Understanding and reducing energy and costs in industrial cooling systems

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Abstract

Industrial cooling remains one of the largest potential areas for electrical energy savings in industrial plants today. This is in spite of a relatively small amount of attention paid to it by energy auditors and rebate program designers. US DOE tool suites, for example, have long focused on combustion related systems and motor systems with a focus on pumps and compressors. A chilled water tool designed by UMass was available for some time but is no longer being supported by its designers or included in the government tool website. Even with the focus on motor systems, auditing programs like the DOE's Industrial Assessment Center program show dramatically less energy savings for electrical based systems than fossil fueled ones. This paper demonstrates the large amount of increased saving from a critical review of plant chilled water systems with both hardware and operational improvements. After showing several reasons why cooling systems are often ignored during plant energy surveys (their complexity, lack of data on operations etc.), three specific upgrades are considered which have become more reliable and cost effective in the recent past. These include chiller changeouts, right sizing of systems with load matching, and floating head pressures as a retrofit. Considerations of free cooling and improved cooling tower operations are shown as additional 'big hitters". It is made clear that with appropriate measurements and an understanding of the cooling system, significant savings can be obtained with reasonable paybacks and low risk.

Introduction

An analysis of the energy savings identified during audits will quickly show that the "low hanging fruit" is most easily obtained with fossil fuel systems. Waste heat recovery, better operation, fuel switching etc. provide a long list of available measures which often save industrial plants over 20% of their annual energy consumption. Electricity is much harder. First, motors have become very efficient both do to advances in technology and enacted laws requiring minimum efficiencies. Lighting systems, a fertile ground for energy improvement, have seen large market penetration. In some areas the revenues of some consulting firms which relied almost entirely on lighting upgrades has begun to fall requiring changes in the business model.

Further analysis will show that in many plants the use of chillers and associated hardware is a major consumer of electrical energy. Yet in many cases these expensive and complex systems are operated with little control other than to make sure the chilled water loop is cooled to a desired temperature. Some plant managers confess to operating by "feel" which normally means there is energy and money to be saved. A government database for the Industrial Assessment Center Program with results from over 15,000 assessments shows a mere 1.1% of recommendations involved cooling and 0.6% directly involved chillers!!!

When considering why chilled water systems are operated without operational optimization several possibilities occur:

- The large complexity of pumps, piping and controls – including operation of both the chillers and cooling towers
- "Why touch something that seems to be working???"
- Large capital expenditures to install the chillers leading to an installed base which is quite old
- Competing control schemes associated with older machines
- Lack of appreciation for the amount of energy that can be saved
- General lack of necessary measurements such as flow rates and temperatures on cooling loops and other heat exchangers

The sophistication of chiller and cooling tower design is advanced. Software tools, AHRAE standards, and a great deal of experience make this part of the problem straightforward. ASHRAE Standard 90 (from 1975 with periodic updates) defines efficiency requirements for new construction and remodeling and includes guides for energy management professionals.

It is clear, though, that this sophistication does not extend to the operation of the chilled systems especially many years after the initial design and installation.

The job of cooling has also changed. The advent of large cooling loads for server farms both in data centers and more simple industrial facilities has changed the normal duty cycles for chillers and chilled water systems. Historically in large buildings, internal zones needed cooling throughout the winter resulting in chiller operation in some cases. But for the most part this cooling was available from other sources (outside) and it was common for some chillers to shut down in the winter months. This shutdown normally would include cooling towers which could be drained to avoid water freezing issues.

System Characterization

As a first step in analyzing the potential for savings in chilled water system general characterizations must be made. It is useful to split this up into three subareas

1. Chilled water generation

- Installed chillers

What is the installed base in terms of total chilling capacity and the individual sizes and ages of the available units? How are the machines dispatched? Is performance ever evaluated? What changes in operation are made seasonally?

- Cooling towers

Are there cooling towers supporting the chillers? How many and what size?[1] How are they controlled and what set points are used. As stated below, cooling towers seem even simpler than chillers in that what is normally controlled is the rotation rate of the fan which drives air flow evaporating the hot inlet water.,

2. Chilled water distribution

Chilled water is a means to an end. A process or space needs cooling. A good energy survey will examine the pumps and piping throughout the distribution system looking for proper insulation and proper flow rates. At some end points there are heat exchangers and some measurement of that performance of those devices will pay dividends rapidly.

3. Chilled water consumption

What are the primary uses of chilled water? What is the required temperature? Is the chilled water supply sufficient to handle cooling needs throughout

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[1] Sizing for cooling towers assumes a COP of the chiller system as 4.0. Therefore to remove 100 Btus using chillers requires 125 Btus to be removed from the cooling tower… Definitions of tons are different for cooling towers and chillers: a 100 ton chiller needs to be matched with a 100 ton cooling tower – the definition of ton is different for each. For chillers a ton of cooling = the removal of 12,000 Btu/hour (3500 W). The "*equivalent ton*" on the cooling tower side actually rejects about 15,000 Btu/hour (4400 W).

the year? Is there over cooling or wasted chilled water?

It seems silly to start with such simple questions but experience over more than three decades shows that much in the way of improvement comes from asking such simple questions. Several projects may come out of this – but it is important to proceed to the analysis of more expensive but potentially much more impactful projects such as those which follow.

Areas having the greatest potential

The aging chiller

Perhaps no machine is harder to get someone to upgrade than a chiller that is working. However with the significant losses in performance which can occur in older machines and new developments in technology, it is necessary to periodically evaluate whether and what should be acquired. Sometimes finding out the age and features of an older chiller can be quite challenging. However, the use of chillers which have lost nameplates, have been rebuilt and sold several times, and have little or no control or performance measuring instrumentation is all too common. This generates an atmosphere of running a chiller "by feel" which is anathema to an energy engineer. It also makes taking action to upgrade such a system nearly impossible.

Listing a few basic reasons a plant should consider upgrading.

1. Simple performance degradation

How are chillers expected to age? Certainly the thermodynamic laws are timeless, so either pressure, temperature or flow rate have to vary over time.

Since a chiller is really two big heat exchangers, it is expected that scaling and fouling of those surfaces will increase over time. This can be monitored by looking at the pressure drop across the condenser and evaporator bundles. An increase in pressure from the inlet to the outlet of 3-4 PSI indicates a probable increase in scale or fouling requiring tube cleaning. (Clark, 2001). Repaired leaks and other clogging problems will actually reduce the number of channels available for flow. This should show up in logs of maintenance[2], but will also contribute to larger pressure drops through the tube bundles.

An aging compressor will also have to work harder to produce the same flow rates and pressures. Wear and control of flow restrictors like inlet guide vanes (IGV) on centrifugal machines and slide valves on screws contribute to this the most.

Finally, flow through hot gas bypass control (HGBP) loops and economizer loops can be excessive, reducing the overall efficiency of the system.

All of these maladies are difficult to identify and quantify. The ability to measure real time COPs is key, yet is rarely done. Clearly without knowledge of how things are currently working, such a decision can only be guessed at. Temperatures are relatively easy to measure, as are kilowatt draws. But submetering is not sufficient. The difficulty is in flow rate measurements both for the circulating chilled water and the cooling tower loop. Available with orifice meters or other devices which require physical intrusion into the system, the absence of real data leaves most to use either rules of thumb[3], whole systems measurements (cooling load on an entire building based on cooling degree days) or use of modeling. A recent report (Thornton, Miller, Robinson, & Gillespie , 2008) includes only one case study where actual flow rates were measured (*site 1*). Things are made more complicated when several machines are present especially if there is a mix of vapor compression machines and absorbers.

This would not be critical if the costs associated with chiller upgrades were less. Clearly, in order to

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[2] Certainly an aggressive maintenance program should be in place with logging of both performance and any repairs. Several good sources are available which provide protocols for good maintenance (Sullivan, Pugh, Melendez, & Hunt, 2010).

[3] These rules are typically based on design values and typical temperature differences. Normally 2 GPM/ton is the evaporator flow and 3 GPM/ton is the condenser flow.

justify going forward with large projects, estimates must be replaced by hard numbers. There are solutions to the problem. The recommended approach would be to instrument the chilled water and condenser loops with "hot-tapped" or "wet-tapped" flow meters. ASHRAE (Guideline 22-2008) recommends vortex flow meters ($2100) but experience shows cup anemometers ($1200) and tappable Pitot tubes ($350) are less expensive and provide similar accuracies. The biggest difficulty is finding a point in the system where there is sufficient straight pipe to assure fully developed flow.

Normally even this will not be done with high measurement costs and some operational concerns with hot-tapping (leakage), and it is very useful to find another way to estimate flow rates. One method proposed here is to use the input to the cooling tower. If there are at least two cells having separate sumps, it is easy to close off one of the sump drains (with flow going back to the condenser) without impacting production. A sequence of steps is as follows:

- Estimate water makeup rates. Identify the means for water makeup in the tower – usually a float controlled valve. Using a bucket, measure the flow rate out of that source for a reasonable rate of time. Conversely, and if this is difficult, close off the makeup valve and record how long it takes for the water level in the sump to drop.
- Identify the overflow port – normally an open drain which is several inches above the steady state water height in the sump. Carefully measure this height difference.
- Close the drain from the sump completely. Makeup water should cease and the level raise until the overflow level is reached
- Geometry of the sump and the addition of makeup rates will yield a flow rate into that cell. This should be repeated for each cell.

Knowing the flow rate through the condenser loop and the ΔT across it will yield the total energy removed from the system. That total energy includes heat removed via the cooling water loop plus the electrical energy dissipated. An estimate for the instantaneous COP of the system is:

$$COP = \frac{(\dot{m}\Delta T)}{kWh} - 1$$

When results are measured, benchmarks can be used to put the current chiller performance into perspective. Should performance appear suspect, costs to install flow measuring equipment can be more easily justified.

2. Changes in plant products or operations

A stronger case and an easier sell can be made if the chiller is poorly matched to the job at hand. Sometimes the system was purchased with expansion in mind – other times the internal loading associated with a produced product has changed or the number of people involved in manufacture has changed such that the system is oversized.

Key to this and other operations is the recognition that chillers are operated off-load a

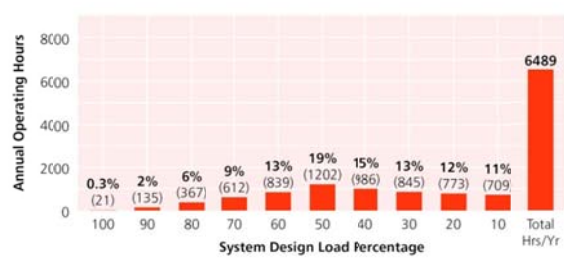

Figure 2. Load profile for typical space conditioning chillers ("Off-Load" Chiller Performance, 1996)

majority of the time. As shown in Figure 2, since the systems are sized for the worst case scenario (e.g. the hottest day of the year) they are grossly overdesigned for the majority of the hours they operate. The

industry uses special weighted averages ("integrated part load efficiencies" or IPLV) which currently use 50% load or less more than half the time.

Having several units that can be mixed and matched to exactly meet demand is a basic "no brainer". Screw compressors, for example, will operate well until about 60% load and then drop 20% in performance by a reduction to 30% load. Data from a study at LBNL is shown in Figure 3 for a 228 ton chiller. By adding a 100 ton chiller as an upgrade, dramatically improved performance will occur during the 50 percent of the year when the chillers are mostly unloaded.

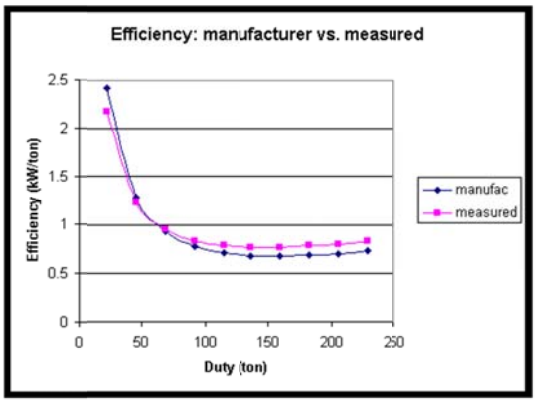

Figure 3: Off Load Degradation of Performance (Piette, et al., 1999)

How to implement this in practice is the challenge. Plants having a single chiller will need both space and added controlled systems to take full advantage of adding additional hardware. And if care is not taken to take the large machine offline when not needed, one could end up with a situation where performance is indeed worse.

Estimating upgrading potential

As a basis for further analysis, set points are needed in terms of cost and performance. It is simplified by the fact that chillers are ubiquitous in buildings and factories and are purchased to a catalog as opposed to being built to order. Same goes for cooling towers.

Typical cost metrics include: chiller cost per ton which depends on size but can be estimated at about $450 per ton (EPA, 2008). This is for an entire system. For the chiller itself, Trane estimates about $250/ton (Trane , 2000) and one could expect to sell a current chiller at about $25/ton.

Figure 4 shows the ASHRAE benchmark for centrifugal chillers. As one evaluates all of the improvements available, an improvement of 0.4 KW/ton of cooling is a reasonable target.

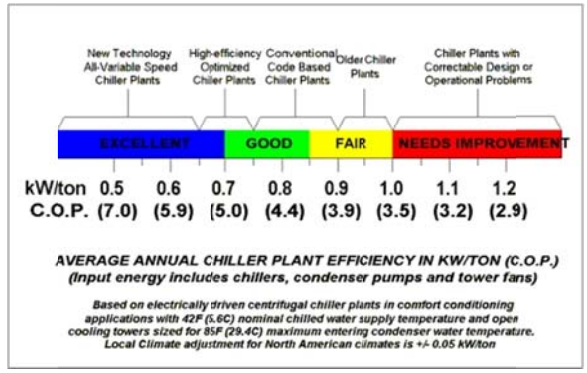

Figure 4: Centrifugal Chiller Benchmarks (Hartman, 2001)

The IAC database shows that upgrading an existing chiller with a new, higher efficiency model has an average payback of 5.2 years for industrial plants. This is far too long for most firms ROI hurdles and so the implementation rate is quite low. It is suspected that many of the implemented upgrades were motivated by equipment failures and large maintenance costs.

A careful look also shows a number of cost reducing techniques which indicate that a more real payback is much less. In determining the upgrade cost, these points need to be considered:

- Rebates are available to buy down costs in many localities
- Old chillers which are operating can normally be sold for about 10% of a new chiller
- Rules of thumbs for chiller installation are too high for chiller upgrades as much of the site prep and ancillary pumping and piping are already in place.
- Downsizing will reduce capital costs
- Current operational performance is normally overestimated

Cost to replace is about $225/ton so the number of hours to recover the replacement cost (at $.15/kwh) is:

Hrs = CAPEX/KWsavings*Kwhcost = 3750 hrs

With typical operating hours of 6500 per year, a chiller upgrade could pay off in as little as 7 months. Clearly other cases could be more expensive, but often an upgrade is not even considered due to the belief that paybacks are 5+ years and this is normally not the case.

Floating heads – the retrofit

While having been talked about for decades, the majority of chilled water systems still use constant head pressures on both suction and high pressure sides. Floating these pressures (FHP or FSP) can reduce compressor costs and improve system performance.

There are also several ways to achieve floating head improvements in existing chiller plants. These include:

1) Simple floating of the evaporator pressure/temperature.

In this case the thermostatic expansion valve (TXV) in the chiller is overridden to allow extra refrigerant flow when ambient temperatures are cool. This results in reduction in temperature (and pressure) in both the condenser and evaporator. Improved performance comes from a cooler evaporator which allows the chiller to cycle off more.

A detailed case study at a supermarket in Washington (Innovative Energy Products LLC, 2010) showed a significant energy savings of 34% and paybacks of about 1.5 years with an electricity price of $0.076/kWh. In many parts of the country the electricity prices will be significantly higher and the payback will be accordingly lower.

2) Condenser pressure reduction due to overdesign

In some cases the pressure set points on condenser are high compared to what is necessary for the thermostatic expansion valve to operate as designed. In one published case study (Brownell, 1998) a reduction in pressure from 220 psia to 155 psia met valve requirements and improved efficiency by 23%. Control was achieved by simply resetting the condenser pressure setpoint.

3) Compressor pressure reduction with liquid amplifier.

When insufficient pressure reduction is available because of TXV requirements, a liquid pressure amplifier can be added to the system after the condenser but before the valve, thereby allowing the compressor savings but not compromising the valve performance. Paybacks for this upgrade are estimated at 12-18 months (Joncas, 1993)

In some cases rebates are available which can buy down the payback even more. Maine, for example, offers about $250 per coil (*Efficiency Maine, Prescriptive Cash Incentives*)

Evaluating cooling tower performance

Cooling towers pay for themselves. They would not be as prevalent as they are if this was not the case. As a general rule of thumb, chiller energy is reduced by approximately 2% for every 1ºF of reduced condenser water temperature – and this is achieved by effective use of a cooling tower.

Often considerable thought and engineering design goes into decisions made when specifying and installing a cooling tower. Design choices are made on average data values for a location and average load characteristics for the building or plant. After installation, the actual operation of the cooling tower, while important for energy savings, is often left to "feel" or ignored.

It is well known that the performance of cooling towers is weather dependent. All too often the operation is accepted as-is. When used for lower a condenser temperature, for example, an operator will accept whatever temperature a cooling loop has returning from the cooling tower.

There is one primary control aspect for cooling towers, namely the amount of forced air which is flowing through it. This can be easily controlled with VSDs. However, to make the decision about how much air to put through a set of towers requires

analysis of not only the tower, but the chillers and the air flow system. As a rule, the fan energy increases with the cube of the imparted air velocity. At some point additional airflow will cost more in fan power than it will save energy in the chillers. Where this point is needs to be known as a function of weather conditions but rarely is. As a simple practice, however, it is important to run all available cooling towers even in off load situations. Often when loads are reduced, operators turn off some of the towers which is not best practice unless there are ancillary concerns such as freezing temperatures and non-operating towers are drained.

Maintenance and operational issues can also be greatly affected by how a tower is operated. If access doors are left open (a common occurrence), there will be less airflow across the fill and this can be seen in an increase in sump temperature for the same fan power. Excessive airflow can increase carryover to the point where water loss exceeds evaporative losses by a significant amount – again, if this is not being tracked, operators will only be able to guess at problems.

Discussion

Dramatic savings are available for cooling plants in industrial systems. They are often overlooked. In just about every case the installation of flow and temperature measuring instrumentation would lead to better operation and intelligent decision making with respect to upgrades. Estimation techniques are important first steps to demonstrate the types of insights a more accurate measurement scheme could provide.

