor retarder.*

As I started my assessment survey, I interviewed personnel from the utilities area. These personnel indicated that each time it rained they had to add about 25% more steam generating capacity in order to meet the demand. Since this was the Texas Gulf Coast, the plant saw rain.

Looking at the utilities distribution pipe rack from the ground showed only incidental damage to these steam pipes. However, once I gained access to the top of the pipe rack, the picture changed. These steam lines were installed with glass fiber insulation covered with corrugated aluminum jacketing (great for trapping water and diverting it into the insulation when used on horizontal runs). Over the years, maintenance activity, storms, salt in the air from the Gulf Coast only a few miles away, and the mildly corrosive atmosphere resulted in numerous small holes in the aluminum jacketing. The result? Each time it rained, nearly the entire run of steam lines in this pipe rack was ruining the insulation efficiency and condensing the steam before it could get to many of the process facilities. The project designed to upgrade this damage yielded more than 150% ROI for the energy savings alone. In addition, each production facility found a more reliable source of steam with less difficulty efficiently operating their facilities.

A case of "not realizing" was an insulation assessment I performed at a chemical plant in the Midwest. This plant operates much of its facility well below 0˚F, with some in the cryogenic ranges below minus 100˚F. The insulation system was cellular glass with an applied "asphalt cutback" vapor retarder and aluminum jacketing. At a casual glance most of the insulation systems looked intact. However, most of the piping, equipment and vessels showed extensive condensation and mildew growth on the jacketing (Photo 7). Over time (with the help from some maintenance and shutdown activity damage), the vapor retarder had failed, filling the system with moisture.

Figure 4 shows the loss of insulation efficiency as a result. Again, with refrigeration energy costs of almost $40/MMBtu, a project with excellent ROI was developed. Also, the refrigeration units could run during the peak mid-summer times without reaching capacity limits.

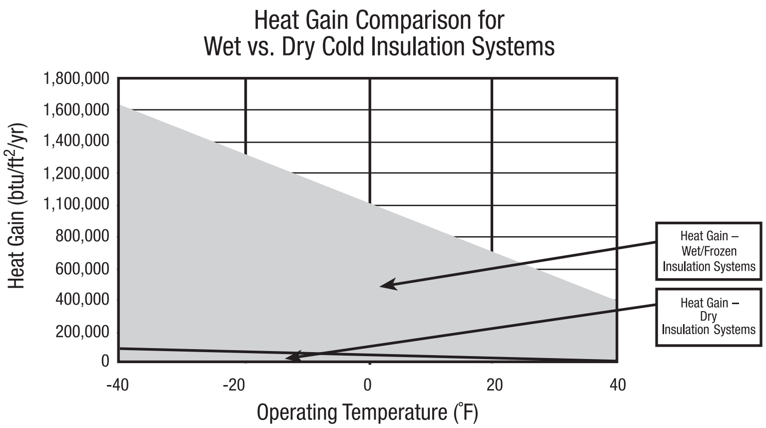



*Figure 4. One square foot insulated with 4 inches of insulation.*

## Maintenance: Still A Reactive Program

Another reason so much of industry's insulation systems remain damaged is the manner they are repaired. Insulation maintenance remains a very reactive program. Simply stated, this means that once it gets found, it gets fixed. The consequences of this type of maintenance are many.

- Usually only the most damaged, highly visible, items get fixed. As a result, every $1 that would have been spent to repair the insulation with minimal damage (e.g. sealant or jacket repair) will cost from $10 to more than $50. This does not help to stretch already reduced maintenance budgets!
- Each scope of work is small, leading almost invariably to low insulator work efficiency and high cost. The insulator must mobilize, secure all necessary permits, and get to the work site. This element of cost is essentially fixed, meaning it will take about the same amount of money to fix 3 feet as it would 30 feet of insulation damage in any one area. I have performed and seen studies that reflect from 20% to more than 300% less insulator work efficiency for work performed this way. Once again those precious maintenance budgets are getting strained!
- Many damaged areas are never even seen at all so are never fixed. Hard to see areas, such as congested, multi-tier pipe racks or the highest elevations of a facility are good examples. Personnel seldom travel there and have limited visibility. If they do so, needed insulation repairs are overlooked.
- Doing repairs in this manner makes it extremely difficult to identify the work that has been accomplished. As a result, a busy operations manager, who probably does not fully understand the benefits of insulation maintenance, sees money being spent without any real visible benefit. This makes a tempting budget-cutting target if money becomes scarce!

So, if insulation damage is not noticed, insulation maintenance is not viewed as important, the benefits are not well understood, and often the work that does get done is expensive, how can we improve it? The answer is to develop a planned or strategic approach to target and fix those areas of damage with the potential for the best benefit to the facility. It is packaged in such a way to deliver the best long-term cost. What follows is an explanation of ways to get it done.

- **Prioritize the facility.** Analyze the importance of the insulation systems for each section or process unit within your facility. For example, the catalytic cracker unit within an oil refinery is large, contains large equipment, piping, and vessels and utilizes some of the highest temperatures. Prioritizing this area will likely save the largest amount of thermal energy and money.
- **Prioritize the role insulation serves.** Which insulation systems are the most important and why? Is it process control, energy management improvement, freeze protection, personnel protection, or environmental emissions control? A chemical plant process unit manufacturing an aqueous chemical compound probably should be very concerned with freeze protection.
- **Define the scope.** Survey and quantify the necessary repairs, taking into account the quantity of damage, type of damage, and its physical location. This is the first step in assembling a work package that will yield the greatest benefit and lowest possible cost. A word of caution: do not assemble work packages any larger than you can reasonably afford to perform within a 2-year period.

Any period longer than this risks a work package that no longer reflects the needed repairs.

- **Package for geography.** Assemble the work according to specific geographic areas. This allows a crew of insulators to tackle a big enough job in any one area to make it worthwhile to get them there. The cost to mobilize a work group to and from any area can be from 10% to more than 20% of the total job cost.
- **Package for insulation damage.** If budget is an issue, consider performing repairs only on those insulation systems with damage that will yield the greatest benefit to the facility. Be careful with this one! If you split up the work in any one specific geographic area, you end up paying the work crew to come back time and again to perform work in the same area. Balance this need with packaging for geography, discussed above.
- **Develop specifications.** Insulation systems are not "one-size-fits-all" propositions. If you are only repairing a relatively small part of the insulation system, you probably want to consider specifying what is already installed, unless it is a hazardous, respirable fiber such as asbestos. However, if you are doing a large amount of work on any one system, consider:
  - The environment (exterior vs. interior, corrosive chemicals, temperatures, etc.)
  - The possibility for physical abuse, such as maintenance
  - Areas of regular maintenance (removable insulation systems may be needed)
  - Vibration
  - The reason for insulating (personnel protection, energy, etc.)
  - Cost and other factors.

  All these factors affect how well the insulation system will perform, how long it will last, and what it will cost. Time spent thinking about this will give you an insulation system that will last, resulting in the lowest long-term cost.
- **Get cost information.** Ideally, you should know what the work would cost prior to the start of job. A responsible contractor, particularly one with whom you already have a contract, can assist you in providing cost estimates for various jobs. This will give you valuable information in deciding how much you want to spend and how much value you think you will receive from the expenditure. Some companies believe that if you get a number of contractors together, show them the work, and request lump sum proposals from them, then you automatically get the best price. This is not always the case. Sometimes contractors may propose prices that some may think are higher than what the job should cost. Why? If it is a busy time for all contractors in a region, then manpower is scarce and the contractors may be stretched thin trying to do the work they already have. This condition often results in prices higher than normal. Again, a responsible contractor can give you estimates of what they think the job will cost, allowing you to decide to go ahead with the work, delay the work, or perform it another way.
- **Execute the work**. Consider the best way to perform this work. There are a variety of ways to perform it. Assuming you are considering using an insulation contractor, you can do it several ways. Several contractors can review the work at a pre-bid job meeting and submit lump sum bids. You can arrange to have the contractor perform this work on a "time and materials" basis, with the contractor charging for each hour of labor they spend, plus the cost of all materials and equipment used on the job.

  You could also have several contractors offer a "unit price" proposal in which the contractor proposes a fixed fee to perform a specific unit of work (e.g. per lineal foot or square foot for a specific insulation system installed on a specific surface). Each of these methods has been designed to perform cost effectively for the right kind of job under the right kind of circumstances.
- **Monitor the work.** The old saying goes, "You expect what you inspect," and that is true for insulation work. Thorough monitoring of the work for safety compliance, adherence to specifications, installation quality, scope completion, and schedule maintenance is critical to ensuring that the work has been performed according to what you requested and delivers the insulation system necessary to do the job you wanted done. Obviously, it is important for you to inspect the work. After all, no one else knows the facility like you do, along with the potential for hazards, and how to control them.

No one else knows what needs to be done better than you, and no one else looks out for your interest better than you do. However, an insulation contractor can be a valuable partner in making sure the work is done in a satisfactory manner. Look for a contractor that has a proven and demonstrated quality process system in place. A good contractor will be happy to explain in detail its quality program.

Managing your industrial facility's insulation work in this manner may be dramatically different than what was done before. However, this approach gives you, the facility owner, the best chance to fix the most important insulation repairs that will benefit the facility the most, at the lowest possible cost for a quality job designed to last a long time. You have the added benefit of performing necessary work to maintain your facility that almost always pays you back, continues to pay for years to come, is kind to the environment, and conserves precious natural resources.

# Specifying for Industrial Insulation Systems

*Gary Whittaker, Whittaker Materials Engineering Associates, LLC/National Insulation Association*

We have all heard the old saying, "No job is complete until the paperwork is finished." When it comes to insulation, this saying should be changed to, "No job should be started until the paperwork is completed." Specifically, no insulation job should be started until an appropriate specification has been prepared and agreed to by all involved.

For most of us, the thought of sitting down to read an insulation specification does not exactly compare with the excitement of cracking open the latest page turner from Tom Clancy or John Grisham, but a well-prepared and well-written specification is critical to the success of any project. In the National Insulation Association's National Insulation Training Program (NITP) we spend considerable time talking about specifications and the design process that supports the creation of an effective specification. We use the Process Industry Practices (PIP) (1) as the basis for industrial specifications and the published Architectural Computer Services, Inc. (ARCOM) MASTERSPEC® (2) as the basis for commercial specifications. For this discussion we will focus on the industrial side and will use the PIP Practices as the basis for showing how to create or interpret an effective specification so you can have your paperwork completed before the job starts. Please note that although PIP will be referenced throughout this article, it is certainly not the only effective method for effective insulation specification.

## What is a Specification?

What is a specification? According to the *American Heritage Dictionary*, it is a "detailed exact statement of particulars." True enough, but in the case of insulation it is far more than just a statement of particulars; it is how the designer communicates his intent to everyone involved, from the project manager to the installation contractor and the material suppliers. A good specification includes all the information the contractor needs to understand—what is to be insulated, the materials to be used, how they should be installed, and how they will be inspected. There is no such thing as a verbal specification. When an owner calls his local contractor and says, "Hi Bob, I have about 5,000 feet of pipe with a few valves and fittings that need to be insulated. I'd like you to come by tomorrow and take care of it. Just do the usual," he may have issued a verbal purchase order, but he certainly has not issued a specification, and he has left the door open to disaster. The contractor could interpret this to mean practically anything. An unscrupulous contractor might take advantage of the situation by using the latest in solid gold jacket, but the more likely scenario is that the owner will not get a system that is adequate for his application. The problems could be anything from an inappropriate insulation material to improper thickness.

In the case of inadequate thickness, the owner would end up wasting energy and could even have a safety problem if the jacket temperature turned out to be above the personnel protection temperature. The use of improper insulation material could result in energy loss, damage to the insulation, corrosion of the equipment, or even fire if a leaking chemical comes in contact with an incompatible insulation material. The lesson here is: don't just dust off an old specification and send it out. Each job should have a specification based on the specific project details.

By now you may be thinking, "Great, this guy thinks I need a 50-page specification to insulate 10 feet of pipe—typical engineer." A good specification does not have to be long to communicate the designer's intent in a clear and logical way. The authors of the PIP Practices had this in mind when they set out to create them. The end result is a series of text documents and datasheets that can be tailored to the needs of a specific project. A small project, such as 10 feet of pipe, might have just a few datasheets, while a large project could have many more. PIP was founded on the idea that standard specification formats used by everyone in the process industry would simplify the work of writing and reading specifications, and ultimately lower project costs.