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OBSTACLES AND OPPORTUNITIES: TURBINE MOTORIZATION IN REFINERIES TODAY

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ABSTRACT

Steam turbines have been widely used in oil refineries for driving pumps, compressors and other rotary machines. However, in recent years, the authors of this paper have seen substantial turbine motorization projects completed or being planned in the refineries. This paper discusses the key aspects that should be considered in evaluating the feasibility of motorization projects. Based on the literature review and a refinery survey conducted by the authors, the key factors include the critical level of the related equipment, the potential energy savings and capital cost, the steam and power balance in the related area, and the reliability in the refinery's power supply. Based on the authors' experience, the utilities' energy efficiency incentive programs in California also influence the decision-making process for turbine motorization projects. Therefore, this paper includes a description of the utilities' guidelines for fuel substitution projects. In particular, the utilities' three-prong requirements on net source-BTU energy savings, cost effectiveness, and avoidance of adverse impacts to the environment are discussed. Two real life case studies are presented to demonstrate how the above criteria should be applied for determining if a motorization opportunity is economically viable. A discussion on suggested features is also included for prescreening turbine motorization project candidates for better energy and environment economics such as venting of exhaust steam from a back pressure turbine and oversized design of the existing turbine and pump.

INTRODUCTION

Rotary machines are probably among the most frequently used energy consumers in the refineries. Compressors, pumps, blowers, and fans are all rotary machines and are found in any major petroleum refining process with installed horse power in excess of thousands. Whether they are driven by electric motors or steam turbines depends on the plant design and several other factors such as reliability, first cost, energy cost, and limitations of each technology.

Historically, reliability has always been the most dominant factor in refinery operations due to the extreme importance of maintaining stable production rates. In all industries, energy costs have always been less important than production costs, more so in the past because energy prices were a lot lower and the environmental requirements were less stringent. However, this trend is changing. Today, with the rise of energy price, more refineries are trying to increase their competitiveness in the market by lowering their energy cost index. Although an extensive amount of "free energy" is generated during the refining processes as a byproduct and is used as much as possible for process needs, the refineries still purchase a significant amount of electricity and natural gas from utilities to meet their total energy requirements. And because energy costs equal a substantial portion of the refineries' total operating costs, saving energy and purchasing less energy from the utilities is becoming a growing trend. .

It is not clear whether an electric motor or a steam turbine is a better choice of prime mover for rotary equipment because, as previously mentioned, performance and economics depend on a host of different factors. However, if the conditions are favorable, motorization can save a considerable amount of energy. Conversely, there are many examples in which the use of a steam turbine would make more sense. One such example is that many large refineries have a major combined heat and power plant (CHP) where high-pressure steam is generated to drive large turbines to generate electricity for local uses, with several levels of lower pressure steam piped around the refinery and used in various processes to drive rotary machines. In this example, the use of steam turbines may outweigh the

advantage of utilizing electric motors as prime movers since extra steam is available to run the different end-users. This paper is not intended to discuss the optimization of heat and power balance in a large refinery. However, every motorization project should consider the whole picture of steam and power balance.

MOTORIZATION IN LITERATURE

Over an expansive search, we only found two steam turbine motorization projects and associated studies in the literature review. Harish (1989) reviewed a motorization project at a petrochemical complex where 600# (psig) steam is expanded through a central back-pressure turbogenerator, pressure reducer valves (PRV), and a few smaller turbines, which are all tied into the same common header. An energy audit of the facility identified a replacement opportunity for the steam-turbine drive of a boiler's induced draft fan with an electric motor with variable frequency drive (VFD). The central turbogenerators provided electricity for the motor. The motorization project saved a 2,000-tonne coal equivalent of energy (tce) due to the improved overall "steam rate" of the plant (defined by Harish as the steam consumption of the turbine per unit of output power; i.e., lb of steam per kWh).

Since the 1980s, the VFD technology has been increasingly commercialized in industrial and commercial applications. The VFD's high efficiency performance at partial loads, good reliability provided with enough power supply redundancy and less maintenance compared to aging turbines have increased its popularity in the refinery facilities. Krattiger, et al. (2004) documented a successful application of steam turbine motorization with VFD on a 4000-hp blower of the FCCU (fluidized catalytic cracking unit) at a large refinery in Argentina. The economic factors considered in the feasibility study included first cost, energy cost, cooling water cost (for condensing turbine), and maintenance cost. Since the aged turbine speed controller had already lost functionality in this case, the proposed VFD achieved significant energy savings. The payback period of this project was about three years, with an estimated annual energy cost savings of $500,000. In addition, because of the turbine's age, purchase of a spare rotor would be required to ensure reliability, which added more value to motorization of the drive.

Note that even with the more advanced VFD technology today, motorization may not be the best choice in some refinery applications. Harish (1989) summarized the following situations where steam-turbine drives would be preferred or are the only option:

- Large power needs (a few MW or more)
- Replacing PRVs
- Harsh operating environment (e.g. non-sparking operation, corrosive atmosphere)
- Standby/emergency service
- Balancing the steam power system

SURVEYS: WHAT DO THE REFINERIES THINK ABOUT MOTORIZATION?

To better understand the potential bottlenecks in motorization projects, the authors conducted a phone survey of a few major refineries in northern California. The following questions were asked during the interview:

- Has your refinery completed any motorization projects in the recent years? Do you have plans for more projects?
- What are the refineries top concerns or considerations in developing a project?
- For which applications is a steam turbine or an electric motor a better choice?
- Has the refinery done any economic analysis on motorization? Are you interested in engineering help on steam balance analysis?

While some refineries are more proactive in reducing energy cost as evidenced by several motorization projects they have completed, others are more conservative due to the capital investment and risk in lowering reliability. From the equipment standpoint, both steam turbines and electric motors are considered reliable drives, although electric motors require less frequent checking and maintenance in general. In summary, the top factors in the refineries' considerations include:

- How critical is the related equipment? It was mentioned that pumps or blowers associated with process cooling and reboiling are more critical, whereas process feed, recirculation, blending, and shipping-related applications are less critical.
- How much are the energy savings and capital cost? Turbine motorization for larger turbines is considered expensive, plus the refinery production may be interrupted for a certain time period. Usually short payback periods, like a couple of years, may make a project more attractive. Back-pressure turbines with exhaust

steam being wasted and condensing turbines usually make better energy saving candidates.

- Steam balance is an important economic factor. If extra steam is available in the related area, motorization may not be the most cost-effective option.
- How much redundancy is available in the power supply? The redundancy depends on the number of independent feeders from utilities and local CHP plant(s). While some large refineries have a full size CHP plant that can meet 100% of the refinery's power demand and can be relied on for power supply in an event of a power outage, other refineries have a limited CHP plant size, or none at all. Although a steam turbine can be used as backup drive after motorization, the refinery may still not want to take on the risk because the steam boilers may not respond quickly enough to pick up the extra load during a power outage.

UTILTIY INCENTIVE PROGRAM RULES STUDY

Steam turbine motorization typically involves fuel substitution unless the steam is generated in an electric boiler. Whereas turbine motorization is observed as a qualified energy efficiency measure in the major investors owned utilities (IOU) incentive programs in California, the California Public Utilities Commission (CPUC) has placed an extra requirement for passing a three-prong test on any fuel substitution project (CPUC, 2008), including motorization. The three-prong test is intended to ensure that the proposed fuel-switching project does not degrade the environmental. In order to pass the three-prong test, the following three criteria must be met:

- Criterion I: The project does not increase source-BTU consumption. Retail energy in the form of electricity or natural gas is required to be converted into the BTU required to generate and deliver the energy to the site.
- Criterion II: The project must have a TRC (Total Resource Cost) and PAC (Program Administrator Cost) benefit-cost ratio of 1.0 or greater. This ratio is used to test the cost effectiveness of the fuel substitution project.
- Criterion III: The project must not adversely impact the environment. To quantify the impact, respondents should compare the environmental costs with and without the program using the most recently adopted values for residual emissions (CO_2 and NO_x) in the avoided cost rulemaking.

Of the three criteria, Criterion I is the pre-requisite, and can be manually verified by following procedures. Because the steam turbine motorization usually saves heating energy but consumes more electricity, Criterion I can be expressed with the following equations: :

Net source-BTU (therm) = Saved heating energy (therm) – Source heating energy to produce electricity (therm) > 0 (1)

Where

Source heating energy to produce electricity (therm) = Additionally consumed kWh * 3412 (Btu/hr per kWh) * Source-BTU factor / 100,000 (Btu per therm) (2)

"Saved heating energy" in Equation (1) is the avoided gross heating energy consumption that results from not using the steam turbine. The "additionally consumed kWh" in Equation (2) is the electricity consumption of the proposed electric motor. Note that the Source-BTU factor is applied when converting the additionally consumed electricity into the source-BTU consumption. This factor gives the ratio of the total energy consumed to generate the electricity at the power plant, to the energy that is actually received by the end users. Therefore, it accounts for the energy losses during electricity generation, distribution and transmission.

Criterion II and III can be expressed as:

TRC (or PAC) benefit-cost ratio = [Gas TRC (or PAC) benefits – Electric TRC (or PAC) penalties] / TRC (or PAC) costs (3)

Net CO_2/NO_x emission = Gas CO_2/NO_x emission reduction – Electric CO_2/NO_x emission increase (4)

CPUC has adopted the E3 Calculator developed by Energy Environmental Economics (E3) in performing the three-prong tests. The URL of the E3 Calculator and the adopted methodology are given in the reference section. Detailed procedures and equations to quantify Criterion II and III can be found in the E3 technical manual whose location is also listed in the reference section.

CASE STUDIES

The utility energy efficiency incentive programs for heavy-industrial customers in northern California have promoted more energy efficiency projects by

significantly reducing the costs and payback periods. In order to be eligible for a utility incentive, a steam turbine motorization project has to meet the above mentioned criteria in the 3-prong test as described above. A major refinery in northern California is considering meeting this criteria and adding several steam turbine motorization projects to their agenda of overall energy efficiency improvement. In this section, two similar motorization projects proposed in this Californian refinery were used as examples of successful and unsuccessful projects from an energy efficiency perspective. The successful and unsuccessful projects serve as a good reference point for potential project development at the refinery.

Background

A pressurized fire water system is piped throughout the refinery for fire emergency use. Based on the refinery's topography, the entire fire water system comprises a lower-level system, a higher-level system, a storage tank between the two levels and another storage tank at the end of the higher-level system. The water level in the two storage tanks is always maintained to ensure adequate pressure in the fire water system. In both the lower- and higher-level systems, there are three connected pumps to meet emergency capacity but only one pump, driven by a steam turbine, is running on a regular basis and serves as a jockey pump to keep the systems pressurized as required. However, in both the lower- and higher-level systems, the jockey pumps are significantly oversized and are not operating at their design points on the pump curves. The jockey pump motorization project for the lower-level system was completed in 2008, whereas the project for the higher-level system failed to show net energy savings and was canceled.

Case I:

In the lower-level fire water system, a 400-hp steam turbine-driven pump was replaced by a 125-hp electric pump equipped with variable frequency drive (VFD). The project yielded about 460,000 therms of equivalent annual source energy savings. The project's payback was one year with utility incentives.

The pre-existing 400-hp steam turbine driven pump (**Figure 1**) was manufactured in the 1950s and had been continuously running to keep the system pressurized. The turbine exhaust steam was vented to the atmosphere, wasting significant energy (**Figure 2**).

Figure 1 Pre-existing 400-hp steam turbine driven fire water pump

Figure 2 Pre-existing drive turbine exhaust steam vented to atmosphere on site

Other than emergency fire fighting use, water is also drawn from the system for daily maintenance, cleaning, and process needs in the refinery. Therefore, after installing the 125-hp electric pump (**Figure 3**), which has a design flow of 1,500 GPM, there will still be 1,100 hours per year when the water flow demand exceeds the maximum flow rate of the new jockey pump. As a result, the turbine pump has been retained as a stand-by pump in the post-retrofit system, and will be used to supplement the new pump when the demand for fire water exceeds 1,500 GPM. Another benefit from this project is having fuel variety that has increased the reliability in the refinery fire water pumping system. The installed VFD on the new pump also enabled efficient control in the frequent low-flow range operation in this particular application.

Figure 3 Installed 125-hp electric motor driven jockey pump

Figure 4 Existing turbine drive of the fire water pump, with exhaust steam recovered

The additional electricity consumption of the new electric jockey pump was converted to the equivalent source-BTU thermal energy usage via Equation (2), which was smaller than the thermal energy usage of the steam-driven pump. The net energy saving from this motorization project was approximately 460,000 therms per year. Energy savings and the three-prong test results are summarized in Table 2. Note that this motorization project was cost-effective, and resulted in Greenhouse Gas Emission reduction.

Case II:

The configuration in the higher-level system resembles the lower-level system with a 285-hp steam turbine driven pump operating as a jockey pump. 150# steam is throttled to 80#, and then expands in the turbine to 15# before exiting. However, in this case, the 15# turbine exhaust steam is recovered and used in the refinery instead of being vented into the atmosphere (**Figure 4**). The potential source energy savings from motorization were estimated based on the provided pump curve; minimum flow rate at which the existing pump had been operating; and the turbine data sheet. The calculation showed that after installing a correctly sized constant speed electric jockey pump, the source energy savings would be -5,000 therms. The project was declined due to the negative net energy savings.

Since the exiting steam is recovered by not using the turbine, the refinery will have to create the same amount of 15# steam by throttling or de-superheating higher pressure steam through PRVs to meet the #15 steam demand. In this case, only the enthalpy drop across the turbine represents the avoided heating energy in motorization, which is very small compared to the enthalpy contained in the recovered exhaust steam (less than 4%). The energy savings and three-prong test results for this project are summarized in Table 1.

Note that the source-BTU factor played an important role, without it the project would have shown positive savings. Even when it is not required by a utility incentive program to apply the source-BTU factor, the energy losses in power generation and distribution should be considered in energy saving evaluations, although a different source-BTU factor may make more sense for a particular project.

Comparison between the Two Cases

The above two cases both involve motorization of steam turbine driven pumps that are oversized for the application. In the baseline scenarios, the two pumps were operating at a low-load range by changing shaft rotation speed under turbine governor controls. In Case I, the turbine exhaust steam was vented to the atmosphere; in Case II, the exhaust steam was recovered. This difference in steam recovery was the fundamental reason why Case I saw significant savings but not Case II. Because Case I inefficiently used steam to drive the turbine, motorization saved source-BTU and passed the three-prong test.

In the post-retrofit scenarios for both cases, it was suggested that the pumps be replaced with much smaller size electric pumps. In Case I, VFD was

installed for flow modulation; in Case II, no VFD was proposed because the pump flow was stable at the minimum flow required by the pump. Therefore, the absence of VFD in Case II did not reduce the potential savings.

Table 1 Three-Prong Test Results on the Two Case Studies

	Net Source-BTU Savings (therm/yr)	Cost-Effectiveness Ratio		Emissions (tons/yr)	
		TRC	PAC	CO_2	NO_x
Case I	460,000	4.1	7.1	2,700	4.2
Case II	-5,000	-0.8	-6.7	-9	0.1

CONCLUSIONS

This paper discussed the opportunities for replacing rotary machines' steam-turbine drivers with electric motors for greater energy efficiency in refineries. The steam turbine and electric motor technologies were compared in terms of reliability, maintenance, energy efficiency, and costs through the literature review and refinery survey. The survey results reveal that in considering a potential turbine motorization project, the refineries usually consider the following factors: critical level of the related equipment, potential energy savings and capital cost, steam and power balance in the related area, and reliability in their power supply. Considering the profound impact of existing utilities' incentive programs in California, the applied utility energy efficiency program rules were discussed in detail. In particular, turbine motorization projects have to pass the three-prong test (save source-BTU consumption, pass cost-benefit tests and reduce pollutant emission) in order to be eligible for incentives. Of all three criteria, reducing the source-BTU consumption is the most fundamental. Based on this discussion, not every turbine motorization project saves source energy. Furthermore, the more the source-BTU a motorization project saves, the higher the cost-effectiveness and pollution reduction capability.

Based on the two case studies presented in this paper and combined source of information from the literature review and refinery survey, we have identified several indicators for better energy and environment economics. These indicators may be used to prescreen candidates for motorization projects. Some examples of the indicators include whether the exhaust steam from a backpressure turbine is vented, whether the existing turbine and pump are oversized and operating at low-efficiency range, whether turbine governor control is in working condition, and whether the turbines are condensing turbines.

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U.S. Department of Energy's Advanced Manufacturing Office and Its Impacts

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ABSTRACT

The U.S. Department of Energy's Advanced Manufacturing Office (AMO), formerly the Industrial Technologies Program, has been working with industry since 1976 to encourage the development and adoption of new, energy-efficient technologies. AMO has helped industry not only use energy and materials more efficiently but also improve environmental performance, product quality, and productivity.

To help AMO determine the impacts of its programs, Pacific Northwest National Laboratory (PNNL) periodically reviews and analyzes AMO program benefits. PNNL contacts vendors and users of AMO-sponsored technologies that have been commercialized, estimates the number of units that have penetrated the market, conducts engineering analyses to estimate energy savings from the new technologies, and estimates air pollution and carbon emission reductions. This paper discusses the results of PNNL's most recent review (conducted in 2011). From 1976-2010, the commercialized technologies from AMO's research and development programs and other activities have cumulatively saved 10.7 quadrillion Btu, with a net cost savings of $56.5 billion.

INTRODUCTION

Working in partnership with industry, the U.S. Department of Energy's (DOE's) Advanced Manufacturing Office (AMO), previously the Industrial Technologies Program, conducts research, development, demonstration, and technical assistance efforts that are producing substantial, measurable benefits to industry. This paper summarizes some of the quantifiable impacts of AMO's programs through 2010. The Pacific Northwest National Laboratory (PNNL), operated by Battelle for DOE, assists AMO by tracking the results of its programs and quantifying the energy, environmental, and other benefits of the technologies once they penetrate the market. The following sections provide background information about industrial energy use, describe AMO's strategy and organization, describe the methodology used to track the program's benefits, and summarize the results of the most recent tracking exercise.

INDUSTRIAL ENERGY USE

Industry is the largest and most diverse energy-consuming sector in the U.S. economy. In 2010, the industrial sector used 30.14 quadrillion Btu (quad) of all types of energy (31% of the 98.0 quad used by the

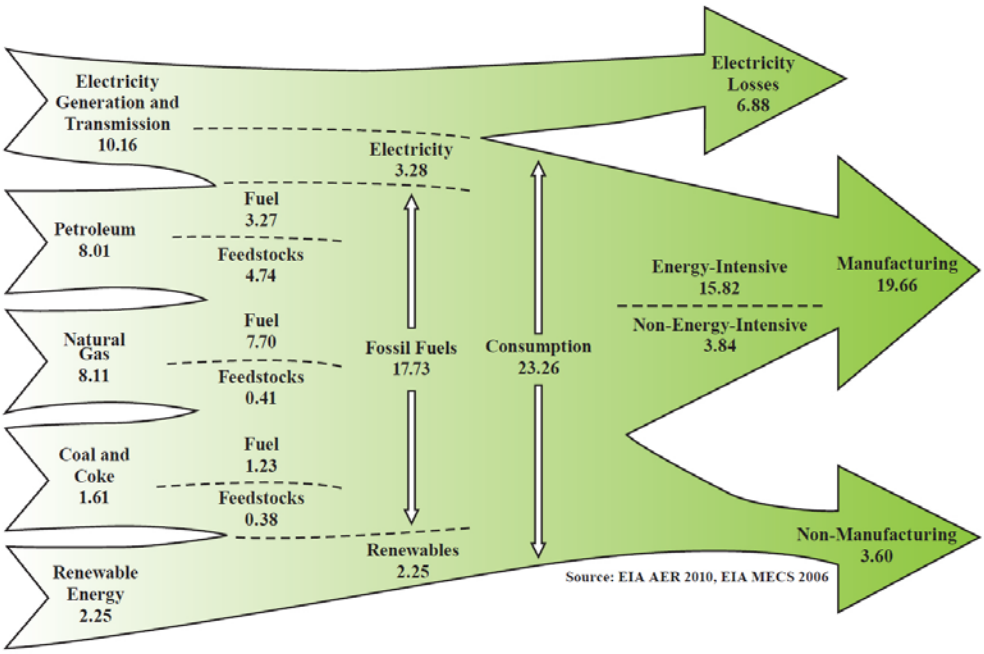


Figure 1. Industrial Energy Flows (Quad), 2010

entire economy), including electricity losses of 6.88 quad (see Figure 1).

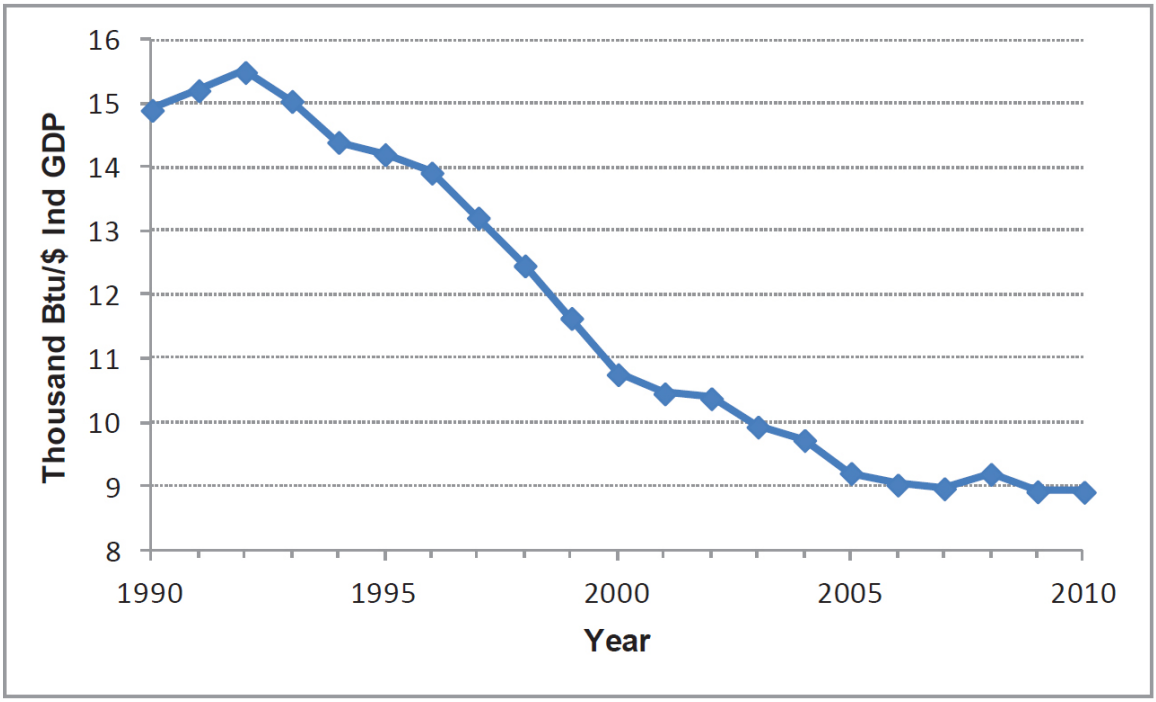
Petroleum (8.01 quad), natural gas (8.11 quad), and electricity (3.28 quad delivered) are the three fuels most used by industry, with coal and biomass providing another 3.86 quad combined. The industrial sector consumed 23.26 quad, of which 19.66 quad were consumed by manufacturing industries. Of that 19.66 quad, energy-intensive industries consumed 15.82 quad. The non-energy-intensive industries (3.84 quad) and nonmanufacturing industries (agriculture, mining, and construction – 3.60 quad combined) accounted for the remaining energy consumption. Industry used 5.53 quad of the fossil fuels for feedstocks – raw materials for plastics and chemicals – rather than as fuels.

Energy-intensive industries such as forest products, chemicals, petroleum refining, nonmetallic minerals (glass and cement, especially), and primary metals account for about 80% of all manufacturing energy use. Many of the energy-intensive industries are limited in their choice of fuels because the technologies currently used in specific processes require a certain fuel. For example, aluminum production requires large amounts of electricity to reduce the alumina to metal. Paper pulping leaves a large residual of wood lignin that can be reprocessed for its chemical content and consequently supplies the industry with half of its primary energy. Therefore, the wide variety of fuels (and feedstocks) used in the industrial sector partially reflects the specific requirements of the processes used to make particular goods or commodities. Because of these energy requirements, the industrial sector offers a wide variety of opportunities for energy-efficiency improvements that are specific to particular industries or that crosscut many industries (i.e., are common to many industries or are needed by many process-specific technologies).

The energy intensity of the industrial sector has been declining over the past decade, in part because of investments in the development of energy-efficient technologies by AMO, previously the Industrial Technologies Program (ITP). Since its peak in 1992, industrial sector energy intensity has declined more than 40%, from 15,500 Btu/dollar of real industrial GDP to 8,900 Btu/dollar of real industrial GDP in 2010 (see Figure 2).

THE ADVANCED MANUFACTURING OFFICE

AMO is the lead government program working to develop and deploy new, energy-efficient technologies for the U.S. manufacturing sector. Programs within AMO are tailored to address specific barriers faced by technology developers and manufacturers to ensure that cost-effective technologies are effectively transitioned from fundamental to applied research, developed into commercially available products, and effectively deployed where they are demanded throughout U.S. supply chains.



Sources: EIA Annual Energy Review, 2010, Table 2.1d and BEA, Value Added for Industry, 1990-1997 and 1998-2010, *(Constant $2010)*

Figure 2. Historical Industrial Energy Intensity

Strategic Approach

The United States has a strong foundation in early-stage basic research focused on identifying promising technologies with high technical potential. However, much of this research has not been successfully developed into commercially available products. Many opportunities stall in the later development and demonstration stages, known as the "Technology Valley of Death." In addition, some commercially available technologies remain under-deployed even after cost savings are demonstrated. To address these challenges, AMO programs adhere to the following principles:

- Support technologies that are broadly applicable, pervasive, pre-competitive, and relevant across manufacturing sectors including clean energy.
- Support technologies at a scale that is meaningful to manufacturers.
- Support keystone technologies with the ability to have a wider impact relative to other alternatives.
- Support technologies with the potential to reduce energy use across product life cycles by 50% over 10 years compared with incumbent technologies (averaged across the research, development, and deployment (RD&D) portfolio).
- Support manufacturers through effective and novel public-private partnership and collaborative models (federal, state, local, industry, academia) that leverage non-federal resources to address the causes of market or government failures related to advanced manufacturing technologies.
- Support existing U.S. manufacturers through technology deployment efforts that are targeted at specific barriers to adoption for energy-efficient technologies.
- Support and align with national goals and initiatives such as the Advanced Manufacturing Partnership, Better Buildings, Better Plants, and the Materials Genome Initiative.

Organization

The Office is divided into three primary areas: Research & Development, Technology Deployment, and Manufacturing Energy Systems Partnerships.

Research & Development

AMO R&D funding moves innovative, pre-competitive projects along the technology pipeline. The goal of this funding is to support applied R&D through manufacturing-scale demonstration—bridging the traditional "Valley of Death" for emerging technologies. The two primary focuses of AMO's R&D are next-generation manufacturing processes and next-generation materials.

Next-generation manufacturing processes reinvent and collapse processing steps to reduce the energy intensity of manufactured products. Process technology areas that AMO is currently focused on include:

- Reactions and Separations: New technologies that provide high energy efficiency and process intensification can yield dramatic energy and cost savings in a range of industries, including oil refining, food processing, and chemical production. Example technologies include separation processes that rely on high-performance membranes and catalysts.
- High-Temperature Processing: Non-thermal or lower-energy alternatives to conventional, high-temperature processing technologies will enable more efficient production or recovery of critical materials (metallic and non-metallic). Such technologies could enable or enhance water-based, selective extraction of critical materials from low-grade ores; recovery of high-value materials in obsolete electronic equipment and waste; and low-temperature, high-efficiency chemical or electrochemical processes.
- Waste Heat Minimization and Recovery: Technology advances in ultra-efficient steam production, high-performance furnaces, and innovative waste-heat recovery will help to improve sustainability, reduce water usage, and decrease the energy footprint of U.S. manufacturing.

- Sustainable Manufacturing: New manufacturing technologies that reduce process steps, materials usage, or part counts will reduce the energy embedded in the manufacturing value chain and decrease the use of raw materials in multiple markets. The same is true of technologies that enable the manufacture of materials or components that increase recycling and recyclability. Upon initial product conceptualization, new design and process tools could enable selection of a manufacturing process to meet specific cost, time, energy intensity, and life-cycle energy consumption requirements.

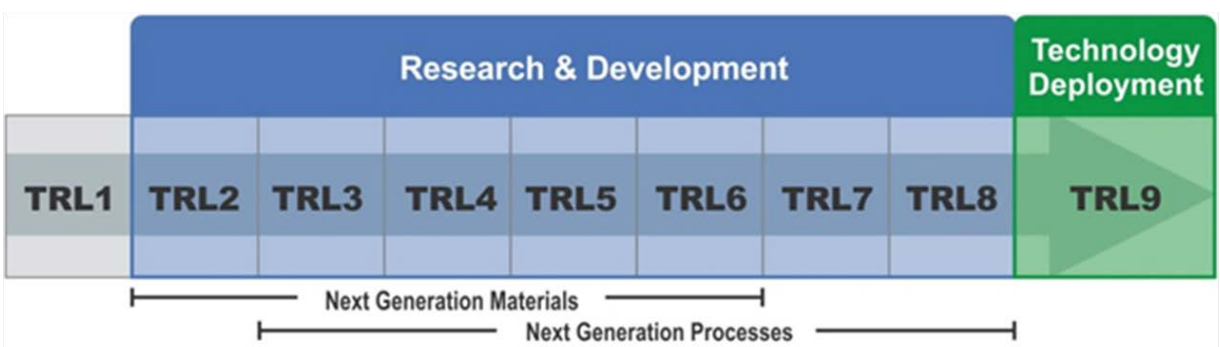
Next-generation materials provide new functional properties that reduce energy consumption and enable the development of new high-performance products. AMO's R&D portfolio of promising materials technologies includes the following categories:

- Thermal and Degradation Resistant Materials: Innovative materials that are more durable in high-temperature environments than traditional materials will improve productivity, avoid down time, and increase energy productivity. The goal is to increase service life tenfold, decreasing the energy intensity of the materials and components.
-

- Highly Functional, High-Performance Materials: Advanced industrial materials deployed in energy production and energy transfer equipment can improve the performance of that equipment by 50% or more. Examples include advanced composites, hybrid materials, engineered polymers, and low-density/high-strength metals or alloys.

- Lower-Cost Materials for Energy Systems: The development and manufacture of materials that offer improved functional properties at low cost can cut the cost of finished products by half. Examples include lower-cost photovoltaic materials and wind system components, electrochemical and thin-film materials, refractories and insulation materials, and materials for heat exchangers or other waste heat recovery technologies.

The technology readiness level (TRL) system is used by AMO to guide decision-making throughout the technology development process. AMO conducts cost-shared R&D on projects at TRL levels 2 through 8, where high technical risk may deter private investment. AMO also conducts outreach at TRL 9 to accelerate the market uptake of energy-efficient technologies and management practices, where market risks displace technical risks. Figure 3 shows the TRL-based technology progression categories supported by AMO.



Innovation
TRL 1 – Basic Research
TRL 2 – Applied Research
TRL 3 – Critical Function or Proof of Concept Established

Emerging Technologies
TRL 4 – Laboratory Testing/Validation of Component(s)/Process(es)
TRL 5 – Laboratory Testing of Integrated/Semi-Integrated System
TRL 6 – Prototype System Verified

Systems Integration
TRL 7 – Integrated Pilot System Demonstrated
TRL 8 – System Incorporated in Commercial Design

Market Penetration
TRL 9 – System Proven and Ready for Full Commercial Deployment

Figure 3. TRL Technology Progression

Technology Deployment

As technologies proceed along the development pipeline, most face major hurdles as they attempt to enter commercial markets. AMO's technology deployment programs help lower a range of institutional barriers and prepare energy-efficient technologies and energy management systems for full commercial deployment. These activities, which address barriers associated with TRL 9, include the following:

- The Better Buildings, Better Plants Challenge and Program, which promote corporate partners who demonstrate their commitment to energy savings and share experiences in order to foster replication.

- The Superior Energy Performance certification program, which provides a platform for measuring, certifying, and recognizing energy savings achieved by facilities that conform to the ISO 50001 Energy Management Standard. This platform supports Better Plants partners in meeting their energy savings goals.

- Software tools that are available at no cost to help companies identify and analyze opportunities to save energy in manufacturing.

- A network of Industrial Assessment Centers (IACs) that train engineering students to perform energy audits for small- and mid-sized manufacturers. The students gain valuable experience as energy management professionals and provide useful feedback on the real-world application of AMO tools.

- Collaborative partnerships with federal agencies, state and local governments, utilities, universities, national laboratories, and industry trade associations.

- Clean Energy Application Centers that provide outreach to manufacturers considering adoption of combined heat and power (CHP) technologies in order to save energy and money.

- Energy Experts and Qualified Specialists who are available to help manufacturers use DOE software tools and resources.

Manufacturing Energy Systems Partnerships

In addition to R&D and Technology Deployment activities, AMO is also supporting three knowledge development and dissemination centers that will help solve critical manufacturing issues and accelerate the most promising clean-energy technologies into full-scale manufacturing.

AMO's website (http://www.eere.energy.gov/manufacturing) provides a wealth of information about the program, and the EERE Information Center (1-877-337-3463, eereic@ee.doe.gov) fields questions and facilitates access to AMO resources for industrial customers.

HOW BENEFITS ARE QUANTIFIED

AMO program managers recognize the importance of developing accurate data on the impacts of their programs. Such data are essential for assessing AMO's past performance and guiding the direction of future research programs.

PNNL estimates energy savings associated with specific technologies using a rigorous process for tracking and managing data. When a full-scale commercial unit of a technology is operational in a commercial setting, that technology is considered commercially successful and is on the active tracking list. When a commercially successful technology unit has been in operation for about ten years, that unit is then considered a mature technology and typically is no longer actively tracked. The active tracking process involves collecting technical and market data on each commercially successful technology, including details on the following:

- Number of units sold, installed, and operating in the United States and abroad (including size and location)

- Units decommissioned since the previous year

- Energy saved

- Environmental benefits

- Improvements in quality and productivity

- Other impacts such as employment and effects on health and safety

- Marketing issues and barriers.

Information on technologies is gathered through direct contact with either vendors or end users of the technology. These contacts provide the data needed to calculate the unit energy savings associated with an individual technology, as well as the number of operating units. Therefore, unit energy savings are calculated in a unique way for each technology. Technology manufacturers or end users usually provide unit energy savings or at least enough data for a typical unit energy savings to be calculated. The total number of operating units is equal to the number of units installed minus the number of units decommissioned or classified as mature in a given year – information usually determined from sales data or end user input. Operating units and unit energy savings can then be used to calculate total annual energy savings for the technology.

The cumulative energy savings represent the accumulated energy saved for all units for the total time the technology has been in operation. This includes previous savings from now-mature units and decommissioned units, even though these units are not included in the current year's savings.

Once cumulative energy savings have been determined, long-term impacts on the environment are calculated by estimating the associated reduction of air pollutants. This calculation is based on the type of fuel saved and the pollutants typically associated with combustion of that fuel and uses assumed average emission factors. For example, for every million Btu of coal combusted, about 1.25 pounds of sulfur oxides (known acid rain precursors) are assumed to be emitted to the atmosphere. Therefore, every million-Btu reduction in coal use eliminates 1.25 pounds of sulfur oxides.

The cumulative production cost savings minus the cumulative AMO appropriations and implementation costs provide an estimate of the direct **net** economic benefit of the AMO program since its inception. The program's benefits are based on the following:

Estimated energy savings – Since the program began in 1976, the energy savings (Btu) produced by AMO -supported, commercialized technologies have been tracked. As of 2010, the cumulative value for energy savings of all commercial and historical AMO technologies was 3.73 quad.

The cost of industrial energy saved – The nominal prices (in dollars per million Btu) for various fuels are reported in the Energy Information Administration's Annual Energy Review (AER). Nominal fuel prices extending back in time from 2010 to 1978 were obtained from the 2010 AER. These prices are adjusted for inflation based on an index of all fuels and power as reported by the Bureau of Labor Statistics, but normalized to 2010 so that all prices are in current dollars. These real annual fuel prices are multiplied by the amount of energy saved per fuel type per year for each of the AMO commercialized and tracked technologies.

The program's costs are based on the following:

ITP appropriations – Appropriations are R&D dollars spent by AMO each year since the program began. As of FY 2010, the cumulative AMO spending since 1976 is $3.24 billion. The appropriations are adjusted for inflation by using the implicit price deflator for non-defense federal government expenditures, as published by the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce.

Assumed cost of implementation – Because reliable information about the costs of installing the new technologies is not available, an assumption was made to account for these costs. Industry is assumed to require a two-year payback period on investments. To account for implementation costs, the first two years of the cumulated energy savings for each technology are ignored because these saving are needed to "recoup" the capital costs of adopting the new technology. Again, these costs are adjusted for inflation just as are the fuel prices for savings.

For each technology, the annual energy savings by fuel type are multiplied by the real price of that fuel. The sum of all energy saved times the average real energy price yields an estimate of the annual savings for all technologies in that particular year. In addition to technology energy savings, savings from two technology delivery programs, the Industrial Assessment Centers (IACs) and the Save Energy Now Initiative, and CHP activities were also determined on an annual basis.

The economic benefits are the accumulation of these savings over time adjusted for inflation, as described above. The economic costs are two-fold:

AMO appropriations and the implementation costs reflected in the two-year payback period. As mentioned above, the appropriations are adjusted for inflation with the BEA's implicit price deflator for non-defense federal government expenditures. The implementation costs are adjusted for inflation in the same manner as fuel savings. The net economic benefits are then the benefits minus the costs.