In the case of insulation, the authors created a series of documents that cover engineering, materials specification, extent of insulation, detail drawings, and inspection.

Supporting these basic documents is a series of datasheets that are completed by the designer and read by contractors and material suppliers. The datasheets contain project specific information. The number of datasheets needed for a project depends on its size and complexity. At first glance, the PIP Practices are a daunting stack of paper, but with familiarity comes the realization that most of the PIP text is supporting information that does not change from project to project. After the text documents are learned, using the PIP Practices is an exercise in completing or reading datasheets.

## Design

The first step in any insulation project is design. This is the process of identifying the important parameters that must be addressed through the materials selection process. Much of the NITP is focused on understanding the design process and how it is influenced by both the physical properties of the insulation materials and the unique characteristics of the system being insulated.

Using the PIP Practices helps the specifier through the design process by requiring him to make choices. The first PIP document he must consult is INEG1000, "Insulation Design and Type Codes." This practice contains the type code definitions used by PIP, and the designer must choose the code that applies to his project. The codes describe the basic purpose of the insulation and include heat conservation (HC), process stability (PS), personnel protection (PP), prevention from freezing (PF), cold conservation (CC) and condensation prevention (CP). By choosing a type code, the designer selects the fundamental design for his project. Later in the process this choice will be used to help determine what PIP calls the "extent of insulation," which is nothing more than what will be insulated and what will not be insulated. The code will also become a part of the project documentation because it is included in the line code for each item shown on the project's piping and instrument diagrams.

The type codes help establish the basic reason for insulating, but there are many more criteria the designer must consider before choosing materials. We begin each NITP class by asking the students what they hope to learn. Perhaps the most common answer is, "I want to learn more about the different insulation materials and how they are used." In other words, how do designers choose from all those materials? One of the key points in design is to understand that there are many ways to solve a problem, all of which will work to some degree.

With training and experience, the designer learns to choose the best solution from among the many workable solutions. He does this by looking at each of the design criteria that apply to his project, prioritizing them and then choosing materials that best meet his priorities. Designers are human, so this process has a degree of subjectivity. Not all end users or designers will agree on what design criteria should apply to a project, how they should be prioritized, or which materials will best meet their needs. Occasionally, factors outside the design process intervene to force the designer to change his approach. For example, the project could be a rush job for which the optimum material is not available and cannot be obtained in time to meet the schedule.

So, what are some of these other design criteria and how do we sort them out? The way to start is to ask, "What will be insulated?" Is the item a vessel, a piping system, or machinery? The nature of the insulated item will sometimes dictate what material is best suited for the application. For example, suppose we are insulating a large machine that is complex in shape and our primary criteria is condensation control. Would it be better to use a rigid material that would have to be cut many times to conform to the complex shape, or would it make more sense to use a flexible material that could be easily fit to the curves? How this question is answered dictates which material is chosen, and not everyone gives the same answer.

After understanding what will be insulated, we need to know what the operating temperature will be. This is probably the most fundamental question of all because it establishes the appropriate type code and narrows the field of appropriate material choices. If the process is operating at 752˚F, all the organic materials automatically drop out of consideration. Likewise, if the temperature is minus 122˚F the field might be narrowed to closed cell materials.

The next question is, "What is the nature of the process?" By this we mean, what chemicals are being handled, and do they have any unique properties that might influence the design?

Often this relates to the flammability or reactivity of the process chemicals. Some industrial facilities that process flammable chemicals use only closed-cell insulation materials to prevent leaking chemicals from saturating a more absorbent material and causing a fire.

I once worked with a plant that originally insulated a highly flammable process using fibrous material because it was their standard material for the temperatures involved. This chemical had a habit of destroying gaskets and valve seals and the standard method of finding leaks was to look for fires. The chemical was absorbed by the fibrous insulation until enough was present to cause auto-ignition. We solved the problem by changing to a closed-cell product and providing drainage to prevent a dangerous build up of the chemical. We also worked to find compatible gasket and seal materials. However, the bottom line is that leaks happen and if the consequences of a leak could be severe, then the insulation design should help to minimize those consequences.

It is important to know the material of construction of the insulated substrate. Much has been written about corrosion under insulation (CUI), and there is a recommended practice (RPO-198) published by the National Association of Corrosion Engineers (NACE) (3) intended to reduce the likelihood of corrosion through the use of coatings.

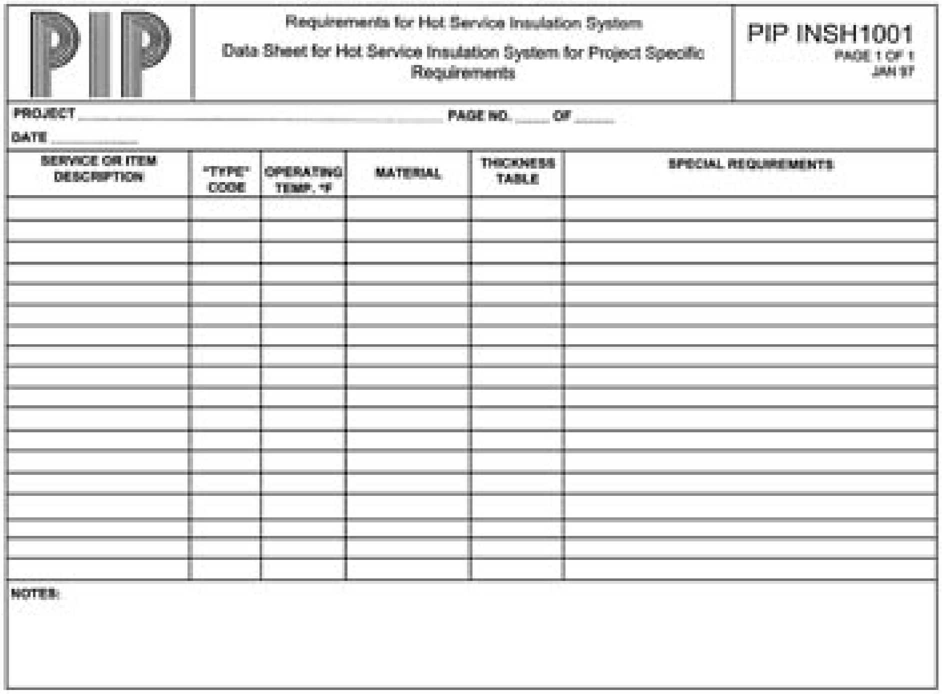
Not all end users follow the NACE recommendations, because in some cases, the risk of CUI is judged to be acceptable. In these circumstances, the choice of insulation material should be made to minimize the corrosion risk. For example, if a stainless steel line operating at 203˚F (a prime temperature for chloride stress corrosion cracking) is to be insulated and not coated, a non-absorbent material might be chosen in order to prevent the occurrence of conditions that could lead to corrosion. Some chemical companies take the “belt and suspenders” approach and use absorption-resistant materials along with following the NACE guidelines. All of this is dictated by the stainless steel substrate. This is just one example; other substrate materials present different problems that must be addressed by the designer.

The environment in which the insulation will operate influences many design choices. It is important to distinguish between indoor and outdoor conditions. If the insulation system is to operate fully exposed to the elements, then the choice of jacket material and how it is secured may be very different than if the system is inside a building. Outdoor systems generally require more robust jacket and sealing materials than indoor systems. Insulation is also exposed to people and it is this exposure that probably presents the greatest likelihood of damage. It is a fact of life in all chemical plants that insulated pipes and vessel tops make great ladders and platforms. Physical abuse can be addressed by choosing damage resistant materials. A solution many in the chemical industry use is to select a dense insulation material, such as calcium silicate or perlite, for the top surfaces of pipes and vessels that are likely to be damaged.

Material selection is clearly a major part of the specification process. An equally important part of the design process is deciding exactly what parts of the piping and equipment will be insulated. PIP refers to this as the extent of insulation and defines it as, “those items or systems that are to be insulated under requirements of a given type code.” Notice that the extent of insulation is directly related to the type codes that were chosen. The extent of insulation for heat conservation would be different than for personnel protection or cold conservation. PIP includes recommended extent of insulation datasheets for hot and cold service: INSH2001[1] and INSC2001. In a matrix format, the datasheets list many equipment items and with a simple “yes” or “no” they determine whether insulation should be applied to meet the desired criteria. Each datasheet also has blank columns and rows to allow the designer to tailor the extent of insulation to his specific project.

The final step in design, after choosing the materials and determining the extent of insulation, is calculating the appropriate thickness. Thickness should be based on the specific details of the project and the primary design criteria. For example, in many cases the thickness required for personnel protection will be different than that required for optimum heat conservation.

[1] Please refer to the Editor’s Note on page 37 for explanation of the PIP datasheet identification system mentioned in this article.



| PIP | Requirements for Hot Service Insulation System<br>Data Sheet for Hot Service Insulation System for Project Specific Requirements | PIP INSH1001<br>PAGE 1 OF 1<br>JAN 97 |
|---|---|---|

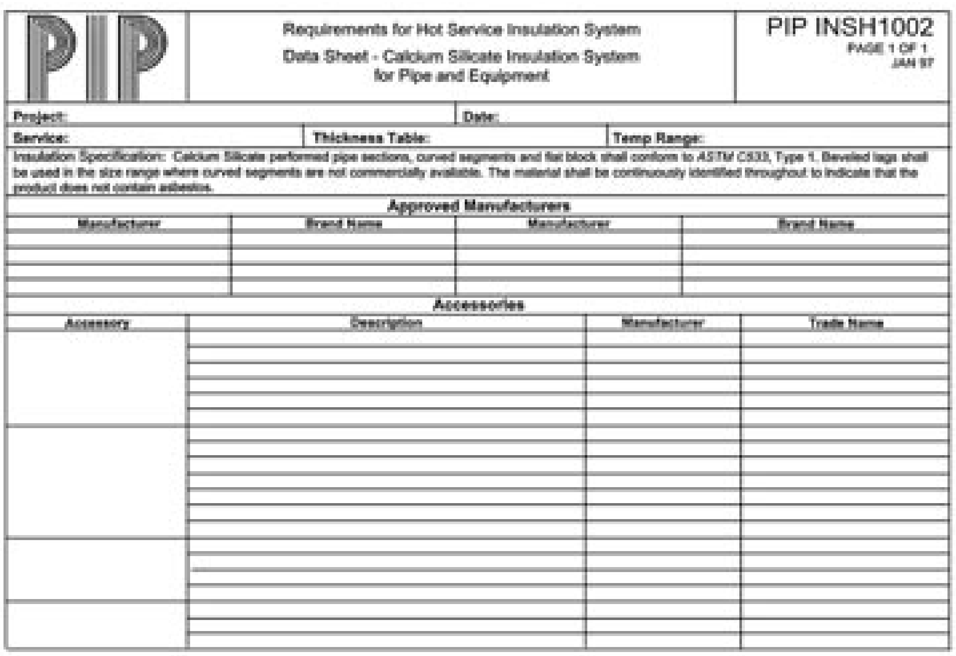
PROJECT ______ PAGE NO. ____ OF ____

DATE ______

| SERVICE OR ITEM DESCRIPTION | "TYPE" CODE | OPERATING TEMP. °F | MATERIAL | THICKNESS TABLE | SPECIAL REQUIREMENTS |
|---|---|---|---|---|---|

NOTES:

*Figure 1. Datasheet for hot service insulation.*



| PIP | Requirements for Hot Service Insulation System<br>Data Sheet - Calcium Silicate Insulation System for Pipe and Equipment | PIP INSH1002<br>PAGE 1 OF 1<br>JAN 97 |
|---|---|---|

Project: Date:

Service: Thickness Table: Temp Range:

Insulation Specification: Calcium Silicate performed pipe sections, curved segments and flat block shall conform to *ASTM C533*, Type 1. Beveled lags shall be used in the size range where curved segments are not commercially available. The material shall be continuously identified throughout to indicate that the product does not contain asbestos.

Approved Manufacturers

| Manufacturer | Brand Name | Manufacturer | Brand Name |
|---|---|---|---|

Accessories

| Accessory | Description | Manufacturer | Trade Name |
|---|---|---|---|

*Figure 2. Datasheet for calcium silicate.*

The North American Insulation Manufacturers Association (NAIMA) has published the 3E Plus® software program to calculate insulation thickness. 3E Plus is accepted as the standard method for determining insulation thickness. The 3E Plus user must provide project specific information on the process and the materials selected to determine the proper thickness. If economic thickness is determined to be considerable, project specific economic data must be supplied and it is unlikely that using data from past projects will produce an accurate answer.

## Documentation

At this point, the designer has established design criteria, determined the extent of insulation, and calculated the required thickness. The next step in the process is to write it down. PIP provides a series of datasheets that are used to communicate the decisions made in the design process. The first are tables used to describe the system design, INSH1001 for hot and INSC1001 for cold. Each row in the first column is used to record an item or system to be insulated, for example, "10 feet of pipe." Next are columns to record the type code, operating temperature, insulation material, thickness table and finally a column to record special requirements.

The designer could sit down with an equipment list or piping line list and record the insulation material, type code, thickness table, and any special requirements for the entire project in one table. It could be for 10 feet of pipe or 10 pressure vessels. Figure 1 is an example INSH1001.

The next datasheets provide detailed information on the selected materials and the accessories that have been chosen to install that material. There is a material datasheet for each major material covered by PIP. Figure 2 is the PIP provided sample for calcium silicate. There are spaces to identify the project and list the approved manufacturers for all the accessory items. INIH1000 and INIC1000 are a collection of detailed installation drawings that describe the PIP preferred installation methods. The specifier selects only the drawings that apply to his project for inclusion in the package.

Finally, there are datasheets, INSH2002 and INSC2002, that are used to list all of the documents to be included in the package—the datasheet datasheets. It may seem strange to have a datasheet for datasheets, but in a big project that might include many datasheets, it is helpful to have them all recorded in a single location. Each of the datasheets has a text document that provides supporting information and should be supplied with the datasheets, at least until the contractor has learned the system. For example, INSH2000, "Installation of Hot Service Insulation Systems," provides text information that expands and supplements the installation information shown on the detail drawings.

At this stage the process is almost complete. The designer has established and prioritized the design criteria, selected materials, calculated thickness, determined the extent of insulation, and completed the datasheets necessary to communicate the information. All of this is assembled into a package for transmittal to the contractor and material suppliers. For a project that has just 10 feet of pipe, the package could be as small as two datasheets, a drawing, and the supporting text documents. If the contractor is familiar with PIP and already has the text documents and drawings, then all that is really needed are the two datasheets. If it is a big project with many pipes and vessels, then the package will be larger.

## Inspection

If you have followed the process, you now have a good specification. But does a good specification guarantee a good installation? In a perfect world it would, but unfortunately we do not work in a perfect world. Inspection is a key part of the insulation process; it is important to determine what inspections will be required and what results are acceptable. Without acceptance criteria the contractor does not know to what standard he will be held and the inspector does not know how or what to inspect. PIP has created an inspection standard, INTG1000, which provides an inspection checklist for use by both the inspector and the contractor. The inspection practice should be included in the specification package, which should be discussed in detail with the owner, contractor, and inspector before the job begins, preferably in a pre-job conference. There should be agreement between all parties about the specification requirements and about how discrepancies will be handled. There should never be arguments after the job has started about what the specification requires.

Finally, does the PIP Practices have to be used to write a good specification? Clearly the answer is no. PIP is an example of how an industrial specification package can be assembled. It contains all the critical elements needed to establish the basic design criteria, to choose the insulation materials, to determine thickness, and to communicate all the important information to everyone involved. Many companies, end users, and engineering contractors use unique specification documents to effectively carry out the same mission as PIP. While they use different formats, the good ones all communicate the same basic information.

In summary, any good specification communicates why we are insulating, what we are insulating, with what materials, and how they are to be installed.

## References

1. Process Industry Practices, *www.pip.org*.

2. Architectural Computer Services, Inc., ARCOM MASTERSPEC®, a product and registered trademark of The American Institute of Architects, *www.aia.org*.

3. National Association of Corrosion Engineers, Standard Recommended Practice RPO198-2004, *The Control of Corrosion Under Thermal Insulation and Fireproofing Materials—A Systems Approach*, reaffirmed March 2004, *www.nace.org*.

Editor's Note: The PIP "Insulation Document Use Guideline," (INGG1000), 1997, defines the eight-character datasheet identification system as follows:

The first two characters designate the function team. For example:
IN - Insulation

The third character is the PIP section designator:
G - General
E - Engineering Design
I - Installation
S - Specification
Q - Quality Assurance

The fourth character designates service category:
A - Acoustical Insulation
C - Cold Insulation
D - Dual Temperature Insulation System
F - Fire Proofing Insulation
G - General
H - Hot Insulation

The last four characters designate numerical sequence of the datasheets.

Please see *www.pip.org* for more information.

## Boiler and Combustion Safety What You Don't Know CAN Kill You!

*John Puskar, Combustion Safety, Inc.*

An industrial explosion kills six in Michigan, another kills four in Virginia, and the list goes on. These are only two very tragic, recent national headlines. The November 2000 *National Fire Protection Association (NFPA) Journal* (1), reported that catastrophic fires and explosions cost industry more than $2 billion in 1999. This made 1999 one of the worst years for industrial fire safety in recorded history. These statistics say nothing of the thousands of smaller events that occur and go unrecorded, such as boiler fires, process oven failures, and the burns and injuries from these events. Unfortunately, society and individual companies usually act on these issues only when some very large and tragic event occurs.

This paper hopes to provide a means of encouraging combustion equipment safety action at your facility before it is too late. I hope to raise your awareness about this area of safety that few people know about simply because it is complicated and misunderstood. Combustion equipment safety is critical to the daily operation of all facilities and the safety of every employee. This paper will help you understand how to protect your employees from combustion-related incidents involving fuel-fired equipment (boilers, ovens, pressure vessels) before you end up a headline.

For the non-combustion person, this paper reviews basic gas train safety controls and concepts, and provides an understanding of the most common problems we have found through our inspections of more than 2,000 gas trains, the training of more than 1,000 skilled trades people, and the development of corporate combustion equipment safety programs for some of the world's largest companies.

Most facilities do not have personnel properly trained in combustion equipment maintenance, start-up or shutdown procedures, and/or equipment operations. Most sites also do not follow proper interlock and safety testing guidelines even though they are mandated by law. Boiler safety laws passed by a number of states hoped to help this. Boiler inspections are mandated to be carried out in states and municipalities that have boiler safety laws. These are called jurisdictional inspections. In most states these laws call for inspecting, but not testing, only the pressure vessel part of each boiler system. In 26 states American Society for Mechanical Engineers (ASME) CSD-1 codes have been adopted that mandate actual operational combustion safety systems training. In these states jurisdictional inspectors ask to see evidence of this gas train and safety interlock testing. However, it is beyond their scope to do any of this testing.

### "But It Was Just Inspected!"

This is a desperate attempt to suggest that everything humanly possible was done to avoid a catastrophe. People (i.e., owners or operators) think that a jurisdictional boiler inspection is the magic bullet or armor shield, when in fact in many cases it is not. Very few realize what a typical mandated jurisdictional inspection truly is and is not. Many large industrial clients are realizing that these mandated inspections are not enough to protect their most important assets—their employees' lives. Some of these companies now have combustion equipment safety programs that go well beyond minimal legally mandated requirements. These inspections include a detailed check of their combustion systems. This usually includes an analysis for code compliance, installation deficiencies, interlock testing, screening for maintenance practices that can impact safety, and assess technological advances to improve safety.

*Photo 1. This equipment, in this condition, has been approved to operate "as is" by current jurisdictional inspection practices.*

## Grandfathering Old Equipment

Jurisdictional inspectors often have their hands tied when it comes to what they can ask someone to do. Often what they are inspecting for is limited by the exact letter of the law. For example, in many cases they can only evaluate equipment for its code compliance when it was installed.

*Photo 2. During most inspections archaic equipment like this 60-year-old boiler does not typically get screened for safety upgrades to firing controls.*

Typically, there is no screening for how far away from the most recent codes the old "grandfathered" technology is. This kind of inspection sometimes means that you could be "technically" in compliance with archaic and antiquated equipment that is 50 years old or more. This could be equipment that requires many manual steps to operate safely and puts your site at serious daily risk of improper manual start-up or shut-down. You could walk away from this kind of inspection being technically "in compliance," but nowhere near the current codes level of safety or state-of-the-art for the industry.

Consider also that unless you are in a state that adheres to ASME CSD-1 codes, inspections rarely address gas trains and/or fuel system issues. Interlock testing is usually assumed to be a responsibility of the owner, yet interlocks are among the most vital safety components for ensuring that your systems work safely.

When it comes to process ovens, space-heating equipment, furnaces, heat-treaters, and other industrial process users, there are very specific guidelines for protection, but very few people know about them. Often these are custom pieces of equipment with safety controls that are assembled from components. Unlike boiler systems, there are no jurisdictional programs to inspect or test non-boiler, fuel-fired equipment.

## What is Interlock Testing? Why Does It Matter?

Burning fuels can be useful as long as it is with a controlled process. Control means that combustion takes place where we want it, when we want it, and at the rate we want it.

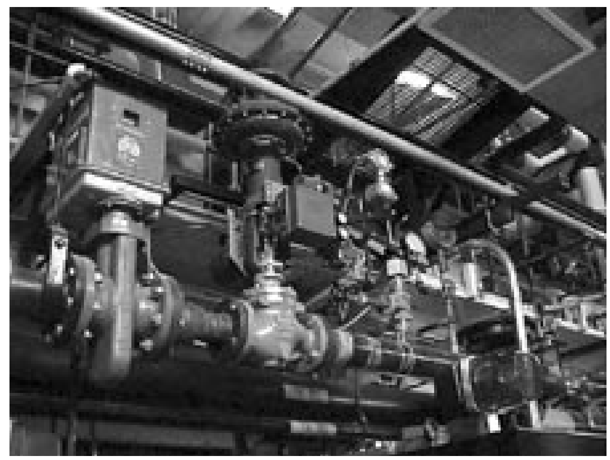


*Photo 3. Typical gas train with safety interlock components.*

The complicated-looking series of valves, wires, and switches that comprise the gas train installed on gas-fired equipment is what attempts to do this.

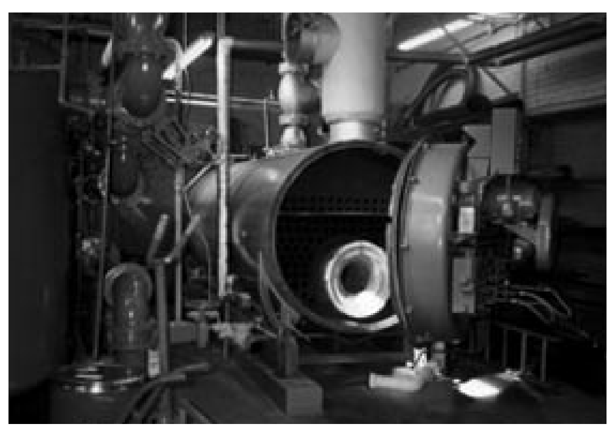


*Photo 4. Most inspections today are only annual at best, and only related to pressure vessels.*

Gas trains help us to keep gas out of the combustion chamber when no combustion is taking place through a series of tight, specially designed shut-off valves that are spring-loaded to close. These are the safety shut-off and blocking valves. Larger gas trains require dual valves, and some also have a vent between these valves for added safety. Your specific configuration depends on your insurance and local code requirements.

Gas trains also have a number of components that ensure that safe light-offs take place and that shutdowns occur immediately if anything goes wrong during the operation of the equipment. They do this with a series of pressure switches that detect too high or too low gas pressures to the burner.