Several factors make the tracking task challenging. Personnel turnover at developing organizations and at user companies makes it difficult to identify applications. Small companies that develop a successful technology may be bought by larger firms or may assign the technology rights to a third party. As time goes on, the technologies may be incorporated into new products, applied in new industries, or even replaced by newer technologies that are derivative of the developed technology.

Program benefits documented by PNNL are conservative estimates based on technology users' and developers' testimonies. These estimates do not include either derivative effects, resulting from other new technologies that spin off of AMO technologies, or the secondary benefits of the energy and cost savings accrued in the basic manufacturing industries downstream of the new technologies. Therefore, actual benefits are likely to be much higher than the numbers reported here. Nonetheless, the benefits-tracking process provides a wealth of information on the program's successes.

RESULTS of ITP R&D

AMO's R&D has resulted in over 260 successfully commercialized technologies. In addition to technology energy savings, savings from the IACs, the Save Energy Now Initiative, and CHP activities are also determined annually. Table 1 provides information on all the commercialized technologies currently tracked. The table shows energy savings in 2010, as well as cumulative energy savings and pollution reductions. Note that for some technologies, energy savings values are unavailable or too difficult to quantify. In 2010, these commercialized technologies and the IACs, the Save Energy Now Initiative, and CHP activities saved more than 710 trillion Btu (estimated annual savings), which translates to a $5.12 billion savings to industry. While the energy savings are impressive, industry has reaped even greater benefits from the productivity improvements, reduced resource consumption, decreased emissions, and enhancements to product quality associated with these technological advances. The cumulative emission reductions associated with these commercialized technologies and AMO programs are estimated to equal 236 million tons of carbon, 2.02 million tons of NO_x, and 4.28 million tons of SO_x. In addition, many AMO-supported projects have significantly expanded the basic knowledge about complex industrial processes and laid the foundation for developing future energy-efficient technologies.

Figure 4 shows the net benefits curve (described in the previous section) for AMO. The values shown for each year represent the cumulative energy savings (in dollars) of all the technologies and programs, minus the cost of installing the technologies (assuming a two-year payback as described earlier) and also subtracting AMO's cumulative programmatic costs. Cumulatively, since 1976, AMO's commercialized technologies and programs have saved 10.7 quad of energy and $56.5 billion.

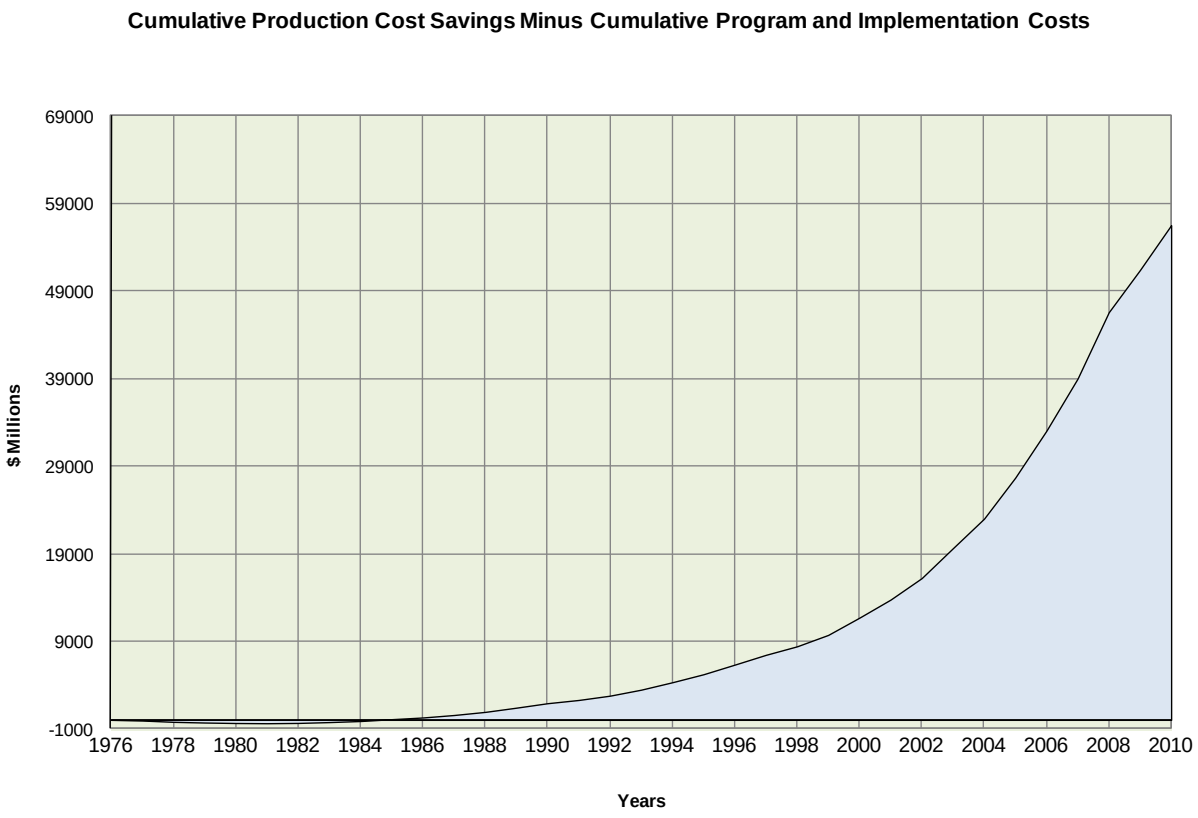


Figure 4. Cumulative Production Cost Savings Minus Cumulative Program and Implementation Costs

Table 1. AMO Technology Program Impacts

Technologies Commercially Available	Cumulative Energy Savings (10^{12} Btu)	Current 2010 Energy Savings (1012 Btu)	Cumulative Pollution Reductions (Thousand Tons)				
			Particulates	VOCs	SOx	NOx	Carbon
ALUMINUM							
Aluminum Reclaimer for Foundry Applications	0.005	0.001	-	0.000	-	0.001	0.076
Isothermal Melting	0.013	0.003	0.000	0.000	0.011	0.004	0.555
CHEMICALS							
Cavity-Enhanced Gas Analyzer for Process Control	-	-	-	-	-	-	-
Hollow-Fiber Membrane Compressed Air Drying System	0.033	0.012	0.000	0.000	0.007	0.005	0.642
Improved Methods for the Production of Polyurethane Foam	0.413	0.117	0.001	0.001	0.044	0.057	7.33
Low-Cost, Robust Ceramic Membranes for Gas Separation	0.063	0.020	-	0.000	-	0.007	1.000
Low-Frequency Sonic Mixing Technology	-	-	-	-	-	-	-
Membranes for Reverse-Organic Air Separations	0.424	0.150	0.003	0.002	0.246	0.065	9.23
Mixed Solvent Electrolyte Model	-	-	-	-	-	-	-
Nylon Carpet Recycling	1.72	0.398	-	0.006	-	0.201	27.3
Pressure Swing Adsorption for Product Recovery	0.737	0.111	-	0.003	-	0.086	11.70
Process Heater for Stoichiometric Combustion Control	2.86	0.411	0.002	0.010	0.169	0.352	47.4
Titania-Activated Silica System for Emission Control	-	-	-	-	-	-	-
Total Cost Assessment Tool	-	-	-	-	-	-	-
TruePeak Process Laser Analyzer	-	-	-	-	-	-	-
FOREST PRODUCTS							
Advanced Quality Control (AQC) Solution for Thermo-Mechanical Pulping	1.50	0.231	0.007	0.005	0.324	0.241	29.5
Biological Air Emissions Control	2.41	0.825	0.000	0.008	0.008	0.284	38.4
Borate Autocastizing	0.035	-	0.000	0.000	0.020	0.005	0.766
Continuous Digester Control Technology	9.00	-	-	0.032	-	1.05	143
Detection and Control of Deposition on Pendant Tubes In Kraft Chemical Recovery Boilers	9.17	1.99	0.069	0.041	5.33	1.42	200
MultiWaveTM Automated Sorting System for Efficient Recycling	-	-	-	-	-	-	-
Screenable Pressure-Sensitive Adhesives	-	-	-	-	-	-	-
ThermodyneTM Evaporator – A Molded Pulp Products Dryer	0.555	0.079	-	0.002	-	0.065	8.81
GLASS							
High Luminosity, Low-NOx Burner	-	-	-	-	-	-	-
High Throughput Vacuum Processing for Producing Innovative Glass/Photovoltaic Solar Cells	-	-	-	-	-	-	-
Process for Converting Waste Glass Fiber into Value-Added Products	0.525	0.140	-	0.002	-	0.061	8.33
METAL CASTING							
CFD Modeling for Lost Foam White Side	-	-	-	-	-	-	-
Die Casting Copper Motor Rotors	0.552	0.163	0.002	0.002	0.119	0.089	10.85
Improved Magnesium Molding Process (Thixomolding)	0.298	0.075	-	0.001	-	0.035	4.73
Improvement of the Lost Foam Casting Process	2.45	0.163	0.005	0.009	0.227	0.332	42.8
Low Permeability Components for Aluminum Melting and Casting	-	-	-	-	-	-	-
Titanium Matrix Composite Tooling Material for Aluminum Die Castings	0.087	0.019	-	0.000	-	0.010	1.38
MINING							
Belt Vision Inspection System	-	-	-	-	-	-	-
Digital Through-the-Earth Communication™ System	-	-	-	-	-	-	-
Horizon SensorTM	0.251	-	0.001	0.001	0.054	0.040	4.93
Imaging Ahead of Mining	7.14	-	0.032	0.025	1.54	1.15	140
Lower-pH Copper Flotation Reagent System	5.84	0.973	0.026	0.020	1.26	0.940	114.8
STEEL							
Aluminum Bronze Alloys to Improve Furnace Component Life	0.075	0.006	-	0.000	-	0.009	1.18
Automated Steel Cleanliness Analysis Tool (ASCAT)	-	-	-	-	-	-	-
Electrochemical Dezincing of Steel Scrap	0.407	0.036	0.005	0.000	0.255	0.114	11.4
HotEye® Steel Surface Inspection System	9.82	1.530	-	0.034	-	1.149	156
H-Series Cast Austenitic Stainless Steels	0.001	0.000	-	0.000	-	0.000	0.011
ITmk3: High-Quality Iron Nuggets Using a Rotary Hearth Furnace	0.329	0.329	0.003	0.001	0.147	0.077	8.059
Laser Contouring System for Refractory Lining Measurements	-	-	-	-	-	-	-
Life Improvement of Pot Hardware in Continuous Hot Dipping Processes	-	-	-	-	-	-	-
Low-Temperature Colossal Supersaturation of Stainless Steels	-	-	-	-	-	-	-
Microstructure Engineering for Hot Strip Mills	-	-	-	-	-	-	-
Vanadium Carbide Coating Process	0.000	-	-	0.000	-	0.000	0.000

Table 1. AMO Technology Program Impacts-Continued

Technologies Commercially Available	Cumulative Energy Savings (10^{12} Btu)	Current 2010 Energy Savings (1012 Btu)	Cumulative Pollution Reductions (Thousand Tons)				
			Particulates	VOCs	SOx	NOx	Carbon
CROSSCUTTING							
Adjustable-Speed Drives for 500 to 4000 Horsepower Industrial Applications	2.20	0.551	0.010	0.008	0.476	0.354	43.3
Advanced Aerodynamic Technologies for Improving Fuel Economy in Ground Vehicles	0.152	0.059	0.001	0.001	0.088	0.023	3.31
Advanced Diagnostics and Control for Furnaces, Fired Heaters and Boilers	-	-	-	-	-	-	-
Advanced Reciprocating Engine Systems (ARES)	-	-	-	-	-	-	-
Aerogel-Based Insulation for Industrial Steam Distribution Systems	0.537	0.374	-	0.002	-	0.063	8.52
Autotherm® Energy Recovery System	0.178	0.040	0.001	0.001	0.103	0.027	3.87
Barracuda Computational Particle Fluid Dynamics (CPFD) Software	-	-	-	-	-	-	-
Callidus Ultra-Blue (CUB) Burner	123.9	28.8	-	0.434	-	14.5	1,966
Catalytic Combustion	-	-	-	-	-	-	-
Composite-Reinforced Aluminum Conductor	-	-	-	-	-	-	-
Cromer Cycle Air Conditioner	1.67	0.541	0.007	0.006	0.360	0.268	32.8
Electrochromic Windows - Advanced Processing Technology	0.004	0.002	0.000	0.000	0.001	0.001	0.077
Energy-Conserving Tool for Combustion-Dependent Industries	0.029	0.007	0.000	0.000	0.006	0.005	0.566
Fiber Sizing Sensor and Controller	-	-	-	-	-	-	-
Fiber-Optic Sensor for Industrial Process Measurement and Control	-	-	-	-	-	-	-
Force Modulation System for Vehicle Manufacturing	0.045	0.029	0.000	0.000	0.013	0.009	0.969
Freight WingTM Aerodynamic Fairings	2.229	1.518	0.017	0.010	1.295	0.344	48.5
Functionally Graded Materials for Manufacturing Tools and Dies	-	-	-	-	-	-	-
Ice Bear® Storage Module	0.004	0.001	0.000	0.000	0.001	0.001	0.079
In-Situ, Real Time Measurement of Elemental Constituents	0.927	-	-	0.003	-	0.108	14.7
Materials and Process Design for High Temperature Carburizing	-	-	-	-	-	-	-
Mobile Zone Optimized Control System for Ultra-Efficient Surface-Coating	0.066	0.007	0.000	0.000	0.006	0.009	1.14
Nanocoatings for High-Efficiency Industrial Hydraulic and Tooling Systems	-	-	-	-	-	-	-
Novel Refractory Materials for High-Temperature, High-Alkaline Environments	-	-	-	-	-	-	-
Portable Parallel Beam X-Ray Diffraction System	-	-	-	-	-	-	-
Predicting Corrosion of Advanced Materials and Fabricated Components	-	-	-	-	-	-	-
Process Particle Counter	-	-	-	-	-	-	-
Pulsed Laser Imager for Detecting Hydrocarbon and VOC Emissions	2.30	0.535	-	0.008	-	0.269	36.5
Self-Healing Polymeric Coatings	-	-	-	-	-	-	-
Simple Control for Single-Phase AC Induction Motors in HVAC Systems	-	-	-	-	-	-	-
Solid-State Sensors for Monitoring Hydrogen	-	-	-	-	-	-	-
SpyroCorTM Radiant Tube Heater Inserts	10.04	2.58	-	0.035	-	1.175	159
Three-Phase Rotary Separator Turbine	0.036	-	0.000	0.000	0.008	0.006	0.704
Ultra-Low NOX Premixed Industrial Burner	-	-	-	-	-	-	-
Ultrananocrystalline Diamond (UNCD) Seal Faces	-	-	-	-	-	-	-
Vibration Power Harvesting	-	-	-	-	-	-	-
Wireless Sensor Network for Motor Energy Management	-	-	-	-	-	-	-
Wireless Sensors for Condition Monitoring of Essential Assets	-	-	-	-	-	-	-
Wireless Sensors for Process Stream Sampling and Analysis	-	-	-	-	-	-	-
OTHER INDUSTRIES							
Advanced Membrane Devices for Natural Gas Cleaning	-	-	-	-	-	-	-
Data Center Transformer from "Always On" to "Always Available"	-	-	-	-	-	-	-
Deep-Discharge Zinc-Bromine Battery Module	-	-	-	-	-	-	-
Energy-Efficient Cooling Control Systems for Data Centers	-	-	-	-	-	-	-
High-Efficiency, Wide-Band Three-Phase Rectifiers and Adaptive Rectifier Management	-	-	-	-	-	-	-
High-Intensity Silicon Vertical Multi-Junction Solar Cells	-	-	-	-	-	-	-
Long Wavelength Catalytic Infrared Drying System	0.015	0.003	-	0.000	-	0.002	0.231
Low-Volume Server for Reduced Energy Use and Facility Space Requirements	-	-	-	-	-	-	-
Management Technology for Energy Efficiency in Data Centers and Telecommunications Facilities	0.154	0.154	0.001	0.001	0.033	0.025	3.027
Plant Phenotype Characterization System	-	-	-	-	-	-	-
Plastic or Fibers from Bio-Based Polymers	0.142	0.018	0.001	0.001	0.082	0.022	3.09
Commercial Technologies Total	201	43.0	0.20	0.72	12	25	3,357
IAC Total	2,443	241	11.7	8.96	772	374	48,463
Save Energy Now Total	1,579	214	7.53	5.83	501	240	31,284
CHP Total	2,963	215	38.1	3.26	1,851	819	82,372
Historical Technologies Total	3,527	-	17.77	22.3	1,144	558	71,012
GRAND TOTAL	**10,714**	**713**	**75.2**	**41.0**	**4,280**	**2,016**	**236,487**

MEPs AS AN ENERGY EFFICIENCY CHANNEL

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ABSTRACT

Though the Small-to-Medium Industrial (SMI) sector accounts for 42% of US manufacturing energy use, this sector has historically been a difficult group to engage in energy efficiency. The Northwest Energy Efficiency Alliance (NEEA) has begun expanding approaches in the SMI sector through a number of efforts. NEEA's most recent effort is the Manufacturing Extension Partnership (MEP) Support Project. This paper provides an overview of the MEP Support Project, including results and findings from engagement with Idaho TechHelp, Oregon Manufacturing Extension Partnership, Montana Manufacturing Extension Center and Impact Washington, as well as Impact Washington's partner, the Washington State Department of Ecology. The paper also outlines the core energy savings approaches deployed. Finally, the paper provides recommendations on how to engage MEP consultants as energy agents for the benefit of the SMI sector in the Northwest region as well as in other parts of the country.

INTRODUCTION

According to the US Department of Energy, there are about 196,000 small to medium-sized manufacturing facilities in the US (6).[1] Though these facilities account for 42% of total US manufacturing energy use, they are often underserved in the energy efficiency market (6). Indeed, government agencies, utilities, and third-party program administrators typically rely on energy efficiency programs targeting the residential/commercial mass market and customized large industrial sectors to achieve energy savings. Unfortunately, it is typically not cost effective to apply consultative resources to the small facilities of the industrial sector. Conversely, a mass market approach does not deliver the level of service and support needed to produce the desired long-term energy saving solutions that are required by energy efficiency programs. A few program administrators have begun to innovate with specific approaches for the small-to-medium industrial (SMI) sector, such as simplified forms for smaller industrial energy saving projects. However, there have not been targeted outreach programs for smaller industrial facilities. Consequently, new ways to cost-effectively target and advance energy performance in the SMI sector are needed.

The Northwest Energy Efficiency Alliance (NEEA) has begun expanding approaches in the SMI sector through a number of efforts (1, 2). NEEA previously gained traction in the medium-to-large industrial sector, with proven results in taking the concepts of Strategic Energy Management (SEM) into medium-to-large industrial facilities under the brand name Continuous Energy Improvement (CEI). The CEI effort has led to Northwest energy efficiency program administrators, Energy Trust of Oregon (ETO) and Bonneville Power Administration (BPA), adding SEM services to their portfolio of offerings.