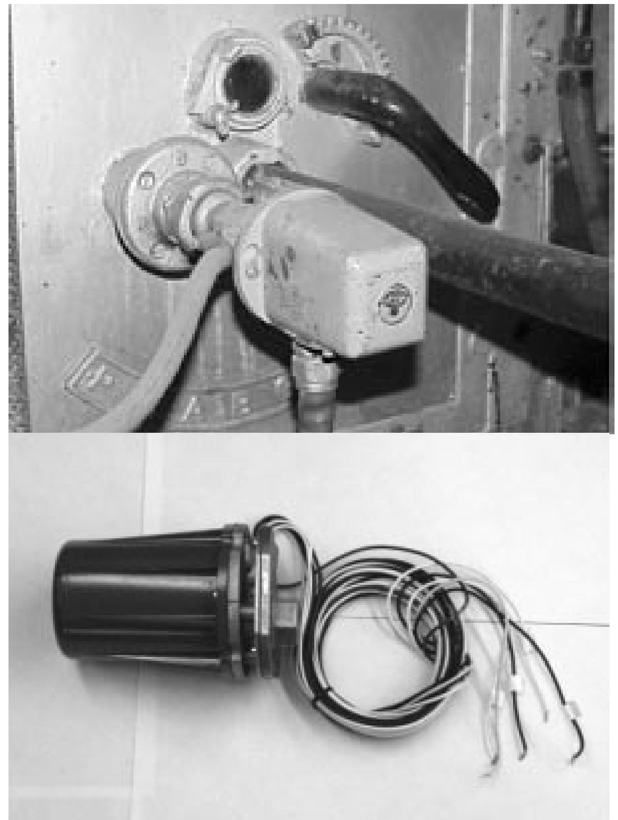
*Photo 5. Typical high/low gas pressure switches to verify gas pressures are in the proper range.*

Typically, they also have switches to make sure that airflows are correct for purging residual combustibles prior to light-off and that airflow is correct during operation.

Usually, flame-sensing components exist to make sure that flames are present when they are supposed to be present and not present at a wrong time.

Other components for sensing that the fuel valve is at low-fire position prior to light-off may be present, along with furnace pressure switches, high temperature limits, and/or water level cut-outs (depending on the type of equipment).

All of these components are logically linked or interlocked to a burner management system



*Photos 6 and 7. Typical flame scanners that monitor flame conditions.*

controller (BMS). The BMS is the brain that supervises and sequences all of the light-off efforts and watches as the combustion processes take place. A BMS manages the timing and adequacy of the purge prior to light-off and the time intervals allowed for lighting pilots and main flames.


*Photo 8. The burner management system is the brain that monitors/directs safe firing and operations.*

By law, all of this equipment should be checked on a regular basis, but with maintenance budgets among the first to be cut, proper checkouts and testing are seldom performed. Codes and manufacturers define what these frequencies are for different types of equipment. Frequencies of required testing vary from daily for some items such as observing flames (assuming you know what to look for), to annually for some block-and-bleed valve tightness testing requirements. It is in this frequency area that we find many problems in industry today.

We typically find that no one is aware of regular testing requirements specified by codes. In most cases we find that sites do some level of testing semi-annually or annually. The level of comprehensiveness varies, depending on who is in charge and that person's knowledge of the equipment or systems.

## Where Did the Codes/Industry Protections Originate?

Before you can understand how to protect yourself and your facility, it is important to cover a little background. In the early 1800s, boilers and pressure vessels were at the root of many catastrophes. This created new industries, laws, and infrastructure (from the technical community) to protect the public. This has included the hard work and effort from thousands of dedicated jurisdictional inspectors. They have truly been the backbone of this effort and it has worked very well. Pressure-vessel related incidents have dropped dramatically since that time. These groups have done a wonderful job through the years and have no doubt saved thousands of lives in the process.

Later, additional emphasis was placed on having safe standards for the use of fuels, such as natural gas. Once again, the gas industry, fire protection groups, and insurers came together to identify codes/laws for safe fuel handling and special combustion systems protection. Again, the effort worked. Incidents dropped dramatically.

I want to take you through two equipment situations that we face every day, and describe how and where a plant can get into trouble when it comes to combustion equipment safety, even with all the existing laws, codes, and checks and balances. Let's look at the case of a new facility being built and this same facility after it has been in operation for a number of years.

## New Facility

Consider a new facility being built to include gas-fired process equipment and a heating system that includes a boiler.

The project could have been conceived and directed by someone in your corporate staff. It may give you an underlying sense of confidence to think that degreed professionals designed the facility. The plans were then most likely reviewed by a number of people, including the city's building department, the local fire department, an architect, and an insurance company representative. A licensed contractor probably did the equipment installation. You may expect to rest peacefully knowing that probably a dozen skilled professionals have, no doubt, reviewed and blessed everything about the installation.

But all may not be well. Here are some disturbing issues about this scenario.

### *City Building Departments*

City building departments often farm out the review of plans to architects or engineers since they usually do not maintain staff for large projects. Typically, they look for very significant local code related issues. This is most likely not a detailed examination of how your system was selected or installed and it has nothing to do with how it is operated.

They will most likely send an inspector out to see your equipment after it is installed. The inspector is probably a retired tradesman. He will certainly know about residential work because it is probably 75% of what he sees. It is very unlikely that this person would know much about boilers or industrial process equipment.

### *Corporate Project Engineering Staff*

I was a corporate staff engineer for a major oil company. We managed projects. We relied on specialized consultants for giving us advice on equipment selections. In most cases the firms we used relied on vendors to tell them what they needed. This information was translated to drawings and a conceptual specification was generated. Rarely did this level of design include detailed gas train piping drawings and wiring schematics. In most cases this level was not possible to develop until a specific equipment vendor was selected.

If the design process works correctly, a selected vendor provides detailed drawings for insurance approvals. This step is then followed by a very detailed and thorough commissioning at the site to verify that all was installed and working properly. If these steps happen, then you are likely to be starting off with a very safe site.

#### *Project Architects*

Architects receive little or no formal training in building mechanical or combustion systems. It is simply not in their scope. Most likely they will rely on the city's code officials, a hired consulting engineer, and/or a contractor or vendor to provide mechanical or combustion knowledge.

#### *Project Managers*

Project managers are (usually) general contractors hired to be schedule and budget people. Once again, it is not typically in their scope of work to spend much time or effort focused on meeting fuel, combustion, or boiler safety codes. They usually assume others address these issues.

#### *Insurance or Mandated Jurisdictional Inspectors*

In many cases, jurisdictional inspectors have their hands tied. They are only supposed to review pressure vessel and piping issues including air tanks, water tanks, and boilers. They are not supposed to focus on system issues such as the gas piping at the site, the gas train component settings, control logic, and/or the burner flame pattern.

#### *Local Fire Departments*

It would be rare for a fire department to have a boiler or gas equipment expert on its staff. Most fire departments spend the bulk of their time on fire-fighting technologies and issues, such as sprinklers, firewalls, and alarms.

So where does that leave us? It makes for a case where many people may have looked at or have been involved in the new combustion equipment installation, yet no one may have specifically been focused on the combustion safety or fuel system related issues.

### OK, So Now It's Installed, But…?

Assume that you ended up with a properly installed and commissioned system. Who is now qualified to operate and maintain the equipment? The staff, consultants, and vendors have now all left your site.

Operations and the human element are the biggest safety issue. The National Board of Pressure Vessel Inspectors (2) statistics for boiler incidents from 1992 through 1998 show that 40% of all deaths, 37% of all injuries, and 31% of all accidents are caused by human error or poor maintenance.

The day after everyone leaves and they have blessed your site, just one person and a well-placed screwdriver can reduce your building to rubble.

Codes offer very little specific direction in this area. The ASME boiler code in Section VII, Subsection C2.110 (3) says "Safe and reliable operation [of boilers] is dependent…upon the skill and attentiveness of the operator and the maintenance personnel. Operating skill implies knowledge of fundamentals, familiarity of equipment, and a suitable background of training and experience. Regularly scheduled auto-manual changeover, manual operation, and emergency drills to prevent loss of these skills are recommended." This kind of training, particularly the mock upset, troubleshooting, or emergency training, may be ignored in most situations we see, even though it is very important. With boilers, there are at least licensures and jurisdictional inspection certifications required. However, this only exists in 26 states. Additionally, many municipalities require no licensures or inspections.

Other codes not related to boilers, such as NFPA 86 1-5.1 to 1-5.5, (4) require that "all operating, maintenance, and appropriate supervisory personnel shall be thoroughly instructed and trained under the direction of a qualified person(s)…and shall receive regularly scheduled retraining and testing." This code also states that operator training "shall include the following, where applicable: combustion of fuel-air mixtures, explosion hazards, sources of ignition including auto-ignition, functions of control and safety devices, handling of special atmospheres, handling of low-oxygen atmospheres, handling and processing of hazardous materials, confined space entry procedures, and operating instructions."

Many sites assume training happens on-the-job in an informal sense. To these companies, it is information that gets passed on from person to person over coffee or in between baseball scores.

## Somehow We're Running Safely, But...

Deterioration and aging happens over time. Dirt accumulates in parts of the burner from the combustion air taken in. Maybe the boiler water treatment has not been stellar, and sludge has accumulated in places. Once in a while, when you stand in a certain place you may smell gas. Maybe there are also age or operationally related situations. Here are some examples.

- During rounds you see what appears to be a slight wisp of steam coming from a small crack near the manhole cover of the boiler mud drum.
- You keep getting low water alarms on a regular basis.
- There appears to be a blackish haze coming from one of your boiler stacks.
- You notice paint peeling from the sidewall of one of the boilers.
- The feedwater line appears to regularly sway where it did not before.
- During a trip up to the roof you smell gas.
- One of the relief valves seems to be weeping.
- During boiler light-offs you hear what sounds like a loud "whomp."

These are all examples of possible operational or maintenance issues that could spell trouble for you and your site. Believe it or not, codes do call for provisions that make for very specific and regular maintenance of certain size boilers and their components. These specific requirements do not cover all boilers. Another problem is that only about half of the states and even fewer municipalities have adopted these as part of their local laws and requirements.

When it comes to gas-fired equipment other than boilers, the codes do not identify specific maintenance frequencies. The guidelines instead call for manufacturers' recommendations to be followed. Some manufacturers would have you testing yourself out of business. It is hard to know what is really practical and useful.

*Photo 9. People get creative to defeat safety controls. Here a Popsicle® stick is stuck into an air switch to force it always open.*

This is where the trouble starts. When was the last time you walked into a facility that had been in operation for some time and saw someone with comprehensive interlock testing documentation? We rarely find personnel armed with required component set points, accurate wiring diagrams, and documentation from a manufacturer on testing frequencies and test methods.

If you are in the norm, and you are not doing recommended interlock testing, or do not even know that there is such a thing, you need to change your culture and practices immediately.

## Gas Explosions Can Be Avoided: Here's How

Natural gas and combustion equipment safety continues to be a black art among industrial users. Most sites have personnel who are inadequately trained in the safe start-up/shutdown of equipment, daily operations, or its proper testing and maintenance. Our firm's survey of industrial users found that less than 10% actually perform manufacturer or code recommended preventive maintenance including testing of critically important safety interlocks. The combination of these two circumstances can spell disaster and it has in numerous facilities. When assessing your site's circumstances, consider the following.

1. **By far, most of the explosions and fire**

**incidents are caused by human error.** All of the safeties and interlock equipment in the world will not help if you attempt to short-circuit or jumper-out safety controls. There is no possible substitute for proper training.

2. **Start-up and shutdown are the biggest risks.** You need well-written and clear procedures to make the process very simple and straightforward.
3. **Make sure that you do regular and complete interlock testing.** Jurisdictional inspectors cannot be at your facility every day. Combustion safety and testing needs to be part of your organization's culture.

It is going to take a great deal of effort and change in your company's culture. In the beginning, you'll probably get a lot of the same old, "Gee, we've been doing it this way for years" stories. Our clients have found the first year of having a comprehensive testing and training program to be painful. For these companies, it has taken a lot of effort and faith to start implementing fixes and upgrades on equipment that works, is seemingly fine, but is nowhere near current codes or state-of-the-art in protection.

The bottom line is that implementing comprehensive combustion equipment safety programs has saved lives. We have helped to identify and correct nearly 1,500 failed interlocks and/or critical safety system failures over the past two years. The tides have now turned from aggravation and suspicion among employees to gratitude and thanks.

It is very satisfying to see more and more major companies subscribing to our model checklists. This is proof that there is a valid need and true benefit created by this process.

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# Cash Flow Impacts of Industrial Steam Efficiency

*Christopher Russell, Alliance to Save Energy*

Steam systems represent significant value in manufacturing facilities. The sheer volume of energy consumed by U.S. manufacturing makes this evident: 16.5 quads[1] of energy are consumed by industry as fuel; 45% of that is used to raise steam. Add to that the fuel used by steam systems in institutional, commercial, and military settings, and the total energy required by all steam systems (about 9 quads) represents approximately one tenth of total U.S. energy demand (98 quads). With energy prices in the neighborhood of $5 per million British thermal units (MMBtu) this adds up to $45 billion for just the fuel cost of raising steam (1) (2).

At the facility level, steam remains a ubiquitous yet underappreciated utility. While steam performs a countless variety of thermal transfer tasks within the majority of manufacturing industries, it is widely perceived as a "support" utility. In other words, steam is considered a power source subordinate to process lines that are the real focus of manufacturing activity.

Steam system savings potential is within practical reach. One comprehensive study of 66 major steam plants found that 12.3% of fuel consumption, totaled over all plants, was avoidable (3). The overall payback for these opportunities equaled 1.7 years. But, while this volume of savings was identified, the actual implementation rate of enabling projects represented only 3.9% of fuel consumption (i.e., only one third of the opportunities were implemented). An additional point worth noting is that only about half of the opportunities identified required capital investment; the balance required only operational or behavioral changes.

Why do companies forfeit additional earnings? Many companies simply fail to capture the full range of opportunities that occur where financial and engineering priorities intersect. Steam and other energy efficiency proposals may be stalled by a variety of corporate barriers—indifference, technical incompetence, capital budgeting procedures, and investment biases are but a few examples. Financial criteria are paramount—as must be the case for any profit-motivated enterprise. The challenge is for plant superintendents to advance steam plant optimization not simply as engineering projects, but as effective contributions to financial performance.

## Impacting Business Through Steam Efficiency

The actions that provide steam efficiency are training, proper technology selection, adequate maintenance, and disciplined monitoring of fuel and other system inputs. Data describing plant operations provides a window on system performance. Because of system optimization, anomalies are more often detected before they become failures that shut down the plant or injure employees. As downtime is reduced, so too is the need to run overtime shifts to "catch up" to production targets. Combustion emissions decline proportionately with fuel consumption. In addition, optimized plant equipment increases productivity. When thermal losses are contained, a greater portion of boiler capacity can be directed to productive functions, enabling the plant to extend production runs or perhaps even begin new product lines.

## Return on Investment

Global competition and decentralized corporate structures provide formidable challenges for manufacturing industries. Cost control is especially important for producers of bulk chemicals, grains, oils, paper, and other commodity products, which cannot be easily differentiated from competitors' output. Decentralized corporate structures give rise to virtually independent profit centers within a corporation. This fosters internal competition among profit centers in the allocation of investment capital. The overarching measure of success within the manufacturing corporation is return on investment (ROI), which becomes a benchmark for deciding 1) how well managers are employing currently invested capital, and 2) which profit centers should get new investment capital. If steam plant superintendents are to be successful in securing capital budget funds, their proposals must clearly demonstrate effective contribution to the corporation's return on investment.

[1] One "quad" is one quadrillion British thermal units (Btu). Stated differently, one quad is $10^{15}$ Btu.

The ROI measurement is derived from these financial elements:

$$\frac{\text{Net Operating Income}}{\text{Sales}} \times \frac{\text{Sales}}{\text{Average Operating Assets}} = \text{ROI} \qquad \textit{Equation 1}$$

*where:*

$$\frac{\text{Net Operating Income}}{\text{Sales}} = \text{Margin}$$

*and:*

$$\frac{\text{Sales}}{\text{Average Operating Assets}} = \text{Asset Turnover}$$

*so that:*

$$\text{Margin} \times \text{Asset Turnover} = \text{ROI} \qquad \textit{Equation 2}$$

A few concepts in this figure are worthy of additional discussion. Net operating income represents earnings before interest and taxes. It is what remains of sales revenue after deducting operating expenses, which include the cost of goods sold, operations and maintenance, administrative costs, selling expenses, and depreciation.

Average operating assets are the mean dollar value of all assets held over the course of an accounting period (usually a year).

Margin is the ratio of net operating income to sales revenue. As such, it is expressed as a percentage and can be interpreted as the "cost-price efficiency" of a profit center. Margin may be most useful for measuring sales and marketing performance. However, margin does not incorporate asset utilization, so it is only a partial measure of overall manufacturing performance. Keep in mind that manufacturing involves amortized plant assets, which incur interest and carrying costs that accrue daily, regardless of production volume. It therefore makes financial sense to maintain asset utilization rates as close to 100% as possible.

Asset turnover is margin's complement. Asset turnover expresses sales revenue as a multiple of the value of assets that produced that revenue. In effect, asset turnover is a measure that compares the relative revenue-making effectiveness of two or more plants, or to track one plant's performance over time. When a profit center's margin and asset turnover are multiplied together, the product is return on investment. Therefore, ROI is a simultaneous measure of the profit center's control of expenses as well as its utilization of production assets.

Why must margin and asset turnover be used together? Think of these analogs: margin is to speed as asset turnover is to time. Taken singularly, speed and time are of limited interpretation. But multiplied together, speed and time describe distance, or the product of travel. Similarly, margin times asset turnover describes the financial product of a manufacturing facility.

A review of the elements in Figure 1 reveals that there are five ways, broadly speaking, to increase ROI:

1. **Increase product price.** This sometimes applies to consumer goods, particularly when they can be marketed as "green" or environmentally friendly. In this case, the manufacturer's effort to optimize energy use also reduces emissions output, thus fulfilling its environmental responsibility. This is not realistic for bulk commodities, which have prices set by the market (instead of the manufacturer), and are sold in business-to-business markets, which, aside from any compelling regulation, have little regard for altruistic intentions.
2. **Increase production volume or number of product lines.** If the market will accept the plant's additional output, fine. But does the plant have the capacity to produce more output? Steam system efficiency can recapture thermal resources that were lost to leaks, radiant losses, and poor condensate recovery, and apply that load to new production initiatives.
3. **Reduce operating expenses.** The impact of steam optimization in this instance should be obvious—become energy efficient to spend less on fuel. There are additional impacts:
   a. Plant optimization helps to preclude downtime. In turn, production schedules become more predictable. This gives the manager tremendous leverage when negotiating with fuel marketers. Fuel is cheaper when purchased in fixed-priced contracts, so predicable consumption allows a greater proportion of fuel to be acquired in this manner. This avoids the bother and expense of purchasing fuel in spot markets, which may happen when plants put on extra, unscheduled shifts to compensate for downtime.

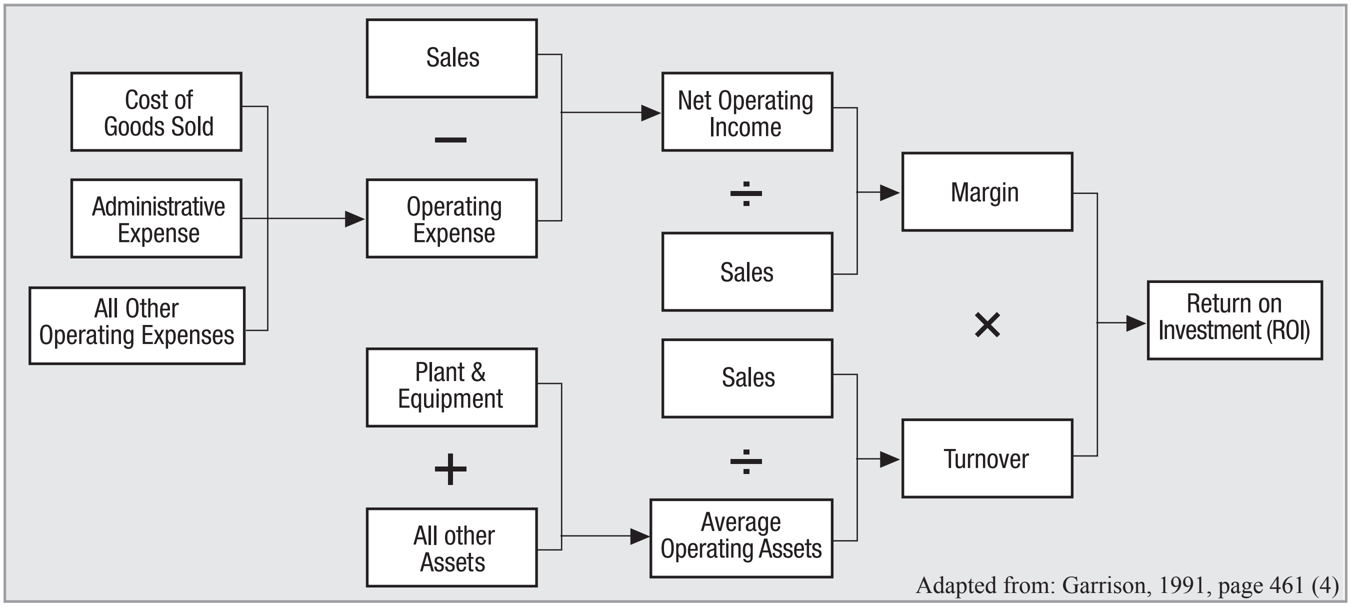



*Figure 1. Elements of manufacturing return on investment.*

b. Similarly, overtime salaries are avoided.

c. The optimized plant is safer, thanks to more diligent monitoring and maintenance. This is reflected in a clean boiler log, which is leverage for reducing hazard insurance premiums.

d. The same actions reduce the exposure to penalties imposed by safety and emissions regulations.

e. For some processes, scrap reduction is achieved through the same actions that enable energy efficiency. Insufficient heat transfer can spoil work in process, rendering a greater waste of raw materials. For example, improved insulation of steam distribution lines and the reduction of scale build-up in pipes both ensure that heat transfer is achieved at or near system design specifications. Stability of operating parameters reduces waste, as reflected in lower direct material costs.

4. **Reduce asset holdings.** This is an option frequently favored by corporate leaders whose expertise is more financial than engineering-based. ROI embodies the "do more with less" concept when attempts are made to reduce the volume of assets employed per unit of sales. Concurrent to this approach is the aversion to investing in new assets unless it is absolutely necessary. This is one reason why industry still employs many boiler assets that are decades old. True, as assets are reduced, ROI is increased primarily in the short run.

5. **Reduce the downtime of asset holdings.** The price for avoiding new assets is to endure the failure of old ones. Corporate leaders can maintain ROI by avoiding asset additions, but eventually the downtime imposed by failing assets begins to defeat this strategy. Plant optimization achieved through applied energy efficiency can only support the manager's adherence to production schedules. It is worth repeating that assets impose the same carrying costs whether they are operable or not, so financial performance is improved by moving asset utilization factors as close to 100% as possible. From a financial perspective, plant optimization permits greater yield from assets in place.