Most recently, NEEA industrial staff recognized the challenge of the lack of "right-sized" consultants who can assist SMI facilities with energy efficiency opportunities. To address this gap, NEEA initiated conversations with the Manufacturing Extension Partnerships (MEPs) in the Northwest to identify ways of leveraging MEP consultants as agents of energy efficiency in the SMI sector. Specifically, NEEA had discussions with the Oregon Manufacturing Extension Partnership (OMEP) to establish the shared goal of looking for opportunities

[1] US Department of Energy defines a small industrial facility as a manufacturing facility that uses less than 25 billion Btu/year (about <$100,000/year in energy costs) and a medium-sized industrial facility as one that uses more than 25 billion Btu/year but less than 500 billion Btu/year (about $100,000 to $3,000,000/year in energy costs).

to collaborate. One effort borne out of these discussions is NEEA's MEP Support Project.

This paper begins by providing a background on the MEPs and their typical characteristics. It then discusses the major components of the NEEA MEP Support Project. Thereafter, it moves on to presenting the results and findings from the MEP Support Project. Finally, it provides recommendations for future energy efficiency engagements within the SMI sector and with MEP organizations, for program administrators in the Northwest as well as across the nation.

BACKGROUND ON MANUFACTURING EXTENSION PARTNERSHIPS

The National Institute of Standards and Technology (NIST), a non-regulatory agency of the US Department of Commerce, unites a program network of Manufacturing Extension Partnerships (MEPs). These MEPs comprise over 1,400 technical experts in the fifty states to provide a variety of services for small to mid-sized US manufacturers that range from innovation strategies to process improvements to green manufacturing. The MEP organizations help small manufacturers to be more competitive so that they can grow and support the region. The primary focus is on reducing waste (e.g. following Lean principles), improving product quality, and enhancing productivity. The MEP effort is a public/private partnership that combines federal funding with investments from other parties, such as universities and state offices, as well as fee-based services to the manufacturers who receive MEP consulting support. In 2008, the MEPs provided in-depth or substantive assistance to about 7,100 manufacturers (5). These small to mid-sized manufacturers generally reported a measureable impact from MEP services on sales, costs, employment or investment.

Each state is supported by one or more MEP organization (there are currently 60 MEP organizations across the US), each of which has a unique combination of local client make-up, services offered, consultant skill sets, organization goals and business models. Table 1 provides an example of some of the variety in characteristics seen across MEP organizations. This great variety in MEP organization make-up makes using a flexible approach the preferred method over a "one size fits all" approach in any MEP engagement, including an energy efficiency engagement. Consequently, a successful engagement with MEP organizations on advancing energy efficiency performance in their clients' facilities must appropriately address key MEP organization priorities, the financial situations of MEP clients, and MEP consultant skills and business approaches.

Table 1. Variety in MEP Organization Characteristics

Characteristic	**Range Across Each Characteristic**
Local Client Make-up	• Large cities with heavy industrial focus • Mix of small and mid-sized manufacturers • Mostly small manufacturers with emphasis on agriculture-related services
Services	• Account management with minimal direct consulting; most of consulting outsourced • All-in-one services, where MEP consultants provide expertise in multiple areas • Specialists, where MEP consultants have areas of expertise in which they focus and collaborate with one another
Business Model	• Funding by state governor's office • Funding through a university extension • Funding as a non-profit organization
Consultant Skill Set	• Business process optimization • Operations management and industrial engineering • Energy-related or other engineering
Organization Goals	• Providing more solutions to existing clients • Expanding clients or channels to include other groups such as utilities or other energy efficiency program administrators

Northwest Manufacturing Extension Partnerships

The Northwest has a rich history of small manufacturing firms growing into billion dollar corporations, including such well-known manufacturers as Boeing, Precision Castparts, Simplot, and Weyerhaeuser. The MEPs in the Northwest provide a critical role in helping transform small manufacturing companies into successful

companies while creating jobs along the way in their respective regions. There are four MEPs in the Northwest. They consist of Idaho TechHelp (TechHelp), Montana Manufacturing Extension Center (MMEC), Oregon Manufacturing Extension Partnership (OMEP), and Impact Washington (Impact). The four Northwest MEPs are experienced process improvement consultants with deep customer relationships. As such, they are ideally suited to learn the necessary elements of energy management and thus impact the Northwest industrial energy efficiency (EE) market positively. In recent years the four Northwest MEPs have collaborated on various projects where their proximity and mix of skills have combined to deliver high-value solutions to industrial clients. A brief summary of the characteristics of the Northwest MEPs follows:

- **Idaho TechHelp (TechHelp)** has a mandate from the US Government and the State of Idaho to help build Idaho's manufacturing sector by providing cutting edge technical assistance, training, and information. Its team of experts provides solutions in areas such as waste reduction using Lean Enterprise, driving sales with product development and rapid prototyping, and improving quality through ISO 9001 and Six Sigma management systems. TechHelp is headquartered at Boise State University and has offices in Pocatello as well as in the Idaho panhandle. TechHelp employs four manufacturing specialists and five new product development specialists.
- **Montana Manufacturing Extension Center (MMEC)** is a statewide manufacturing outreach and assistance center staffed by full-time professionals who have degrees in engineering as well as extensive manufacturing and business experience in a variety of industries. MMEC is located within the College of Engineering at Montana State University-Bozeman. MMEC employs five field engineers across Montana with an additional person focused on energy efficiency opportunities.
- **Oregon Manufacturing Extension Partnership (OMEP)** is a partner with Business Oregon as well as other industry associations and business consortia. It is also strategically affiliated with the Oregon Institute of Technology (OIT). OMEP uses Lean Enterprise as the basis for their manufacturing consulting and training efforts. OMEP employs eleven consultants to serve their clients.
- **Impact Washington (Impact)** is a private non-profit that is not affiliated with a university. It offsets operating costs with state and federal funding. Impact's mission is to strengthen manufacturing in Washington, focusing efforts on increasing profit, developing employee skills, and improving sustainability. Impact has six project managers and utilizes a variety of subcontractors, including the Washington State Department of Ecology, to serve their clients. In the middle of the NEEA MEP Support project it became clear that Impact frequently engages the Washington State Department of Ecology (Ecology) as their implementation partner, so NEEA determined it best to train and support Ecology staff through the project.

THE NEEA MEP SUPPORT PROJECT APPROACH

In the summer of 2010, NEEA launched the MEP Support Project, an 18-month effort that ended in December of 2011. The primary goal of the MEP Support Project was to enhance awareness of energy efficiency in a group of service providers that routinely interact with small and medium-sized manufacturing facilities. Specifically, the MEP Support Project aimed to engage MEP consultants in the Northwest to deliver energy management practices that result in a quantifiable reduction in energy intensity to the clients with which they normally engage. Table 2 summarizes the primary goals of the NEEA MEP Support Project.

Table 2. Northwest MEP Support Project Goals

Goal	Description
Add energy management consulting to the MEPs' Portfolio of Services	Develop and support the four Northwest MEPs, consisting of 37 MEP consultants on staff across the region. NEEA's goal was to train 75% of these consultants to enable them to deploy energy management practices at their clients' facilities.
Encourage SMI facilities to implement energy management practices	Assist the SMI facilities in implementing energy management by tracking and reporting the facilities with which each MEP consultant engages in energy solutions, both the number locations as well as the level of success in implementing energy management practices. NEEA's goal was to have strategic energy engagements documented at 48 SMI facilities.

Goal	Description
Attain cost-effective energy savings	Assist the MEPs in recommending traditional utility program measures as well as operation and maintenance changes that result in energy savings. NEEA's ultimate goal was to attain 4,400,000 kWh in annual energy savings by project completion.
Document energy intensity quantification methodologies	Quantify the impacts of energy engagement using a "top-down" analysis of energy intensity changes as well as a "bottom-up" quantification of a Lean process improvement. NEEA's goal was to develop a documented process for the MEP organizations to use when determining savings from productivity changes or process improvements.
Demonstrate market transformation of SMI energy efficiency market	Demonstrate market transformation success for NEEA stakeholders by training MEP consultants to become agents for energy saving solution. This would be demonstrated by: • Increased penetration of strategic energy management in the Northwest SMI market • Quantifiable energy savings • Successful Case Studies

The NEEA MEP Support Project Team (Team) used a multi-component Direct Influence approach to achieve the goals of the project. This included: stakeholder engagement; training of MEP consultants in identifying energy saving opportunities; and technical support to MEP consultants to help them initiate drive, and track energy saving projects. The components of this approach are discussed below.

Engagement of Northwest MEPs and Stakeholders

Beginning in the summer of 2010, the Team established relationships at all levels within the four Northwest MEP organizations. This allowed for each MEP to articulate its strategic directions and definitions of success and expose executive-level motivations to follow NIST federal initiatives. With this knowledge, the Team structured energy training as a segment of the MEPs' larger initiative(s). For example, TechHelp was already actively participating in the federal Ecology, Energy and Economy (E3) initiative.[2] Consequently, TechHelp used the MEP Support Project to complement its E3 effort. Engagement at the consultant level among all MEPs revealed a robust understanding by MEP consultants of their clients' financial constraints, which pushed the Team to emphasize many low-cost and no-cost energy saving solutions in the project.

The Team also defined stakeholders in each state to ensure appropriate engagement between the MEPs and their clients' local utilities, BPA, state energy offices, and third-party implementers. The Team facilitated these engagements to ensure the project was well understood and all parties were well informed. Additionally, these engagements provided the MEP consultants with a better understanding of available incentives for energy efficiency measures and how to effectively leverage them. Prior to the MEP Support Project, many MEP consultants were either unaware of utility incentives or thought such incentives were a "free for all." During these early engagements the need for a better energy efficiency incentive process understanding among MEP consultants became clear.

The Team also became aware of friction between one MEP organization and one energy efficiency program manager due to misunderstandings such as the need to determine baseline energy use prior to implementing process changes that result in energy savings. As a result, the Team tried to explain the incentive process early and often to the MEP consultants throughout the project. The Team also urged the MEP consultants to contact utility staff for assistance with potential incentives prior to initiating any energy saving project. At the conclusion of the MEP Support Project, the Team helped host joint transition meetings for some of the MEPs and regional utilities to recap project efforts and to ensure implementation of identified energy saving opportunities. The transition meetings also served as a forum for a discussion of future energy engagements where utility energy efficiency programs can leverage MEPs as supporting agents in the SMI energy sector.

[2] The E3 initiative supports businesses through the combined work of five departments and agencies: the US Department of Commerce's NIST MEP program, the US Department of Energy's Save Energy Now initiative and Industrial Assessment Centers, the US Small Business Administration's Small Business Development Centers, the US Environmental Protection Agency and the US Department of Labor's Employment and Training Administration.

Training of MEP Consultants in Identifying Energy Saving Opportunities

One critical component of the MEP Support Project was to train the MEP consultants to identify energy savings opportunities. In the fall of 2010, orientation training for the MEPs kicked off for each state organization separately in a face-to-face, one-and a-half day event. The orientation training covered utility bill structure, utility energy efficiency programs and contractors, typical no-cost and low-cost energy measures, energy audits, energy saving calculations and strategic energy management, as well as information on energy efficiency organizations such as NEEA, BPA and ETO. As part of the orientation training, the Team augmented the classroom training with a demonstration of a properly executed energy walkthrough at a manufacturing customer site selected by each MEP. Due to their hands-on nature, the energy walkthrough exercises were the best received training tools. As a result, the Team offered 8 additional energy walkthroughs after the orientation training to generate momentum for energy engagements at MEP client sites.

Following the orientation training, the Team launched recurring 1-hour webinars on common industrial energy end-uses and typical energy saving measures to augment lessons introduced during the orientation training. Of the 11 topical, hour-long webinars, half were measure-specific and covered topics such as Compressed Air and Motors, while the remaining webinars covered utility and big picture energy concepts. The MEPs specifically asked for webinars on "Dissecting Utility Bills" and "Marketing Energy Savings Projects." The entire list of webinars is as follows:

1. Compressed Air
2. Lighting
3. Motors and Drives
4. HVAC
5. Controls and Sequencing
6. Marketing Energy Savings Projects
7. Energy Tools (data loggers and metering equipment)
8. Advanced Energy Concepts (SEM, Demand Response, etc.)
9. ISO 50001
10. Dissecting Utility Bills
11. Engaging with Utilities

The webinars, along with all other training resources such as training documents and auditing tools and spreadsheets, were recorded and stored on a dedicated website (www.mepenergy.com) for easy access for the MEP consultants. At the conclusion of the MEP Support Project, the Team also copied these resources onto flash drives and mailed them to the MEP consultants for long term access to energy efficiency resources.

Technical Support to MEP Consultants to Initiate and Drive Energy Saving Projects

One goal of the MEP Support Project was to engage MEP consultants in the Northwest to deliver quantifiable energy savings to the clients with which they normally engage. For this project, energy savings were divided into two categories: traditional energy measure savings (e.g., facility lighting upgrade, VSD control) and Lean process energy savings. Each category required distinct approaches.

Traditional Energy Efficiency Measure Savings

The Team took a conservative approach to document energy savings, requiring MEP consultants to use the utilities' traditional energy efficiency measure programs. By following the utility protocols to obtain incentives and perform required calculations, the Team guaranteed the MEPs reliable savings results. For this reason, the Team referred MEP consultants to their local utilities "early and often." The Team provided three primary technical support mechanisms to initiate and drive energy savings:

1. Provide local utility connections
2. Provide engineering support, primarily by phone but also through onsite support
3. Provide marketing support for the MEP organizations to raise industrial client awareness

The Team provided engineering support in multiple ways, including pre-site visit planning, brainstorming, identifying utility incentives, recommending energy efficiency measures, calculating energy savings and payback ratios, and reviewing vendor proposals. To support the MEP consultants, the Team developed and utilized a pre-site visit checklist covering:

- Occupancy and management
- Electric use and cost
- Energy awareness
- Recent and planned energy efficiency measures

Where possible, the Team's engineers also performed on-site energy walkthroughs to evaluate opportunities and outline optimal next steps. Team engineers and MEP consultants documented operational data and end-use equipment details with forms for motors, lighting systems, air compressors, chillers, refrigeration systems and packaged HVAC

units. These forms were valuable tools to support the MEP consultants learning to conduct energy audits and perform ensuing analyses. Furthermore, the engineers used audit tools such as air leak detectors, temperatures guns and data loggers to identify potential energy saving opportunities and define energy baselines. To increase the MEP's familiarity and experience in identifying energy saving opportunities, the Team educated MEP consultants on the use energy walkthrough tools while on-site. MMEC already had a portfolio of data loggers at the project initiation, but there was a significant interest from other MEP consultants in assembling energy tool kits for their MEP organizations. Team engineers assisted OMEP and Ecology in selecting energy walkthrough tools including ultrasonic leak detectors, Infrared (IR) guns and data loggers with sensors. Though Impact and TechHelp showed interest in acquiring energy walkthrough tools, they were able to leverage external partnerships for these resources. Specifically, Impact's clients received compressed air leak audits from Ecology while TechHelp worked with the local utilities to provide data logging services and compressed air leak surveys.

Lean Process Energy Savings

As a part of the MEP Support project, the Team attempted to determine the energy savings associated with implementing process improvements identified by Lean manufacturing (Lean) principles. Specifically, the engineers worked with an OMEP SMI client to estimate energy savings associated with a reduction in start-up time from two hours to one hour for the facility's three manufacturing process lines; this was a Lean process improvement spearheaded by OMEP consultants (3). Figure 1 illustrates the energy use targeted in this reduction as the dark blue area. This simplified diagram assumes that the ramp-up of energy uses associated with process equipment over the full period of the start-up are constant, which in reality they are more step-wise.

A facility with all equipment monitored real-time for energy usage and production throughput would readily determine startup reduction opportunities and resulting energy savings. As most facilities are not optimally monitored, the challenge is to estimate how production occurs compared to how the facility consumes energy. For one SMI client, the Team performed concurrent top-down (facility-wide) and bottom-up (end-use) analyses to avoid omitting potentially important energy consumption inputs and factors.

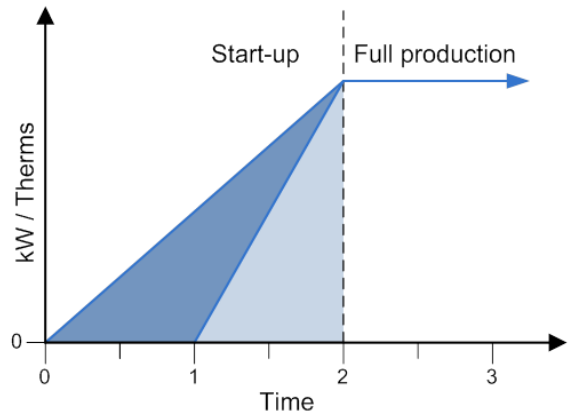

Figure 1. Energy Savings Associated with a Lean Process Improvement

For the top-down analysis, Team engineers used existing monthly utility bills, local weather, and monthly production data to develop two ordinary least squares (OLS) multivariate regression models. The regression analysis determined the model between energy and all significant independent variables, such as production rates, prior to Lean process improvements. Following implementation of Lean improvements, the Team compiled related independent variables, using the regression model above to calculate an adjusted baseline with updated post independent values. Finally, the Team compiled post-improvement utility meter data to compare with the adjusted baseline to estimate energy savings. The bottom-up analysis started with identification of the electricity-consuming equipment on each production line. For each piece of equipment, the Team used amperage measurements and nameplate voltage to estimate power draw, coupled with data logging information to determine operating hours.

Tracking of MEP-initiated Energy Saving Opportunities

MEP-initiated energy saving opportunities are tracked and documented in NEEA's Industrial Tracking System (ITS). In ITS, NEEA categorizes energy savings measures as follows: Identified as an "Opportunity", "Committed" by the customer, installed but "Pending" validation, and "Validated" by a third party. Each energy-saving opportunity is tracked by a measure identifier (e.g., lighting, compressed air). The Team also tracked the level of energy engagement at an industrial site and local utility involvement within ITS.

RESULTS AND LESSONS LEARNED

The NEEA MEP Support Project provided valuable lessons learned, some of which are discussed below.

Total Energy Savings and Popular Energy Saving Measures

The MEP Support Project reported at total of 4,025,566 kWh in energy saving opportunities, or 91% of the goal, at fifteen SMI facilities (4). (The project also reported 30,000 therms in gas savings.) Because the MEP consultants did not start initiating and quantifying energy saving opportunities until 6 months into the 18-month project, the majority of total energy savings (by December 31, 2011) fall in the "Opportunity" category (51%) followed by "Committed" (27%) and "Pending" (22%). Figure 2 illustrates that 27% of total energy savings are associated with efficiency improvements in Lighting, followed by Compressed Air (25%), HVAC (16%) and Refrigeration (15%). The energy savings associated with the Lean process improvement discussed previously (i.e., a reduction in start-up time from two hours to one hour for facility's three manufacturing process lines) resulted in annual energy savings of 277,000 kWh (or 7% of the goal).