## Putting It All Together: Impacts on ROI

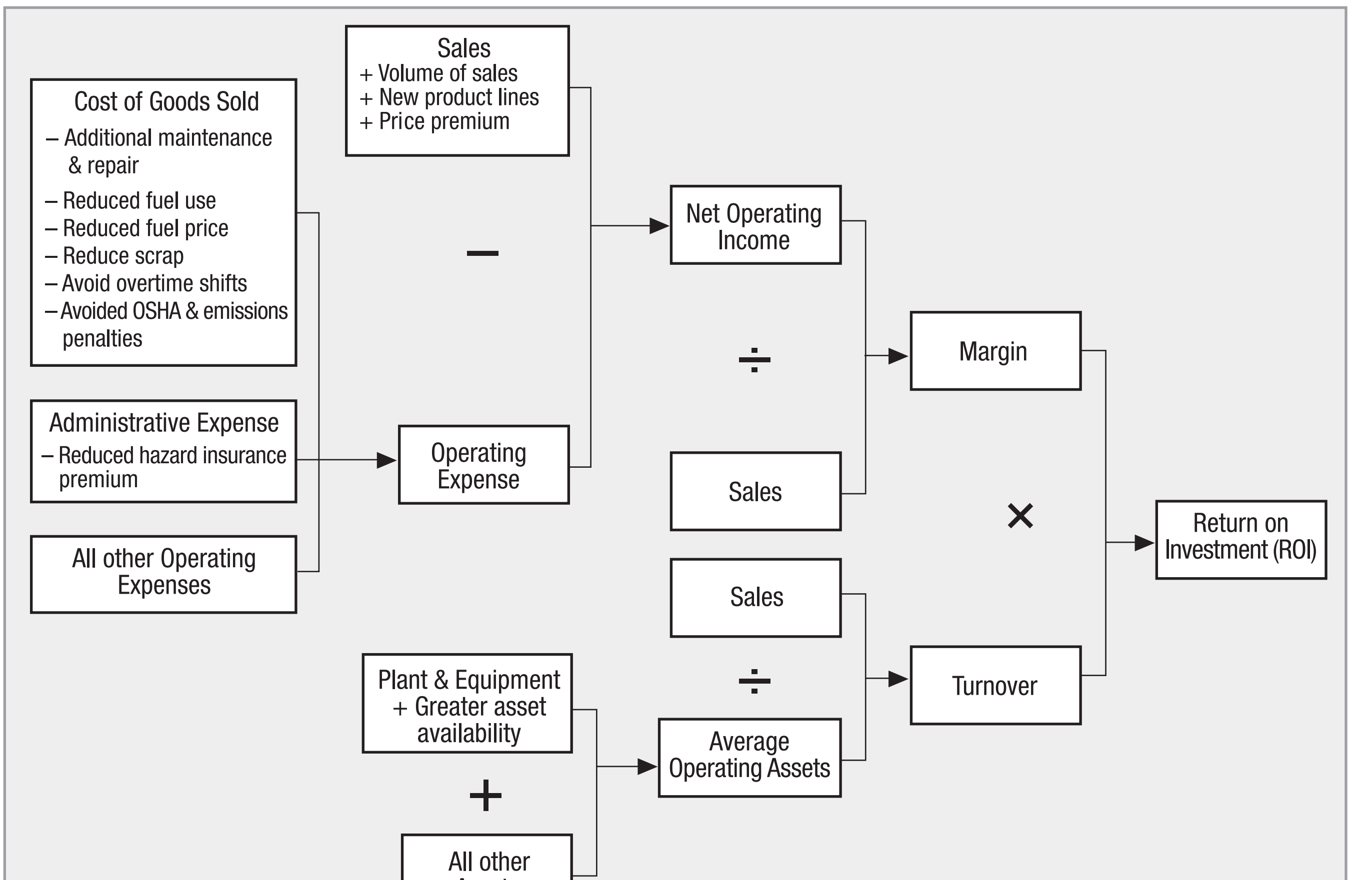
This section illustrates a hypothetical manufacturer's step-wise improvement of return on investment. Each of the consolidated financial statements in this sequence (Appendices 1 through 3) shows the financial elements that make up ROI.

**Step 1.** Appendix 1 is a financial snapshot of manufacturing operations before implementation of a steam efficiency initiative. There is nothing remarkable about this model statement. The highlights include a profit margin of 10% (line 22), which means the company earns $0.10 from every $1 of revenue. The revenue generated by these assets is twice the value of the assets themselves (line 18). Together, margin and asset turnover (line 23) yield a return on investment of 20 % (line 24).

**Step 2.** Appendix 2 shows this company's consolidated financial statement for the accounting period after implementing steam efficiency. The steam plant superintendent spends more on operations and maintenance, labor, and training. In return, the savings in fuel expenditures, waste reduction, and reduced overtime more than compensate for the increases. Manufacturing now produces more gross margin (line 9). Savings for reduced emissions penalties and hazard insurance (lines 10 and 11) add to income performance (line 15).

The profitability of the plant is reflected in the increased margin (line 22), but this is facilitated in part by investment in new plant assets (line 16). Accordingly, asset turnover (line 23) declines relative to Step 1. Still, the magnitude of margin improvement more than compensates, so ROI is improved to 26.5% (line 24).

**Step 3.** In Appendix 3, the plant decides to capture the full economic value of its improvements. See that Step 2 generated an additional $456,000 in net income (line 15, Appendix 2). Since the plant makes money (it costs $0.854 to make $1 of revenue, line 21 of Appendix 2), it makes sense to reinvest these savings into production. Accordingly, production is increased by 533 units ($456,000 additional earnings divided by $854 production cost per unit). All manufacturing expenses (line 8) increase relative to Step 2, but this is mostly because of the increase in production. Higher salaries for better-trained plant staff (line 3) push overall expenditures even higher.



Adapted from: Garrison, 1991, p. 461. (4)

*Figure 2. Expanded elements of manufacturing return on investment.*

*Table 1. Summary of Steam Efficiency's Contribution to Manufacturing Return on Investment*

| Financial Metric | After Implementing Energy Efficiency | After Reinvesting Expense Savings into New Production |
|---|---|---|
| Revenues: | No change | Increase with production volume |
| Operating expenses: | Net decrease per unit | Increase with production volume |
| Net operating income: | Increases per unit & overall | Proportional increase greater than for expenses |
| Margin (%): | Increases as % of revenue | No additional increase as a percentage |
| Assets: | May increase* | No additional increase in magnitude |
| Asset turnover: | May decrease* | Increases with production volume |
| **Return on investment:** | **Increases with margin** | **Increases again with asset turnover** |

*Assets increase only if capital investments are required. Some initiatives require only operational changes. When capital investment is avoided, assets do not increase and asset turnover does not decrease. One study shows that about half of steam efficiency opportunities require only operational or behavioral changes (3).

But with margin per unit still at 15% (line 22), the increased production boosts the overall magnitude of net operating income even more (line 15). Finally, the increased production in Step 3 is generated without increasing the asset base, so asset turnover (line 23) improves relative to Step 2. Despite the constant margin, the improvement in asset turnover is enough in Step 3 to increase ROI by another 2.3 percentage points, to 28.8 % (line 24).

Note that this analysis omits some additional opportunities. For example, the steam efficiency initiative as described here simply increased capacity for making more of the same product. An alternative would be to let that capacity serve a new product line—perhaps one that is marketed as a "green" or environmentally friendly alternative. As such, the new product may command a premium price, which ultimately would have driven return on investment even higher.

Who benefits from steam efficiency? Figure 2 shares again the ROI schematic, but with detail showing impacts on specific financial elements.

Table 1 summarizes the financial contribution of steam efficiency to a manufacturer's ROI.

In the final analysis, the investment in steam system optimization provides benefits beyond the boiler room. True, plant staff gets some training and a corresponding boost in pay. The steam plant superintendent gets the resources to upgrade steam assets and maintenance. But in addition, product managers enjoy lower costs per unit due to reduced waste of direct materials, as well as avoided downtime. Sales and marketing staff enjoy a bit more negotiating room since the spread between product cost and price has widened. The corporate officers demonstrate to shareholders a higher return on investment, thus positioning the company well for attracting more investment capital. Finally, the manufacturing operation survives another round in the continuing battle with global competition.

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3. Robert Griffin, *The Enbridge "Steam Saver" Program, Steam Boiler Plant Efficiency Update to Year-End 2002*, March 2003.
4. Ray H. Garrison, *Managerial Accounting*, Sixth Edition, Irwin Publications, 1991.

*STEP 1: Financial position prior to any energy efficiency implementation*

| | | Units | Price Per Unit | Financial Result | Comments |
|---|---|---|---|---|---|
| Line 1 | **REVENUE** | 10,000 | $1,000 | **$10,000,000** | |
| | **COST OF GOODS MANUFACTURED** | | *Cost Per Unit* | | |
| Line 2 | Direct materials: | for 10,000 units | $300/unit | $3,000,000 | Any waste is reflected in the cost per unit. |
| Line 3 | Direct labor (fully loaded): | 12,000 hours | $66.67/hour | 800,000 | Average fully-loaded salary for staff of six, each working 2,000 hrs./year. |
| Line 4 | Overtime (fully loaded): | 1,000 hours | $100/hour | 100,000 | Driven by extra shifts needed to compensate for downtime. |
| Line 5 | Operations & maintenance: | | | 700,000 | Includes consumables, service contracts, etc. |
| Line 6 | Boiler fuel purchases: | 400,000 MMBtu | $5.00/MMBtu | 2,000,000 | Price is average across fixed-contract and spot-market purchases. |
| Line 7 | Other manufacturing expense: | | | 400,000 | Overhead and any other manufacturing expenses. |
| Line 8 | Total Cost of Goods Manufactured: | | | $7,000,000 | |
| Line 9 | **GROSS MARGIN** | | | **$3,000,000** | Gross margin is value generated by manufacturing, prior to administrative costs. |
| | **ADMINISTRATIVE EXPENSES** | | | | |
| Line 10 | OSHA & emissions penalties: | | | 200,000 | Some companies actually budget for these! |
| Line 11 | Hazard insurance: | | | 1,000,000 | |
| Line 12 | All other expenses: | | | 800,000 | Includes front office salaries, legal, audit expenses, etc. |
| Line 13 | Total Administrative Expenses: | | | $2,000,000 | |
| Line 14 | **TOTAL OPERATING EXPENSES** | | | **$9,000,000** | |
| Line 15 | **NET OPERATING INCOME** | | | **$1,000,000** | |
| | **ASSETS** | | | | |
| Line 16 | Plant & equipment: | | | $4,000,000 | |
| Line 17 | All other assets | | | 1,000,000 | |
| Line 18 | Average operating assets | | | $5,000,000 | |
| | **FINANCIAL METRICS** | | | | |
| Line 19 | Fuel cost per unit of production | (Total fuel cost ˜ Units prod uced) | | $200 | |
| Line 20 | All other costs per unit | (All other costs ˜ Units produced) | | $700 | |
| Line 21 | Total expense per unit: | (Total expenses ˜ Units produced) | | $900 | The plant is like a "money machine": put $0.90 in one end to get $1 out of the other. |
| Line 22 | Margin: | (Net operating income ˜ Revenue) | | 10% | This plant makes $0.10 cents on the dollar. |
| Line 23 | Asset turnover: | (Revenue ˜ Avg. operating assets) | | 2.0 | Assets pay for themselves twice a year in the form of revenue produced. |
| Line 24 | **RETURN ON INVESTMENT** | (Margin x Asset turnover) | | **20.0%** | A modest return-- more than treasury bills, but it can be better. |

*STEP 2: Financial position after implementing steam efficiency initiative*

| | | Units | Price Per Unit | Financial Result | Variance* from Step 1 | Explanation of Variance from Step 1 |
|---|---|---|---|---|---|---|
| .ine 1 | **REVENUE** | 10,000 | $1,000 | **$10,000,000** | $0 | No change. |
| | **COST OF GOODS MANUFACTURED** | | Cost Per Unit | | | |
| .ine 2 | Direct materials: | for 10,000 units | $285/unit | $2,850,000 | $150,000 | Optimization of thermal resources reduces waste. |
| .ine 3 | Direct labor (fully loaded): | 13,500 hours | $66.67/hour | 900,000 | -$100,000 | Optimization requires greater labor input. |
| .ine 4 | Overtime (fully loaded): | 500 hours | $100/hour | 50,000 | $50,000 | Optimized performance = reduced downtime = less overtime needed. |
| .ine 5 | Operations & maintenance: | | | 900,000 | -$200,000 | Improved monitoring & maintenance increases O&M costs. |
| .ine 6 | Boiler fuel purchases: | 360,000 MMBtu | $4.90/MMBtu | 1,764,000 | $236,000 | Optimization reduces fuel consumption; allows greater use of low-price fixed contracts. |
| .ine 7 | Other manufacturing expense: | | | 405,000 | -$5,000 | Training expenses increase as staff skills are developed. |
| .ine 8 | Total Cost of Goods Manufactured: | | | $6,869,000 | $131,000 | Fuel savings and waste minimization outweigh other cost increases. |
| .ine 9 | **GROSS MARGIN** | | | **$3,131,000** | $131,000 | Gross margin isolates cost/price effectiveness of manufacturing from front office costs. |
| | **ADMINISTRATIVE EXPENSES** | | | | | |
| .ine 10 | OSHA & emissions penalties: | | | 25,000 | $175,000 | Optimization enhances safety; emissions drop proportionately with fuel consumption. |
| .ine 11 | Hazard insurance: | | | 850,000 | $150,000 | Clean log book is leverage for lower insurance premiums. |
| .ine 12 | All other expenses: | | | 800,000 | $0 | No change. |
| .ine 13 | Total Administrative Expenses: | | | $1,675,000 | $325,000 | Summary of plant optimization cost benefits that accrue to the front office. |
| .ine 14 | **TOTAL OPERATING EXPENSES** | | | **$8,544,000** | $456,000 | A net improvement in total expenses. |
| .ine 15 | **NET OPERATING INCOME** | | | **$1,456,000** | $456,000 | A dollar saved is a dollar earned-- it adds to income. |
| | **ASSETS** | | | | | |
| .ine 16 | Plant & equipment: | | | $4,500,000 | -$500,000 | Optimization requires some investment in new (or replacement) equipment. |
| .ine 17 | All other assets | | | 1,000,000 | $0 | |
| .ine 18 | Average operating assets | | | $5,500,000 | -$500,000 | |
| | **FINANCIAL METRICS** | | | | | |
| .ine 19 | Fuel cost per unit of production | (Total fuel cost ˜ Units prod uced) | | $176 | $24 | |
| .ine 20 | All other costs per unit | (All other costs ˜ Units produced) | | $678 | $22 | |
| .ine 21 | Total expense per unit: | (Total expenses ˜ Units produced) | | $854 | $46 | Now, the "money machine" only requires $0.854 in one end to get $1 out the other. |
| .ine 22 | Margin: | (Net operating income ˜ Revenue) | | 15% | 5% | Margin reflects cost/price business efficiency. |
| .ine 23 | Asset turnover: | (Revenue ˜ Avg. operating assets) | | 1.8 | -0.2 | The addition of new assets adversely impacts asset turnover. |
| .ine 24 | **RETURN ON INVESTMENT** | (Margin x Asset turnover) | | **26.5%** | 6.5% | The improved margin more than compensates for decreased asset turnover. |

* Variances that increase ROI are shown as positive numbers; detractions from ROI are negative.

*STEP 3: Financial position after reinvesting savings in production*

| | | Units | Price Per Unit | Financial Result | Variance* from Step 2 | Explanation of Variance from Step 2 |
|---|---|---|---|---|---|---|
| Line 1 | **REVENUE** | 10,533 | $1,000 | **$10,533,000** | $533,000 | Expense savings from Step 2 are reinvested to produce more goods-- and revenue. |
| | | | Cost Per Unit | | | |
| | **COST OF GOODS MANUFACTURED** | | | | | |
| Line 2 | Direct materials: | for 10,533 units | $285/unit | $3,001,905 | -$151,905 | Cost per unit is unchanged from Step 2, but number of units increases. |
| Line 3 | Direct labor (fully loaded): | 14,200 hours | $70/hour | 994,000 | -$94,000 | Increased production requires more labor hours, plus wages reflect value of training. |
| Line 4 | Overtime (fully loaded): | 500 hours | $100/hour | 50,000 | $0 | No change from Step 2. |
| Line 5 | Operations & maintenance: | | | 945,000 | -$45,000 | O&M increases proportionately with output. |
| Line 6 | Boiler fuel purchases: | 379,188 MMBtu | $4.90/MMBtu | 1,858,021 | -$94,021 | Fuel expense increases proportionately with production. |
| Line 7 | Other manufacturing expense: | | | 426,587 | -$21,587 | Other expenses increase more or less proportionately with production. |
| Line 8 | Total Cost of Goods Manufactured: | | | $7,275,513 | -$406,513 | Higher output explains greater total expenditure relative to Step 2. |
| Line 9 | **GROSS MARGIN** | | | **$3,257,487** | $126,487 | Higher production more than compensates for greater expenditures relative to Step 2. |
| | **ADMINISTRATIVE EXPENSES** | | | | | |
| Line 10 | OSHA & emissions penalties: | | | 25,000 | $0 | No change from Step 2. |
| Line 11 | Hazard insurance: | | | 850,000 | $0 | No change from Step 2. |
| Line 12 | All other expenses: | | | 800,000 | $0 | No change from Step 2. |
| Line 13 | Total Administrative Expenses: | | | $1,675,000 | $0 | No change from Step 2. |
| Line 14 | **TOTAL OPERATING EXPENSES** | | | **$8,950,513** | -$406,513 | Higher than Step 2, but still lower than Step 1, despite additional level of production. |
| Line 15 | **NET OPERATING INCOME** | | | **$1,582,487** | $126,487 | Increase in revenue more than compensates for rise in expenses. |
| | **ASSETS** | | | | | |
| Line 16 | Plant & equipment: | | | $4,500,000 | $0 | No change from Step 2. |
| Line 17 | All other assets | | | 1,000,000 | $0 | No change from Step 2. |
| Line 18 | Average operating assets | | | $5,500,000 | $0 | No change from Step 2. |
| | **FINANCIAL METRICS** | | | | | |
| Line 19 | Fuel cost per unit of production | (Total fuel cost ˜ Units produced) | | $176 | $0 | |
| Line 20 | All other costs per unit | (All other costs ˜ Units produced) | | $673 | $5 | |
| Line 21 | Total expense per unit: | (Total expenses ˜ Units produced) | | $850 | $5 | Since administrative costs did not increase with output, scale economies are realized. |
| Line 22 | Margin: | (Net operating income ˜ Revenue) | | 15% | 0% | Cost/price efficiency ratio remains the same from Step 2. |
| Line 23 | Asset turnover: | (Revenue ˜ Avg. operating assets) | | 1.9 | 0.1 | Increased output increases asset turnover relative to Step 2. |
| Line 24 | **RETURN ON INVESTMENT** | (Margin x Asset turnover) | | **28.8%** | 2.3% | Improvement in asset turnover alone, relative to Step 2, drives ROI higher. |

* Variances that increase ROI are shown as positive numbers; detractions from ROI are negative.

# The Steam System Assessment Tool (SSAT): Estimating Steam System Energy, Cost, and Emission Savings

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The U. S. Department of Energy's (DOE) BestPractices Steam program is developing software tools to assist industrial energy users to improve the efficiency of their steam systems. Many steam systems offer energy savings opportunities that can amount to 10% to 20% of fuel costs.

In December 2002, BestPractices Steam released a major new software tool—the Steam System Assessment Tool (SSAT). SSAT is designed to allow steam analysts to develop approximate models of real steam systems. Using these models, SSAT can be applied to quantify the magnitude—energy, cost, and emission savings—of key potential steam improvement opportunities. SSAT is a reliable screening tool that contains the key features of typical steam systems. The tool is designed for use by engineers who operate or improve the operations of steam systems.

SSAT was developed for DOE, under contract with the Oak Ridge National Laboratory, by Linnhoff March and Spirax Sarco, Inc.

This paper discusses the most important characteristics of SSAT, and describes the process used to develop the initial version of the tool that was released in December 2002. Major benefits that can result from using SSAT are then presented. Finally, future activities related to training on the use of SSAT and future modifications to the software are discussed.

## Evaluating the "What-If" Steam System Improvement Scenarios

An accurate way to analyze potential steam system savings is to build a model of a steam system and to then use that model to evaluate "what-if" steam system improvement scenarios. SSAT is designed to model steam systems in this way. SSAT uses a graphical model of a generic steam system for up to three steam pressure headers: high, medium, and low. These types of major steam system equipment can be simulated using SSAT:

- Boilers
- Backpressure turbines
- Condensing turbines
- Deaerators
- Steam traps, leaks, insulation losses
- Letdowns
- Flash vessels
- Feedwater heat exchangers.

SSAT users can enter data for their plant conditions. This includes fuel type and cost, electricity and water costs, initial boiler efficiency, header pressures, turbine efficiencies, etc. Then, they can then evaluate "what-if" scenarios for the following types of key improvement opportunities:

- Using an alternative boiler fuel
- Improving boiler efficiency
- Reducing boiler blowdown rate
- Changing steam generation conditions
- Installing a blowdown flash system to produce low-pressure steam
- Installing new backpressure turbine(s)
- Installing a new condensing turbine
- Installing new heat recovery exchangers to preheat feedwater
- Increasing condensate recovery
- Reducing steam trap losses and losses from steam leaks
- Reducing pipe work insulation heat losses.

SSAT software runs as an add-in within Microsoft® Excel spreadsheet software.

Three initial software templates are provided with the software for “1-header,” “2-header,” and “3-header” pressure template models. These models are Excel files (*.xls) that require the SSAT software to be loaded to function properly.

Each of the SSAT model templates includes six worksheets: Input, Model, Projects Input, Projects Model, Results, and User Calculations. The major functions of these six worksheets are described below.

- The **Input** worksheet allows the SSAT user to enter data specific to the operation of a given steam system. Upon installation, the SSAT template files provided already contain default data, but this data can be overwritten for the steam system being modeled. Appendix 1 illustrates a portion of the Input sheet for the 3-header template model.
- The **Model** worksheet shows a schematic of the steam system being modeled that is based on the data entered in the Input worksheet. Appendix 2 shows the Model schematic for the 3-header template model.
- The **Projects Input** worksheet allows the SSAT user to select one or more pre-defined steam improvement projects to evaluate. Appendix 3 illustrates a portion of the Projects Input worksheet for the 3-header template. The SSAT user, for example, could evaluate the potential for implementing “Project 2—Change Boiler Efficiency” by changing the existing boiler efficiency to a new value and determining how this changes energy, cost, and emissions values for the steam system being modeled.
- The **Projects Model** worksheet is similar to the Model worksheet discussed above except that the schematic now shows the updated steam system conditions for the projects specified in the Projects Input worksheet.
- The **Results** worksheet shows the key energy, cost, and emissions results for the initial system conditions, specified in the Input worksheet, and the system conditions resulting from implementing steam system opportunities, specified in the Projects Input worksheet. As shown in Appendix 4, the results are presented in tabular form, allowing the SSAT user to quickly assess the impact of any proposed changes to their steam system.
- Finally, SSAT includes a **User Calculations** worksheet, with which the software user can perform any supplemental calculations that might be needed for using SSAT.

## Developing the Initial Version

The SSAT Software Development Team consisted of the authors of this paper. The effort to develop the SSAT software was initiated in March 2002. At that time, a meeting was held to discuss the following topics:

- Overall purpose for the software
- Software inputs and outputs
- Details of the software structure
- Software usability to ensuring that SSAT would be made as simple to use as possible
- How software verification calculations would be performed
- How technical review of the beta version of the software will be conducted
- Development of an outline for the software users guide.

Based on the March 2002 meeting to set the initial SSAT software requirements, the first beta version was completed in early July 2002. At that time, a number of steam system experts were asked to perform a technical review of the software. The experts and organizations that performed the SSAT software technical review are listed in the Acknowledgements section of this paper. The technical reviewers were given 2 months to provide their technical review comments on the software.

To verify the accuracy of the SSAT modeling approach, Dr. Greg Harrell performed SSAT calculations for sample problems that are contained in the *Steam System Survey Guide* (1). Agreement between the guide’s results and the SSAT results was excellent.

The SSAT Software Development Team responded to the comments from the technical reviewers. At the same time that final software modifications were being made, the SSAT Users Guide (which is available as a PDF file and as a “Help” file within the software) was completed.

The SSAT software was initially released through the DOE BestPractices Web site at *www.eere.energy.gov/industry/bestpractices* in December 2002. A stand-alone CD version of the software was released in January 2003. The SSAT is also included on the Decision Tools for Industry CD, which contains all of the DOE BestPractices software tools.

## SSAT Benefits

In designing SSAT, efforts by the Software Development Team focused on ensuring that it would be a useful tool for identifying opportunities to improve steam systems. The key benefits of using the SSAT are described below:

- The SSAT can be used to model the major improvement opportunities that are typically possible in steam systems. In addition, SSAT can model more than one opportunity at a time, so that the user can see how multiple opportunities affect the results.
- The SSAT was designed based on the "80/20" principle. It was developed to be powerful enough to model major steam improvement opportunities, but was kept simple by not attempting to model all potential steam improvements.
- The SSAT data input interface is simple to use. For many real steam systems, it is expected that a system model can be set up in a few hours or less.
- The SSAT has models for estimating both on-site and off-site emissions. The user can see how reducing fuel use affects on-site emissions of $CO_2$, $SO_X$, and $NO_X$. Including both on-site and off-site emissions can be very important for modeling the environmental effects of generating on-site power using backpressure turbine generators.
- In addition to being a steam system analysis tool, the SSAT can also be used as a training tool. The Model and Projects Model graphical worksheets illustrate how various modeling changes influence the steam system being modeled SSAT is a true system-modeling tool.

## More to Come!

As of July 2003, there are more than 1,300 registered users of SSAT software.

The BestPractices Steam program presents 1-day steam End User training, where SSAT examples are presented. In addition, a BestPractices Steam Qualified Specialist training program has been developed to qualify users who want to become experts in the use of SSAT software and other BestPractices Steam tools.

It is expected that there will be future versions of SSAT released, based on feedback from users of the software. Updates will include corrections to any modeling errors discovered, and will perhaps include additional or enhanced modeling based on user feedback.