A total of 61 energy saving measures were identified in the MEP Support Project. Most energy saving measures involved Compressed Air (19 measure counts), Lighting (14) and Refrigeration (12), as illustrated in Figure 3. The most popular Compressed Air measures consisted of identifying and repairing air leaks, eliminating inappropriate uses of compressed air, and implementing Leak Tag Programs. Most popular Lighting measures included facility-wide lighting upgrade projects and installing occupancy sensors. The types of refrigeration measures identified varied significantly, ranging from closing doors in refrigeration and freezer spaces to VFDs on pumps and fans to sequencing of refrigeration systems.

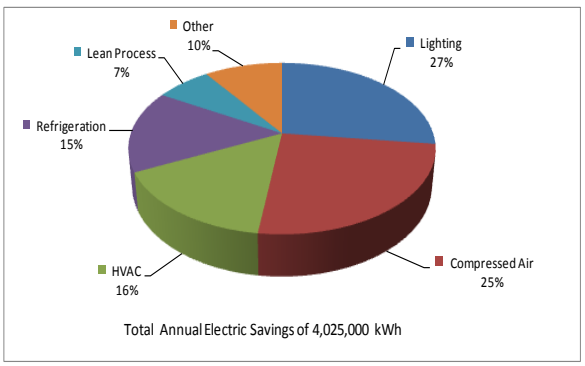

Figure 2. Reported Annual Energy Savings for the MEP Support Project

Interestingly, less than half of all energy saving measures (45%) in the MEP Support Project would qualify for utility incentives. This is due to the fact that more than half of all measures (53%) can be implemented with no capital. For example, fixing air leaks is typically not incentivized by utilities but was a widely popular measure among MEP consultants as it can generate immediate operational cost savings at no cost or low cost to industrial clients. Other examples of low-cost and no-cost non-incentivized measures recommended by MEP consultants to their SMI clients include eliminating inappropriate uses of compressed air, turning off idling equipment, delaying process equipment start-up, and reducing thermostat and occupancy sensor settings. These are all examples of operational changes. (MEP consultants often consider such operational changes as Lean.) Unfortunately, many MEP consultants often discarded energy projects with a return on investment (ROI) greater than 1-2 years. Further, many MEP consultants expected energy savings projects to happen faster than the customers moved. From this, the MEP consultants preferred to conduct short ROI projects to demonstrate immediate cost savings. Focusing on easy-win short ROI energy saving projects, such as fixing compressed air leaks, was most effective. In a few instances, MEP consultants also decided to forego incentives as they felt the utility incentive application process was too time-consuming for the amount of incentive available.

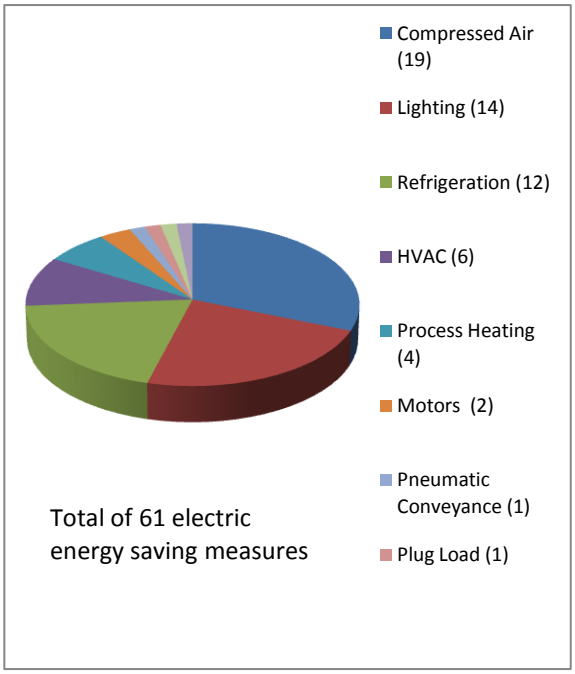

Figure 3. Energy Saving Measures Identified by MEP Consultants

Table 3. Summary of Key Energy Saving Findings

Utility incentives relatively uncommon	Less than half of measures qualified for utility incentives
	Incentive application process was sometimes too time-consuming and thus foregone by some MEP consultants
No-cost/Low-cost operational and Lean process changes most popular measures	MEP consultants discarded projects with ROI >1-2 years
	MEP consultants preferred operational changes over equipment upgrades. Popular measures include: • Fixing air leaks • Eliminating inappropriate uses of compressed air • Turning off idling equipment • Delaying process equipment start-up • Reducing thermostat settings • Reducing occupancy sensor settings

Transition of MEP Consultants as Energy Agents

Prior to this project, only two MEPs had notable utility relations, namely OMEP with ETO and MMEC with three Montana utilities. As a result of the MEP Support Project, all four MEPs had developed additional utility relationships in their regions as of project completion. The Team fostered relationships between MEPs and utilities by inviting the utilities to MEP training events and customer energy walkthroughs as well as suggesting utility technical resources to MEPs. Finally, the Team hosted joint transition meetings to recap project efforts and discuss future energy engagements. At the conclusion of this project, three of the four Northwest MEP organizations had enhanced their company websites to include energy offerings and case studies, indicating energy becoming an increasingly important part of the MEP consultant's work. For example, TechHelp is conducting a series of RISE3 (RISE=Resources for Idaho to Save Energy) Road Show Events in spring of 2012. At these events, attendees from the local manufacturing communities will learn about programs that can help fund energy efficiency projects. RISE3 leverages the resources and expertise of the Industrial Assessment Center in Boise and utility companies throughout Idaho.

Influencer Role is Complicated

The Team faced many challenges unique to the influencer role in terms of driving results from influence rather than the direct impact approach used in previous NEEA Industrial efforts. Perhaps the most significant challenge was relinquishing industrial site access and control. Rather than directly soliciting clients for energy engagements or site information, the Team relied on the MEP consultants, who were new to energy efficiency and also juggling multiple agenda. The initial project anticipated the MEP consultants would proactively engage the Team to support energy saving opportunities. In reality, the project did not gain traction until the Team initiated monthly consultant outreach calls and performed on-site audits. Additionally, MEP consultants are influenced by funding considerations and other projects. Indeed, some MEP consultants referred to the MEP Support Project as an "unfunded mandate" with no reimbursement for time spent on identifying energy saving opportunities. As a result, the Team adjusted many timelines and expectations, discovering that momentum is difficult to maintain.

MEP Consultants Need to Better Involve Utilities, and Vice Versa

Though utilities have staff and resources available for energy audits, data logging and savings/incentives calculations, in most cases MEP consultants did not leverage this expertise. Having one orientation gathering and then a final transition meeting did not provide enough touch points for the utilities and MEP consultants. Additionally, many MEP consultants felt uncompensated for the benefits of energy savings from Lean process improvements. Clearer articulation of utility funding requirements for Lean process energy projects is needed to get across the importance of establishing energy baselines prior to calculating energy savings and applying for incentives. Quarterly meetings between MEP consultants and local utilities would have been beneficial.

Advancing Energy Value Stream Mapping

Lean manufacturing principles are different than mass production principles in that they focus on increased flexibility and quick response to the changing customer demand. This, in turn, can lead to high quality at the lowest cost in the shortest amount of time. For most MEP efforts, a core Lean tool is value stream mapping (VSM) in which value streams are quantified to target areas for improvement. There are seven "deadly" wastes identified as part of Lean manufacturing:

1. Transportation – Moving products unnecessarily
2. Inventory – All components, work-in-process, and finished product not processed
3. Motion – Equipment, product, or people or moving more than is required to perform the necessary processing
4. Waiting – Also called work-in-progress, product not in transport or being process, waiting for the next production step
5. Over-processing – More work done to a product than is necessary
6. Overproduction – Production ahead of demand; this is considered the worst type of waste because it hides and/or causes the other wastes
7. Defects – Cause additional effort and cost to fix the defects

Reducing energy use in the manufacturing process is not an explicit goal of Lean manufacturing. However, reductions in energy use are often a resulting side-effect of the overall efficiency improvements resulting from Lean process changes. Additionally, due to energy's lower cost relative to other operational costs, MEP consultants typically do not measure it in great detail. However, the Lean process changes identified within VSM can produce significant energy savings. Therefore, it would be beneficial to prove the viability of Energy VSM to identify and drive energy savings through the SMI segment. For example, OMEP is currently exploring the value of Energy VSM with a few manufacturing clients. To increase the reliability of energy savings associated with Lean processes identified through the Energy VSM process, it would be beneficial for MEP organizations to collaborate with utility program managers. Ultimately, such collaborations could result in utilities providing incentives for Lean process improvements.

CONCLUSIONS

The NEEA MEP Support project generated numerous interesting results and lessons learned. The key take-away points from the NEEA MEP Support Project include:

- **MEP Consultants are Good Energy Agents for the SMI Market:** MEP consultants are good energy agents for utilities to utilize when targeting the SMI market for energy savings. In the NEEA MEP support Project, consultants from the four Northwest MEPs identified in excess of 4 million kWh in annual energy savings at small and medium-sized manufacturing facilities.
- **Influencer Role is Complicated:** Relinquishing industrial site access and control to the MEP consultants rather than directly soliciting industrial clients for energy engagements is highly complicated, especially when MEP consultants are not fully dedicated to energy. It can be difficult to evaluate effectiveness, including determining savings from an MEP consultant's client, when that MEP consultant is not a compensated part of a utility or other program. Any program that seeks to leverage the MEPs should spend significant time studying the potential role possibilities.
- **MEP Consultants Want to be Compensated for Initiating Energy Saving Projects:** MEP consultants want to be reimbursed for their time spent on identifying energy saving opportunities. They feel that their SMI clients do not see the value in the MEPs including energy saving activity as part of their services, so any energy-related work the MEP consultants provide is for free. Furthermore, when any resulting energy savings are incentivized by a utility, some MEP consultants feel that the utility benefited when the MEP did not. Additionally, MEP consultants believe utilities should provide incentives for energy savings derived from Lean process improvements.
- **MEP Consultants Prefer Operational/Lean Process Changes over Equipment Upgrades:** Because MEP consultants specialize in Lean practices, they prefer to recommend operational changes, such as fixing air leaks and shutting off idling equipment, rather than capital equipment upgrade projects. Furthermore, in today's business environment, SMI facilities do not have easy access to capital for equipment upgrades which makes it even harder to initiate energy saving projects that involve replacement of inefficient equipment with energy-efficient equipment. Also, to meet clients' demand for projects with short ROI, MEP consultants are typically unwilling to recommend energy saving projects with ROI greater than 1-2 years. As a result, equipment upgrade projects are often not initiated.
- **MEPs and Utilities Need to Better Leverage Each Other's Expertise:** Though utilities have staff and resources available for energy audits, data logging and savings/incentives calculations, in most cases MEP consultants did not leverage this expertise. Similarly, most utilities are currently not advancing energy saving opportunities associated with Lean process changes. Therefore, it is recommended that MEPs and utilities collaborate on Lean energy saving projects. For example, it would be

beneficial for the two parties to jointly host Energy VSM exercises at SMI facilities.

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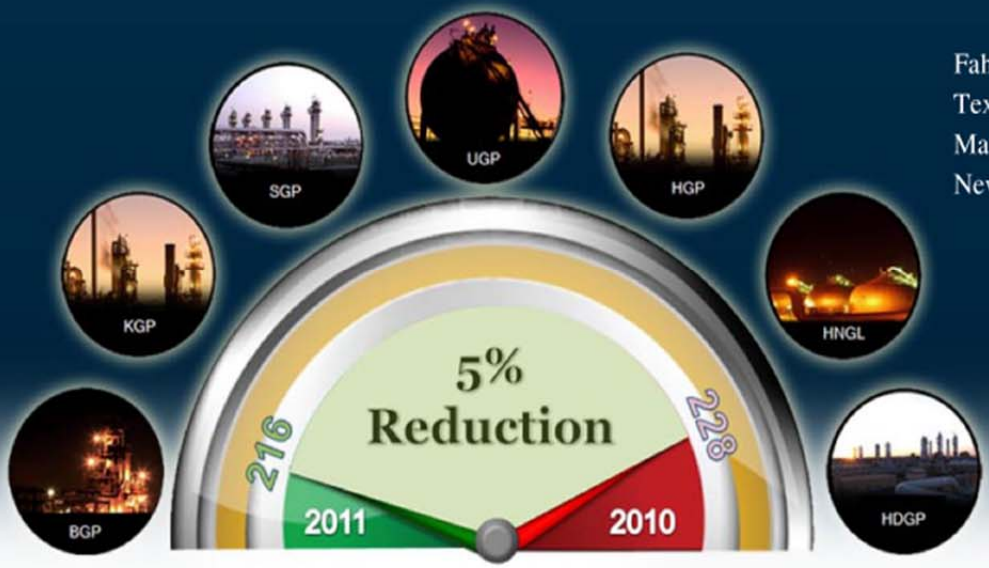
ارامكو السعودية
Saudi Aramco

GO Energy Efficiency Program

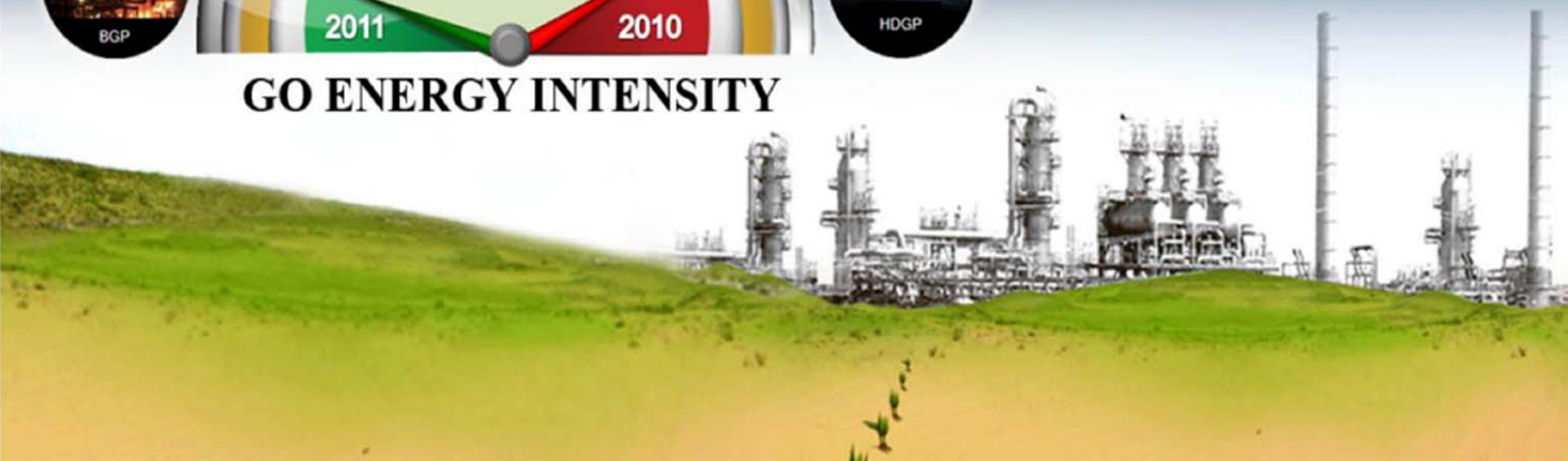
Translating Strategies into Realities,
A superior energy efficiency program for industrial facilities

Fahad S. Al-Dossary
Texas A&M industrial Energy Technology Program

May 29 – June 1, 2012
New Orleans, USA



GO ENERGY INTENSITY



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- Saad Al-Shahrani Manager ShGP
- Khalid Al-Shammary Engineering Superintendent, UGP

Saudi Aramco Gas Operations Energy Efficiency Program

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ABSTRACT

Saudi Aramco Gas Operations (GO) created energy efficiency strategies for its 5-year business plan (2011-2015), supported by a unique energy efficiency program, to reduce GO energy intensity by 26% by 2015. The program generated an energy savings of $ 8.8 MM, equivalent to 5% energy intensity reduction in 2011 as compared to 2010 level. The program works through a structured process, pre-set energy targets, installations of online energy management tools, and implementation of key high impact energy efficiency initiatives and completion of energy conservation projects.

The long-term fruit of the program was recognized as a best practice to be adapted by most of Saudi Aramco facilities. The generation of innovative energy saving ideas under implementation resulted in potential energy savings of $23 MM.

This paper confirms what many others in the industry have found, the opportunity is significant. The author illustrates GO organization crafted a structured energy efficiency program and innovative approaches to unlock the full potential of higher standards of energy efficiency performance.

Gas Operation energy efficiency program will ideally translates energy intensity strategies into realities and transforms the missed opportunities into practical tactics for capturing the millions of dollars of savings potential that exist across GO facilities.

BACKGROUND

GO consists of seven gas processing plants, which accounts for 28% of Saudi Aramco energy use. It is a key organization to Saudi Aramco and the Kingdom of Saudi Arabia, both from the standpoint of the amount of energy generated and the magnitude of the energy consumed. GO supplies the kingdom's domestic energy supply of Sales Gas and Natural Gas Liquids for utilities and the petrochemical industry.

The success of GO energy performance depends on controlling and measuring the progress and performance of the energy efficiency. Saudi Aramco created a mechanism to measure the energy performance of all the company operating facilities using the energy intensity index.

Energy intensity is the standard index used in several industries and Saud Aramco's Energy Management Steering Committee (EMSC) has adapted it as its standard energy KPI to monitor the operating facilities energy efficiency.

The EMSC was formed in 2000 under the chairmanship of Saudi Aramco Chief Engineer. The EMSC main charter is to ensure that the Energy Management Programs are implemented in accordance with the corporate energy conservation policy with long range ambitious cost and energy intensity reduction.

Energy intensity is defined as the energy required to generate a unit of product. The Energy intensity can be defined as followed:

$$EII = \frac{Energy\ Consumption\ (MMBTU)}{Plant\ Feed\ (MBOE)}$$

The intensity is calculated by the energy consumption expressed in 1000 BTU over the total production in barrels of oil equivalent. Energy includes any Btu used to convert the original feed into the final product.

The Energy intensity is used to represent the energy performance of the gas processing facilities and it is not used to compare different organizations and different plants because each plant is unique in its process and design. Some of the old Gas Plants have more energy intensive processes because of the sour feed gas mix rich with associated sour gas containing concentrated acid gas and hydrocarbons, age and the capacity utilization.

The utilization of GO facilities is impacted by the domestic market seasonality, which has a greater effect on the energy intensity to be undesirably trending up as shown in Figure 1. The BAU projections for 2011-2015 business plan forecast a dramatic 30% increase in GO energy intensity.

In this environment, sustaining momentum to improve energy efficiency will require management top down support to sponsor organizational energy intensity strategies with the implementation of a comprehensive energy efficiency program.