## Summary and Conclusions

SSAT is a major addition to the overall "toolbox" that the DOE BestPractices Steam program has developed for the steam user community. Use of SSAT is expected to greatly enhance the awareness of the many opportunities that are available for improving the efficiency and productivity of steam systems.

## References

1. Dr. Greg Harrell, *Steam Survey Guide,* ORNL/TM-2001/263, May 2002.

## Acknowledgements

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- American Boiler Manufacturer's Association
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- Oregon State University
- Riyaz Papar
- Plant Support and Evaluations, Inc.
- Sunoco
- University of Tennessee/Knoxville
- Washington State University

*Appendix 1. SSAT "Input " Worksheet, 3-Header Template (Full Sheet Not Shown)*

# Steam System Assessment Tool

## 3 Header Model

### Data Entry Form for Current System

The data entry form is split into two sections. *"Quick Start"* enables you to enter a minimum amount of information about your site and to start modeling your system right away. *"Site Detail"* allows you to provide more detailed information about your site to improve the accuracy of the model.

Yellow shaded cells require user input.

Where different options can be chosen by the user, the required supplementary data input cells are shaded green and are indicated by *red arrows*.

## *Quick Start*

| Enter Case Description | SSAT Default 3 Header Model |
|---|---|

| General Site Data | Input Data | Notes/Warnings |
|---|---|---|
| Site Power Import (+ for import, - for export) | 5000 kW | Power import + site generated power = site electrical demand |
| Site Power Cost | 0.0700 $/kWh | Typical 2002 value: $0.07/kWh |
| Operating hours per year | 8000 hrs | |
| Site Make-Up Water Cost | 0.0025 $/gallon | Typical 2002 value: $0.0025/gallon |
| Make-Up Water Temperature | 50 F | |

Note: Enter average values for the operating period being modeled

| | | |
|---|---|---|
| Boiler fuel - Choose from this drop-down list | | Natural Gas |
| Site Fuel Cost per 1000 s.cu.ft | 5.00 $ | Typical 2002 value: $5.00/(1,000 s cu.ft) |

Note: Fuel HHV is 1,000 Btu per s.cu.ft (21,032 Btu/lbm)

| Steam Distribution | Input Data | Warnings |
|---|---|---|
| High Pressure (HP) | 600 psig | |
| Medium Pressure (MP) | 150 psig | |
| Low Pressure (LP) | 20 psig | |
| HP Steam Use by Processes | 50 klb/h | |
| MP Steam Use by Processes | 100 klb/h | |
| LP Steam Use by Processes | 200 klb/h | |

Note: Enter process steam use at each pressure level. Excludes turbines, letdowns, leaks, trap losses, deaeration steam and vents

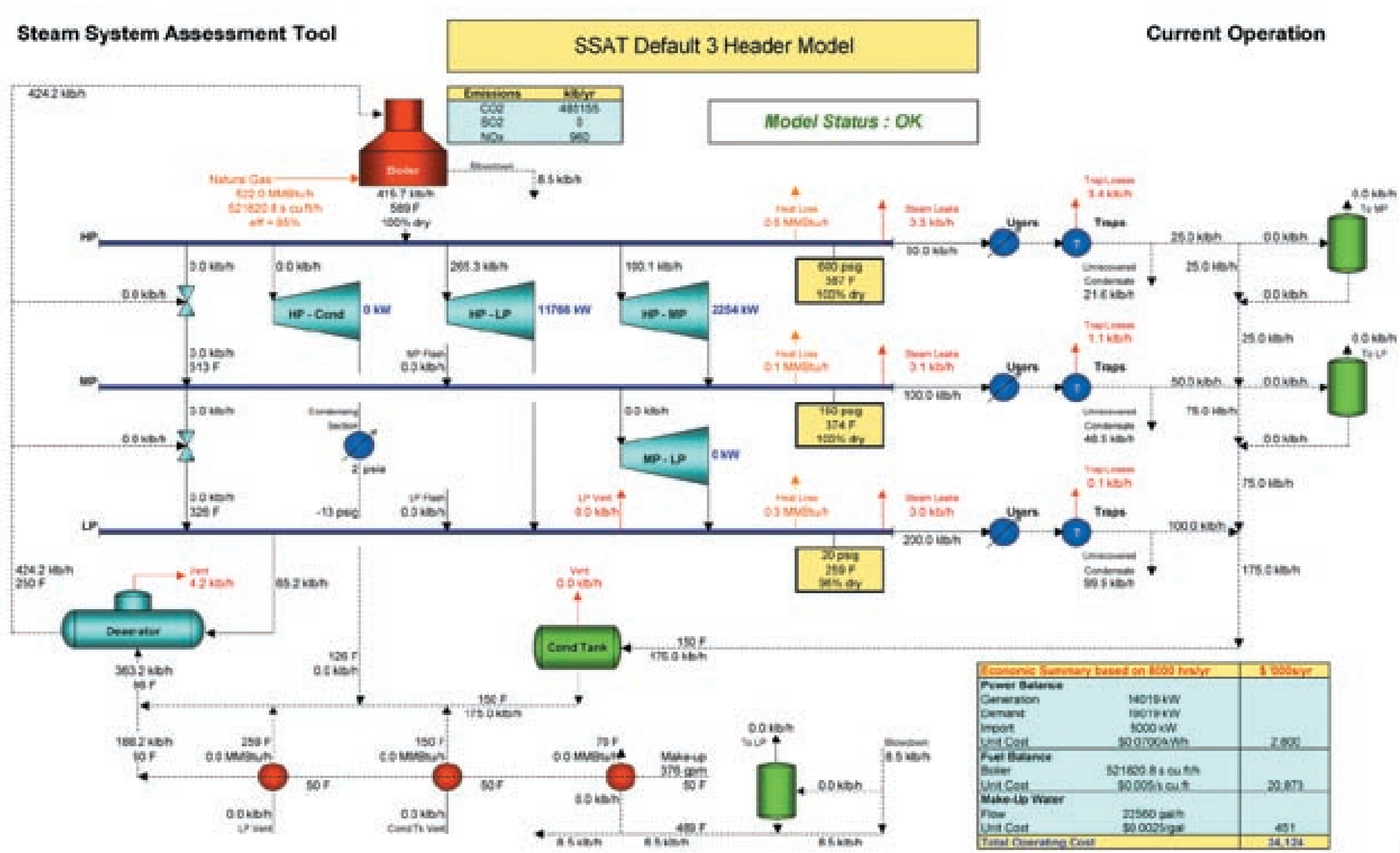
| Steam Turbines | |
|---|---|
| Do you have a steam turbine installed between HP and LP? | Yes |
| Do you have a steam turbine installed between HP and MP? | Yes |
| Do you have a steam turbine installed between MP and LP? | No |
| Do you have an HP to condensing turbine installed? | No |

For a **Condensing Turbine**, please define how the turbine operates and then provide supplementary information below:

| Mode of operation | Not installed |
|---|---|

| | | |
|---|---|---|
| Option 1 - Fixed power generation | 1000 kW | |
| Option 2 - Fixed steam flow | 50 klb/h | |

Appendix 2. SSAT Graphical Model Worksheet, 3-Header Template



*Appendix 3. SSAT "Projects Inputs Worksheet 3-Header Template (Full Worksheet Not Shown)*

# Steam System Assessment Tool

## 3 Header Model

### Projects Entry Form

Use this form to specify improvement projects. These projects will then be modeled and compared to the existing operation.

**Project 1 - Use an Alternative Fuel**
Existing Boiler Fuel : Natural Gas Fuel Cost : $0.005/s cu.ft

| | | |
|---|---|---|
| Do you wish to specify an alternative fuel? | | No |
| If yes, choose a new fuel from this drop-down list | | Number 2 Fuel Oil |
| Site Fuel Cost | 0.67 $/gallon | Typical 2002 value: $0.67/gallon |

Note: HHV for alternative fuel is 139,213 Btu per gal (18,275 Btu/lbm)

**Project 2 - Change Boiler Efficiency**
Existing Efficiency : 85%

| | | |
|---|---|---|
| Do you wish to specify a new boiler efficiency? | | No |

Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency

| | | |
|---|---|---|
| If yes, enter new boiler efficiency (%) | 90 % | |

Note: Typical Best Practice boiler efficiency for Natural Gas is 85%

**Project 3 - Change Boiler Blowdown Rate**
Existing Blowdown Rate : 2%

| | | |
|---|---|---|
| Do you wish to specify a new boiler blowdown rate? | | No |
| If yes, enter new rate (% of feedwater flow) | 1 % | |

**Project 4 - Blowdown Flash to LP**
Not currently installed

| | |
|---|---|
| Do you wish to modify the blowdown flash system? | Option 2 - No change |

**Project 5 - Change Steam Generation Conditions**
Existing Conditions : 600 psig. Superheated steam at 589 F

| | | |
|---|---|---|
| Do you wish to change the HP steam generation conditions? | | Option 3 - No change |
| Option 1 - Enter temperature | 600 F | |

Note: Saturation temperature at specified HP pressure (600 psig) is 489 F

| | | |
|---|---|---|
| Option 2 - Enter thermodynamic quality | 99.9 % dry | |

*Appendix 4. SSAT "Results " Worksheet, 3-Header Template (Full Worksheet Not Shown)*

**Steam System Assessment Tool**

3 Header Model

**Results Summary**

SSAT Default 3 Header Model

*Model Status : OK*

| Cost Summary ($ '000s/yr) | Current Operation | After Projects | Reduction | |
|---|---|---|---|---|
| Power Cost | 2,800 | 2,800 | 0 | 0.0% |
| Fuel Cost | 20,873 | 20,873 | 0 | 0.0% |
| Make-Up Water Cost | 451 | 451 | 0 | 0.0% |
| **Total Cost (in $ '000s/yr)** | **24,124** | **24,124** | **0** | **0.0%** |

| On-Site Emissions | Current Operation | After Projects | Reduction | |
|---|---|---|---|---|
| CO2 Emissions | 485155 klb/yr | 485155 klb/yr | 0 klb/yr | 0.0% |
| SOx Emissions | 0 klb/yr | 0 klb/yr | 0 klb/yr | 0.0% |
| NOx Emissions | 960 klb/yr | 960 klb/yr | 0 klb/yr | 0.0% |

| Power Station Emissions | Reduction After Projects | Total Reduction | |
|---|---|---|---|
| CO2 Emissions | 0 klb/yr | 0 klb/yr | - |
| SOx Emissions | 0 klb/yr | 0 klb/yr | - |
| NOx Emissions | 0 klb/yr | 0 klb/yr | - |

Note - Calculates the impact of the change in site power import on emissions from an external power station. Total reduction values are for site + power station

| Utility Balance | Current Operation | After Projects | Reduction | |
|---|---|---|---|---|
| Power Generation | 14019 kW | 14019 kW | - | - |
| Power Import | 5000 kW | 5000 kW | 0 kW | 0.0% |
| Total Site Electrical Demand | 19019 kW | 19019 kW | - | - |
| Boiler Duty | 522.0 MMBtu/h | 522.0 MMBtu/h | 0.0 MMBtu/h | 0.0% |
| Fuel Type | Natural Gas | Natural Gas | - | - |
| Fuel Consumption | 521820.8 s cu.ft/h | 521820.8 s cu.ft/h | - | - |
| Boiler Steam Flow | 415.7 klb/h | 415.7 klb/h | 0.0 klb/h | 0.0% |
| Fuel Cost (in $/MMBtu) | 5.00 | 5.00 | - | - |
| Power Cost (as $/MMBtu) | 20.51 | 20.51 | - | - |
| Make-Up Water Flow | 22560 gal/h | 22560 gal/h | 0 gal/h | 0.0% |

| Turbine Performance | Current Operation | After Projects | Marginal Steam Costs (based on current operation) | |
|---|---|---|---|---|
| HP to LP steam rate | 44 kWh/klb | 44 kWh/klb | HP ($/klb) | 7.03 |
| HP to MP steam rate | 23 kWh/klb | 23 kWh/klb | MP ($/klb) | 5.45 |
| MP to LP steam rate | Not in use | Not in use | LP ($/klb) | 3.92 |
| HP to Condensing steam rate | Not in use | Not in use | | |

| List of Selected Projects |
|---|
| |

| Gas Turbine Assessment |
|---|
| Your site is a very good candidate for the installation of a gas turbine + waste heat boiler |

Warnings - Any warnings listed below may impact on the validity of the simulation

| Current Operation | After Projects |
|---|---|
| | |

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