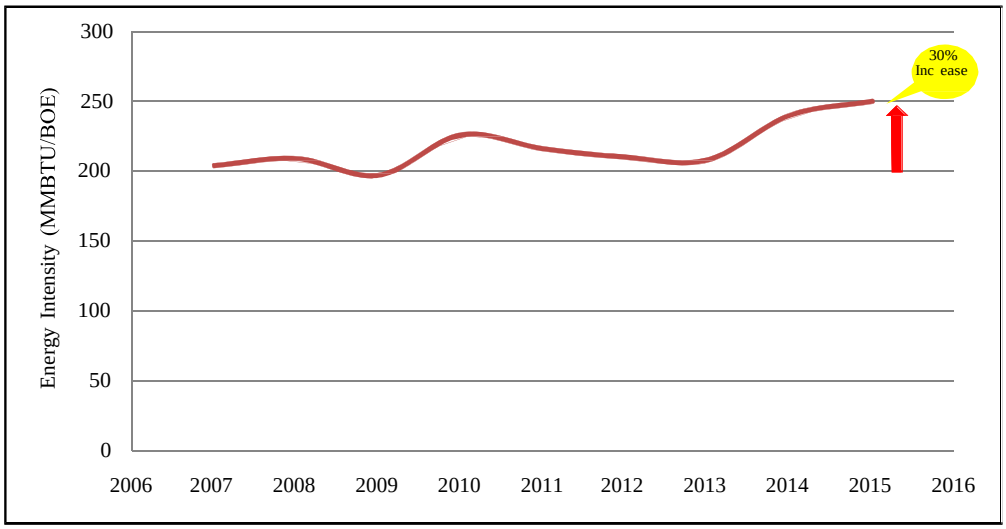


Figure 1: GO Energy Intensity Outlook

ENERGY INTENSITY STRATEGY

The energy intensity strategy is an operational document that sets out how GO will achieve a 26% reduction in the energy intensity by 2015 as shown in Figure 2. The desired target reduction is through a 10% by internal improvements and 16% by energy projects over a 5 year business plan.

The strategy is cascaded for each of the seven gas processing facilities in GO; UGP, SGP, BGP, HGP, HNGL, HdGP and KGP defining the high impact strategic initiatives and opportunities to unleash higher levels of energy efficiency.

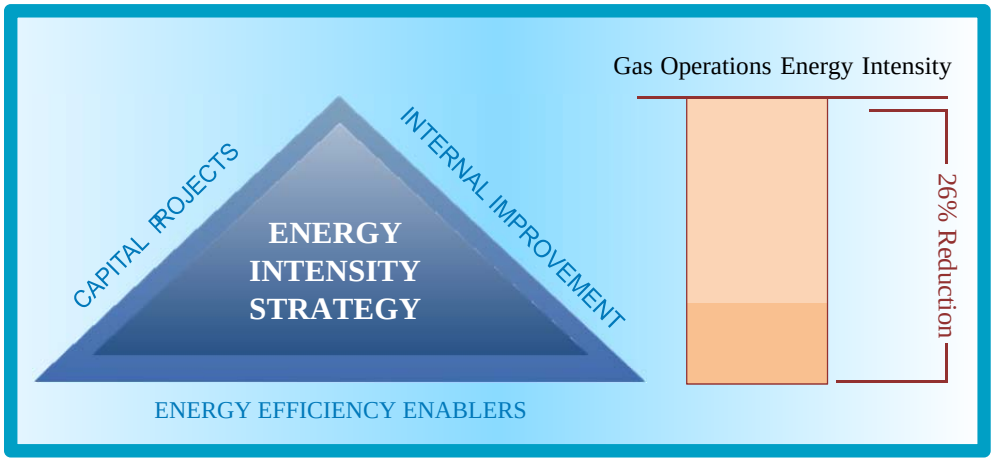


Figure 2: GO Energy Intensity Strategy

A. Energy Efficiency Enablers

The energy efficiency enablers are set of programs and tools to measure, optimize, and proactively manage GO energy intensity strategy. The enablers are supported by three key initiatives as seen in Table 1. The initiatives are translated into action plan and are tracked by GO Energy Focused Team.

Energy Efficiency Enablers
Energy Efficiency Culture
Online Energy Management Model
Assign Accountability/Responsibilities

Table 1: Energy Efficiency Enablers

B. Internal Improvements:

The internal improvement includes the capture of the low hanging fruits, best practices and the high impact energy efficiency initiative shown in Table 2. The internal improvement is the outcome of implementing the energy assessment studies and translating the data from the energy management tools into value.

Internal Improvements
Energy Assessment Studies
CHP Model Optimization
MGS Pressure Optimization
Establish Effective Load Management Program

Table 2: Energy Efficiency Internal Improvement

C. Energy Efficiency Projects

This element includes a review, validation and screening of GO energy projects based on the most recent and previous energy assessment studies recommendation as shown in Table 3.

The revised list contained 24 energy projects for the gas processing facilities to prepare a sound economic business case to be considered for capital funding.

Energy Efficiency Projects
Prioritize Energy Saving Projects
Prepare Business Cases for Energy Saving Projects
Implement & Optimize Cogeneration

Table 3: Energy Efficiency Projects

This strategy is in effect with GO organizational framework that will enable energy efficiency to develop and integrate with the other business structural programs for each individual gas processing facility. To translate the strategy into a reality, a holistic cultural approach and energy efficiency program was created.

GO ENERGY EFFICIENCY PROGRAM

Energy efficiency is all about a comprehensive energy management program. It had been widely understood over decades by management — in the industry and on the frontline — that energy efficiency is achieved by conducting and implementing energy audit recommendations. A similar concept still exists in the industry that says energy efficiency is achieved by capturing one or two easy picking energy saving ideas, and filling out the annual energy performance report.

GO created a structured energy efficiency program that converts data, energy management tools and knowledge to value and revenue. The program is intellectually framed to model GO processing facilities business through human capital commitment, capturing energy opportunities, tracking the progress, promoting and rewarding energy innovation.

The program is aligned with Energy Star guidelines to promote energy management. GO Energy Efficiency program consists of six sequential elements, forming the acronym "M.E.A.S.P.I."

1. **M**aking Commitment
2. **E**nergy Efficiency Culture
3. **A**ssessing Performance
4. **S**etting Goals/Action Plan
5. **P**erformance Tracking Tools
6. **I**nternal Improvements

ELEMENT#1: MAKING COMMITMENT

Gas Operations has a multimillion dollar annual energy bill. It made sense to allocate dedicated staff and resources to a full time role to excel in managing energy use. No matter the size or the type of an operating facility, the founding element of successful energy management is the commitment to achieve continuous improvement.

1.1 Energy Engineer Appointment

This element covers creating a focused energy team by the assignment of a full time energy engineer with clear responsibilities and goals to promote energy management. The energy engineer was assigned for the seven gas processing facilities. The energy engineer is in charge of managing and tracking the plant energy performance to capture energy opportunities in day-to-day operations. This engineer is supported by a part-time multidisciplinary internal energy focused team.

The Energy Engineer key duties often include:

- Monitor the plant operations and optimize energy consumption daily.
- Evaluate the plant processing equipment efficiency and come up with proposals to improve their energy performance.
- Perform energy assessment studies.
- Benchmark the plant performance to similar facilities to identify energy saving best practices.
- Develop business case and conceptual engineering studies for energy conservation projects.
- Conduct evaluations in partnership with P&CSD to implement new technologies for energy conservation.
- Coordinate and direct the overall energy efficiency program.
- Act as the point of contact to the plant management on energy initiatives and the energy conservation program progress.
- Lead the energy focus team.

1.2 Energy Focus Team Framework

GO developed an in-house framework to capture and plan for energy saving opportunities. The program provides the infrastructure for setting performance goals and integrating energy management into an organization's culture and operations. The focus team is assigned on a part time to support the function of the energy engineer. The framework of the focus team is a six steps process as shown in Figure 3.

Figure 3: Internal Energy Focus Team Framework

Step 1: <u>Daily Energy Monitoring</u>

This is a daily performance review of the plant at the shift superintendent's office in the central control room. The plant mode of operation and the key process performance indicators are reviewed to highlight energy saving opportunities in the current operation utilizing energy conservation tools such as the Energy Monitoring Performance System (EMPS) and the Combined Heat and Power model (CHP).

Step 2: <u>Capturing Opportunities</u>

The energy saving opportunities are captured by:

- A daily meeting with the shift superintendent early morning to review the plant energy performance to implement the captured potential energy opportunities.
- An action is taken following this meeting to adjust the plant operations to reduce the energy consumption as required.
- Similar meetings and discussions are also carried out with the energy intensive operating area Foremen to raise the aware ness.
- An agreement is reached where the best mode of operations get selected to be the preferred one for that week.

Step 3: <u>Weekly Energy Efficiency Report</u>

The team concludes the weekly activities to review the plant energy performance and the impact on the energy intensity targets. A weekly energy performance report issued with the captured and missed opportunities during that week. The weekly report also highlights potential opportunities for next week based on the plant's forecasted mode of operation and the missed opportunities for the previous week.

Step 4: <u>Missed/Forecasted Opportunities</u>

This is a continuous process to evaluate the performance of each week energy efficiency through the missed and forecasted opportunities.

Step 5: **Implementation of the Weekly Report Recommendation**

This is the role of the energy engineer and the internal energy focus team to influence the cultural change through step#1 with continuous awareness. Tactical approaches are used by the team to correlate energy saving to the thinking and interest of the frontline in the field.

Step 6: Report Challenges

The focus team gathers and analyzes the challenges in capturing the energy efficiency opportunities highlighted in the weekly report. The team tracks, investigates these challenges, and be presented monthly to the department Energy Management Committee.

ELEMENT#1: ENERGY EFFICIENCY CULTURE

Making the business case for controlling energy consumption is perhaps becoming easier but the implementation of an energy efficiency strategy and programs would require a knowledge based energy efficiency culture and management support top down approach.

Energy efficiency is no longer just about improving technologies or tweaking industrial processes. It is about doing these things and educating and working with the human assets who operate the machines and energy intensive processes. Employees' engagement and motivation is literally a large untapped resource for sustaining GO energy efficiency culture.

The culture did not happen overnight, it took 2 years to translate the energy intensity strategy to realties. Communication strategies and persuasive leadership are the key to success through frequent update to management and working with all levels of employees.

GO proposes the followings as best practices to create knowledge based energy efficiency culture for any industrial facility:

- Creating energy intensity focus team to establish long-term strategies and initiatives to reduce GO energy intensity. The team will work with management and the frontline at each plant to implement energy intensity strategy.
- Assigning a department manager to chair the energy focused team with the subject matter experts and the frontline in the field.
- Engaging the frontline including Process Engineering Supervisors and energy engineers to be part of the energy focus team.
- Getting the buy in of the senior and middle management to support GO Energy Efficiency program. This should come through continuous and close contact with management to present the long-term fruit of achieving the strategy targets and goals.
- Increasing the awareness by the Energy Intensity focus team to visit and share the strategy objectives with each single facility.
- Establishing internal energy focus team for every facility to translate the energy intensity strategy into actions. This team not only yields practical solutions to the complex problems of adjusting process equipment but will build trust with operators and make it easy to sell the energy efficiency program.
- Assigning a full time energy engineer to lead the part time internal energy focused team to run the departmental energy efficiency program.
- Conducting awareness sessions for operators and engineers to unlock their talent and knowledge.
- Continuous training and certifications of the energy engineers. This development will empower and value the energy engineers to drive their own facility energy efficiency program.
- Tapping into communication strategies such as brainstorming sessions, banners, outreach programs, networking and participating/attending conferences.
- Employees engagement through conducting annual energy context to recognize and implement their own energy saving ideas.

ELEMENT#3: ASSESSING PERFORMANCE

This element is to establish an achievable target for the reduction of GO energy intensity for 2011 based on the 2010 actual performance. The 2010 energy intensity level was established as the baseline from which progress was measured.

The energy intensity in 2010 averaged 224 MBTU/BOE. To achieve GO energy intensity target of 2% reduction from the baseline, the energy intensity for 2011 should be around 215 MBTU/BOE. Thus, our "Operating As Usual" forecasted energy intensity for 2011 is 225 MBTU/BOE. Therefore, the required reduction in the intensity to achieve 2012 target would be 5%.

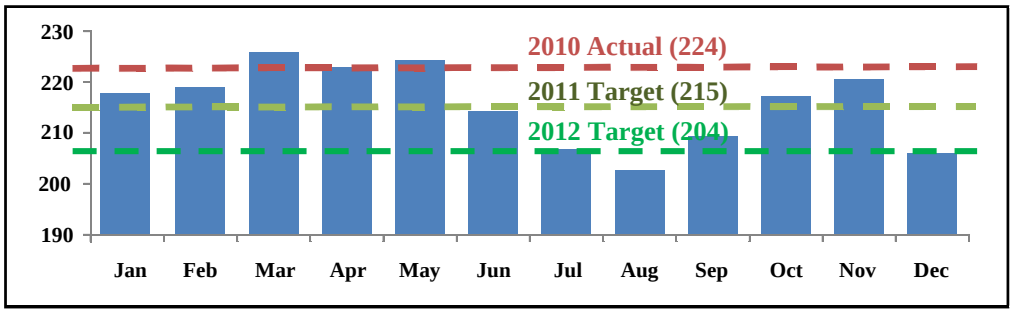


Figure 4: GO Energy Intensity Target Setting

ELEMENT#4: SETTING GOAL AND ACTION PLAN

This element is to analyze and evaluate the performance of each GO facility to identify the previous year's lost opportunities to be captured for the current operating year. This exercise should be conducted at the end of every operating year by the gas processing facility internal energy focus team.

Potential improvements are evaluated through two essential performance measures: the energy efficiency lost opportunities, and the Detailed Energy Assessment Study. One of the gas processing facilities is an example for the level and magnitude of the captured energy opportunities, as demonstrated in the following case study:

3.1 2010 Lost Opportunities Assessment: The plant performance was reviewed by identifying the lost energy opportunities to establish a benchmark for 2011 energy performance. The load management and efficiency of power and fuel intensive processing equipment were analyzed to quantify the missed energy opportunities. It is estimated that a total energy saving opportunities of $ 4.8 MM was missed in 2010 for one gas processing facility, equivalent to 4% of 2010 energy intensity. Some of the missed high impact opportunities were translated into a captured energy savings during 2011.

Missed Opportunity	Energy Saving ($)
Motor vs. Turbine Optimization of G-103A/B (Utility)	9 M
Boiler Load Management (Utility)	186.6 M
Minimizing the Utilization of Standby Regeneration Gas (LRU)	2333 M
Minimization of Boiler Steam Reserve (Utility)	288M
Minimization of Unnecessary Excess Steam Condensing (Utility)	890M
Utilization of the New HPDGA Sweet Gas Letdown Station (Gas Treat)	306M
Total Savings	4.843 MM

Table 5: Missed Opportunities Analysis

3.2 Detailed Energy Assessment Study:

Energy assessment is a key element in any energy management program. The plant age, operating conditions, and feed gas composition determine the frequency of conducting energy assessment studies. The assessment was conducted for more than one gas processing facility and high impact energy saving opportunities were identified.

The assessment demonstrated a potential reduction of the facilities energy intensity of around 20% by implementing the energy efficiency projects and 3-4% through internal improvements.

ELEMENET#5: PERFORMANCE TRACKING TOOLS

The backbone of a successful Energy Efficiency Program is a robust Energy Management System. GO adopted the Energy Performance Monitoring System (EPMS), to analyze and convert energy data into useful information that supports timely and accurate decisions, to improve the plant's energy performance. The function of the EPMS is to ensure that the GO Energy Efficiency Program is on the right track toward the established goals.

Most of GO plants were motivated to implement the EPMS since it requires substantially low investment, as opposed to high capital investment projects, and generates moderate energy saving. Based on GO energy performance data, the energy savings that have been realized at some of GO facilities by implementing the EPMS are about 3 to 5% with a return of investment of less than one year.

Online Energy Performance Monitoring System:

EPMS is a comprehensive online process model of the plants' major consumers and producers of energy using a Data Validation and Reconciliation (DVR) software technology uses a thermodynamic based process model and statistical techniques to validate and reconcile measurements using first principles equations, specifically mass and heat balance equations.

The main objective of deploying EPMS is to help GO facilities to achieve the target set by GO Energy Intensity Strategy to reduce the plant's energy intensity index (EII) by 10% by 2015 (2% annual reduction in EII) through internal improvements.

The EPMS model as in Table 5 includes the fuel network, power network, steam network, and the major energy consumers in the process units. EPMS calculates energy indices based on validated data such as the plant and process unit energy intensity indices. Furthermore, it provides perfor mance monitoring of key performance parameters for major rotating and fired equipment, e.g., efficiency, heat duty, and fouling for each section in steam boilers.

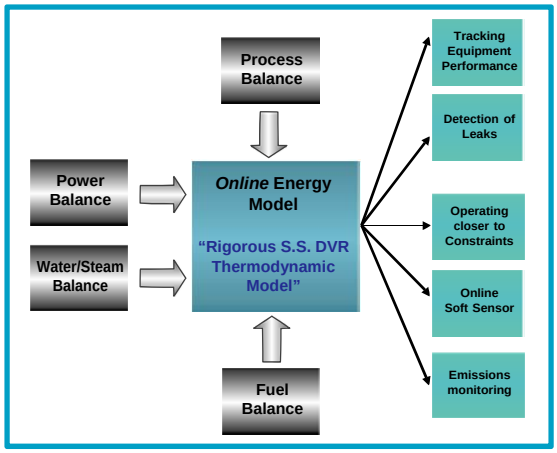


Table 6: Online Energy Performance Monitoring

The EPMS has been running at Shedgum Gas Plant since January 2011 and a recent post implementation audit concluded deployment of the EPMS across all GO facilities. The benefits were broadly classified into the three categories listed below, where an example for each category is described:

4.1 Instrument Condition Based Maintenance:

Based on 6 months data, the EPMS identified that there was a bias in the instrument measuring the total fuel gas to the utility plant (96FY101) as shown in figure 5. After correcting the fuel gas meter reading, this error was eliminated where the validated values matched the measured values. Thus, since this measurement appears in the calculation of the Energy Intensity Index (EII) of the plant, the overstatement of the fuel gas consumption by the utility plant contributed to the overstatement of the plant's overall EII value. Based on the average of 5 months data — from January 2011 to April 2011 — the EII based on measured data and validated data was 221 and 201 respectively. This difference translated into a 10 % drop in the EII based on the validated data.

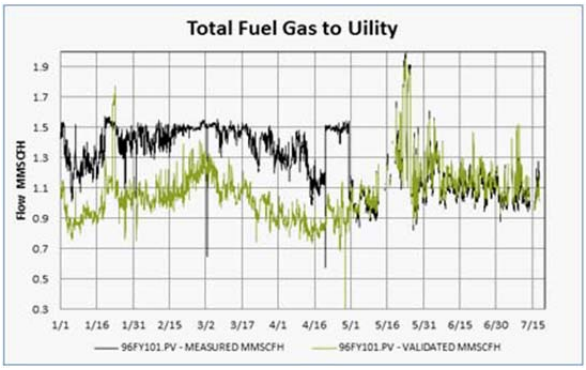


Figure 5: Utility Fuel Gas Measurement Bias

4.2 Furnaces Energy Efficiency Improvement:

Another benefit highlighted by EPMS is the identification and quantification of the opportunity to improve the sulfur recovery units acid preheater performance. After validating the process parameters around these energy-intense sets of equipment, the EPMS readily calculated the efficiency of each furnace highlighting the potential opportunity for energy saving, despite the absence of a combustion air measurement.

A comprehensive analysis of the efficiencies of all SRU preheaters has been conducted for the period between April and July 2011. The following are the findings and results of the analysis:

- As shown in the chart below (figure 5), Preheaters in SRU 1-4 are operated at an excess air level much higher than the recommended limit of 15% (or 3% oxygen level at the furnace stack).

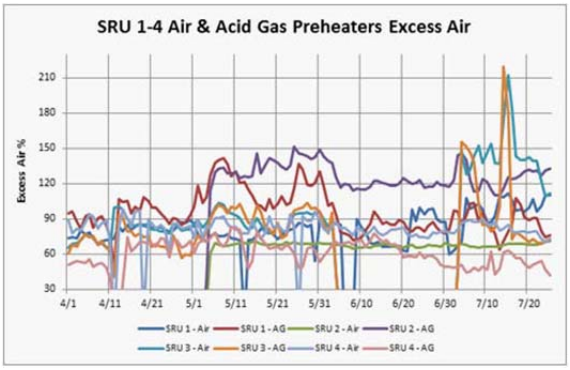


Figure 5: Utility Fuel Gas Measurement Bias

- The excessive air flow has adversely impacted the thermal efficiency of the preheaters. As can be seen from the graph below (figure 10), the average efficiency of all SRU preheaters ranged between 20 to 60%, compared to an achievable efficiency of 70% with a controlled excess of air at 15%. As highlighted by the EPMS, the total energy saving opportunity in SRU preheaters is equivalent to $ 2 MM/year.

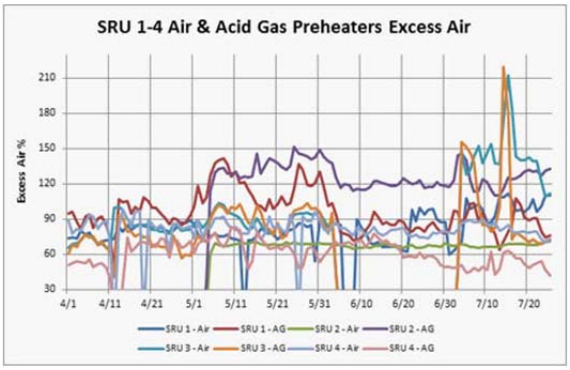


Figure 6: Preheaters Excess Air Levels

The quantified energy-saving opportunity by the EPMS provides an essential basis in the economic evaluation and justification of capital investments, such as an air control retrofit to improve the preheaters' efficiency

ELEMENT#6: INTERNAL IMPROVEMENTS

Energy efficiency is dependent on capturing internal improvements through variations and optimizations of operational practices. This element will illustrate examples of GO energy saving ideas that were realized during the implementation of the GO Energy Efficiency program in 2011.

The internal improvements generated an energy savings of $ 8.8 MM, equivalent to 5% reduction in the energy intensity by the end of 2011, as compared to 2010 level as shown in Figure 8. The internal improvement is the end product and the measurement of GO Energy Efficiency Program performance. The success factors were the commitment, the roll out of the strategy, the top down management support approach, and the focus and implementation of the GO Energy Efficiency program.

Energy Intensity Data	201	2011
Total Product (MBDoe)	295	3063
Energy Consumption (MMBTU/h)	2137	21091
Energy Intensity (MBTU/BOE)	173.	165
% Reduction In Energy Intensity		-4.90%

Table 8: GO Energy Efficiency Performance

Case Study#1: Operational Philosophy

The operational philosophy of standby equipment such as motors, pumps, and boilers should be controlled by energy efficient practices. The selection of equipment to put online is driven by equipment energy efficiency.

As shown in Figure 9, the least efficient fuel gas compressors K-001B used
to be in operation while the higher efficiency K-001A was on standby. A switching between the two compressors generated a power consumption saving of 3 MWH with a potential annual energy saving of $ 2 MM.

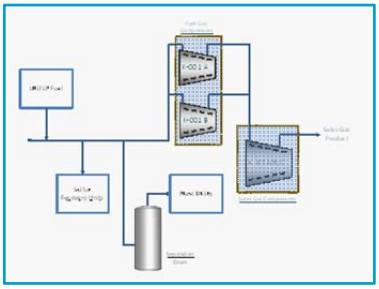


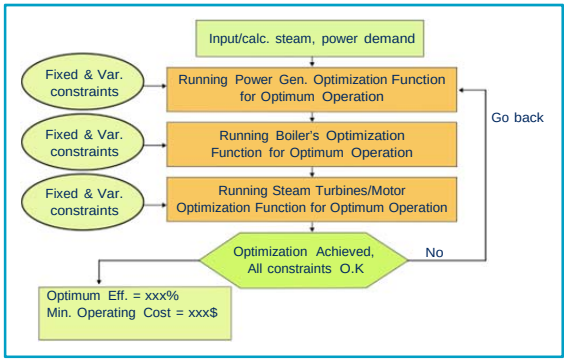
Figure 9: Fuel Gas Compressors Operational Philosophy

Case Study#2: Turbine versus Motors Operation Strategy

The CHP optimization model is an excellent tool used to demonstrate the impact of the facility feed mix changes and steam requirements on the utilities mode of operation strategy. The (CHP) optimization model helps understanding the interactions between the various utilities' components. The model is composed of boilers, gas turbine generation units along with HRSGs, steam network, steam users (process steam requirements), steam turbines and motors, reducing stations, etc. Optimizing such a complex system requires a sophisticated model.

The optimization system requires two functions on top on each other; one is for doing the optimum selection of the units to be used; and the other one is for doing the economic dispatch to satisfy the required demands (power and steam). So, there are several objective functions used in the optimization system, and we may call the optimization system as a multi-objective optimization system with one final objective (minimum operating cost)

There are three levels of optimization as shown in Figure 10 (Cogeneration level, boilers level and steam turbines drivers vs. Motors level).



Eng Efficiency Based Optimization Model

Figure 10: CHB Optimization Levels

The Combined Heat and Power (CHP) optimization model was developed by Saudi Aramco Process and Control System Department for GO facilities. A good example of the economical benefits of utilizing the CHB in a gas processing facility is the selection of running steam turbine drivers instead of motors that are driving the same operational service. This optimization depends on the plant mode of operations and the feed gas compositions, which drives the steam demand and the motor versus turbine selection (Figure 11). This simple no cost optimization had granted an energy saving opportunity of $ 1.2 MM/year for one gas processing facility.

The program is expected to reduce GO energy intensity down to 26% by 2015, with the implementation of the high impact innovative energy saving ideas and the commissioning of the additional cogeneration facilities.

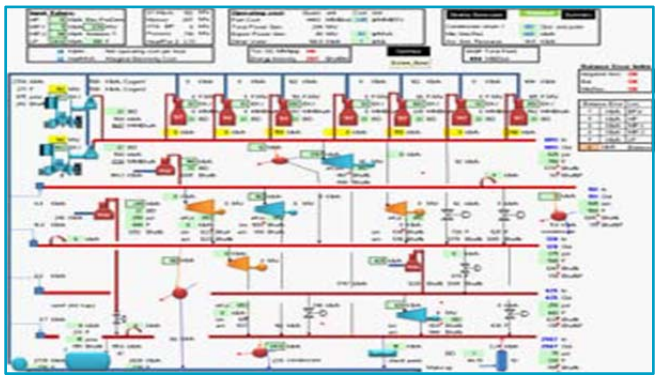


Figure 10: CHP Case Run

CONCLUSION

Energy efficiency offers a vast, low cost energy resources for GO but only if a structured comprehensive energy efficiency program is implemented. The success of the GO energy efficiency program required careful planning of intensity targets, initiatives, and the continuous support of the GO Vice President and Management.

A significant knowledge based energy efficiency cultural paradigm shift — at multiple levels — took place throughout the implementation of the GO Energy Efficiency Program across seven gas processing facilities. Once the program was executed at this scale of facilities with variant energy intensive processes, an energy saving of $ 8.8 MM was harvested and is expected to double once all small scale energy efficiency projects are completed.

INDEX

GO = Gas Operations
UGP = Uthamniyah Gas Plant
SGP = Shedghum Gas Plant
BGP = Berri Gas Plant
KGP = Khurasaniyah Gas Plant
HGP = Hawiyah Gas Plant
HNGL = Hawiyah Natural Gas Plant
HDGP = Haradh Gas Plant
P&CSD = Process and Control Service Department
EII = Energy Intensity Index
MMBTU = 1,000,000 BTU
MBOE = 1,000 of barrel of Oil equivalent
M = 1000
MM = 1,000,000
EPMS = Energy Performance Monitoring System
CHP = Combined Head and Power
MWH = Mega Watt per Hour
K-001 A/B = Fuel Gas Compressors
BAU= Business As Usual

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Power Reliability at BASF Corporation

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ABSTRACT:
Quality is defined not as what the supplier puts into the product but what the customer gets out and is willing to pay for. Power quality problems present themselves in a variety of fashions, many of which cause process interruptions. Process interruptions lead to supply interruptions to the customer. An oft-interrupted supply can be viewed as an unreliable supply.

INTRODUCTION:

BASF often identifies its' power quality by the effects it has on its ability to manufacture products. Improvements are made to remedy the power quality problems either through the elimination of the problems or through some means of overcoming these problems. The approach of addressing the reliability of its utility systems is common within BASF. This paper will address one of BASF's approaches to addressing Power Reliability.

PROBLEM RECOGNITION:

The first issue to address comes in recognizing the problem. It is common that power reliability problems can exist for years before actually being considered problems. Business conditions can improve production levels to the point that recovery from lost production is no longer possible. This is when an existing situation becomes a problem. Operational habits can be a masking activity supporting this delay in recognizing a problem. Operators who have become proficient at restarting the process may retire or become consumed by new activities. Now the brief outages that had been just a part of a day's work become interruptions effecting delivery of product.

Equipment sensitivity can become an issue as the plant operating load increases. As the load increases the distribution voltage may drop slightly causing a piece of equipment to fall outside its' operational parameters. A machine that had never been considered sensitive may now become temper mental. These examples are those of actual cases where manufacturing sites suddenly realized that they had serious problems that must be addressed.

TEAM APPROACH:

Solutions come in a variety of shapes and sizes, as do their analysis. I will describe here a team approach to resolving power reliability issues that has proven successful at a number of BASF facilities. Team approaches are quite common in industry today because of the opportunities they provide for the use of collective intelligence in solving problems. The typical Power Reliability Team at BASF consists of process and power expertise from the facility in question. A representative from the electric power provider is always included 1) for the expertise they commonly have to offer, 2) for the resources they can make available, and 3) because solutions can involve joint funding on the part of BASF and its' provider. Also included on the core team is an individual involved in power quality within BASF to facilitate the Team's efforts and to serve as a technical resource for sharing common solutions among other BASF facilities. This is the role the author has played in nine such team efforts. Power quality expertise is often hired to address site specific needs and to serve as a Team member on a temporary basis.

Planning is an essential part of teamwork. The development of a common understanding of the intent of the Team is addressed early in the planning stages. The creation of a Team Charter clearly explains this intent. I have included below a draft statement that is commonly used as the starting point for developing a Charter.

"*To improve the reliability in an economic manner of BASF's production processes through a cooperative approach involving BASF, and "local" Electric Utility. Improved process reliability, in this case, is defined as identifying/implementing steps to significantly reduce the effects of the electrical events as experienced in past years."*

This Charter is then used to develop Team specific goals, allowable interruption quantity/duration or economic guidelines for the application of solutions. A common goal includes the development of a definition of reliable power as it relates to the processes at the facility. This definition can include limitations on supply voltage variations, a limit in interruption duration, and more. This definition becomes the basis by which ride-through parameters are defined and implemented.

INVESTIGATION:
Once the Team has determined its' goals and how it will operate, it begins the process of identifying the problems. The first step includes identifying the outage history. This history is compared to the electric providers' logs to determine probable causes. Within this history is the identification of specific loads affected by power interruptions. Location of these loads within the site distribution system is included as well as a review of the electric providers' supply one-lines to determine if any commonality exists.

A collection of the costs associated with the various outages and a confirmation of these costs then occurs. It is common at this point that the site may recognize the lack of sufficient information to draw conclusions from, based on the outage history. If this is the case, monitoring equipment will be installed to begin a more accurate accounting of the power situation. Several BASF sites have had sufficient monitoring which served to greatly reduce the remaining efforts of the Team.

CATEGORIZATION:
Once the chronological outage history has been compiled the events are classified into a number of categories. These categories include duration, process area, cost impact, and a determination of avoidability. The costs associated with each event is also categorized and can often lead to an early determination of the economic justification of the types of "fixes" that can be considered.

The reliability of the other utilities within a manufacturing site must also be considered. A process reliant on compressed air may be modified to ride-through a power interruption but if it has insufficient compressed air storage capacity to allow for the time it takes to restart and load its' air compressors it is still an unreliable process. Other utility supplies to consider are steam, refrigeration, nitrogen, cooling water, and raw material supplies. The reliability of each must be addressed to create a reliable system.

IDENTIFICATION OF SOLUTIONS:
Having categorized the various events specific problems may become more evident. If the majority of the problems appear to come from the supply side of the electrical system and sufficient losses are experienced, a higher voltage level of service may be considered. Redundancy in supply can also be considered allowing a supply from an alternate feeder. Redundancy may already exist but may not be operated in parallel or via a fast enough transfer scheme. A change of power suppliers can be an alternative, or possibly a change of primary supplier through self-generation.

A second group of solutions can include a variety of maintenance issues. Repeated outages from tree branches falling on power lines may lead to a more stringent tree-trimming program. Switching transients may require a change in delivery, the installation of reactors, or the removal of capacitors. Lightning protection, grounding, and counterpoising may need attention. Transformer capacity and/or tap settings may be affecting delivery voltage.

Internal fixes may also solve the problems. The installation of constant voltage transformers can provide additional ride-through capabilities, capacitive circuits on x-line voltage starters may be necessary. The relocation of more sensitive loads onto specific feeders can isolate problems and reduce implementation costs. A number of other local fixes have been successfully applied within BASF.

DETERMINING JUSTIFICATION:
During categorization you may have discovered that some of the outages are considered unavoidable. This could be due to extenuating circumstances. Whatever the cause the losses associated with these outages can not be used in the economic justification for the avoidable loss repairs.

Detailed cost analysis is essential in insuring proper repairs are installed. Concern must also be given to the fact that one repair may eliminate the justification of another. For example: increasing the tap settings of a distribution level transformer may raise internal plant voltages sufficiently enough that the majority of your ride-through potential is no longer justifiable. In this case, there may not be a justifiable way to avoid some outages. Remember that if there is no economic justification to solving the problem then the problem may not be large enough to worry about in the first place.

IMPLEMENTATION:
Solutions to power reliability problems can vary greatly in size and scope. When expense dollars are required the repair can often be implemented quickly. Capital funding may require additional time and additional efforts in providing detailed justification. In either case eliminating the majority of the events with the fewest number of options, at the lowest cost, is the desired result.

CONCLUSION:
On-going monitoring is necessary to insure that the proper solutions were implemented and to avoid having the problem re-occur. Periodic reporting requirements can provide one means of insuring that this on-going monitoring is in place.

A change in business conditions can lead to the identification of a problem but can also lead to the elimination of a problem. Basing your solutions on economic justification is the only way to insure that you are making the best business decisions in dealing with your power reliability.

Coal Retirements: Defining the Need and the Efficiency Opportunity

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ABSTRACT

For decades, major areas of the United States have relied heavily on coal for electricity generation. Abundant and relatively cheap, coal has powered large swaths of the Southeast, Midwest, Mid-Atlantic and western United States. Aging equipment and increased environmental compliance needs are changing the economic paradigm for many coal-fired plants. Faced with rising fuel prices and requirements for major investments in pollution control equipment, some utilities expect to retire significant coal generation in the next few years.

This paper will target eleven states that appear to be losing coal generation in the near future. It will discuss the likely amount of generation retirement in each state, based on several publicly available estimates. It will then discuss the role that energy efficiency and combined heat and power (CHP) might play in supplying reliable energy resources in areas that will be facing high amounts of generation retirement. Finally, this paper will discuss the types of policies and regulatory changes that could help encourage the alternative energy efficiency and CHP scheme discussed herein.

INTRODUCTION

About 45% of U.S. electricity generation today is coal-based. Over 1,400 electricity-generating units run on coal in the U.S., and all energy-generating activities from coal account for about one third of all U.S. CO2 emissions (1).

Coal-powered electricity generation will face major economic challenges in the near future. New environmental requirements will raise the cost of operating coal-based plants, while cheap natural gas will challenge the notion that coal is the cheapest energy-generating resource (2). Coal-dependent utilities will assess whether it is more economically advisable to retire existing coal plants (and build new, non-coal plants) or invest in costly pollution controls.

No matter the decision by utilities, utility customers will ultimately bear the burden of increased rates to cover the cost of new generation or pollution controls. It is in customers' best interest, then, for utilities to invest in the most cost-effective energy generation options. One of the cheapest and most quickly deployable energy resources is energy efficiency, especially new combined heat and power (CHP) systems.

CHP is a suite of distributed energy systems that generate electricity and useful thermal energy concurrently, offering overall system efficiencies of up to twice that of traditional centralized energy generation. This is because heat that normally would have been exhausted or otherwise wasted in normal generation is captured and used for a productive purpose with CHP.

In the U.S., CHP has not historically been prioritized as an energy resource, and it continues to face regulatory, economic and policy challenges in many states. As states look to decide how they will power their futures, CHP and energy efficiency present viable alternatives to new centralized generation or increasingly expensive coal-based generators. Such alternatives to traditional "supply side" generation can ultimate save all consumers money while reducing emissions.

PREPARING FOR COAL RETIREMENTS

EPA Regulations

The U.S. Environmental Protection Agency (EPA) is updating at least six rules pertaining to air, water and waste issues that will directly impact coal-fired power plants in the near term (2). Most of these regulations will require that plant owners either invest heavily in pollution controls for their plants or, if such investments prove economically unwarranted, close the plants entirely.

The two rules most directly affecting new and existing coal-fired plants are the Cross-State Air

Pollution Rule (CSAPR) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) rule. Pollutants including NO_X, SO_X, mercury, and particulate matter are regulated by these two rules. The CSAPR applies to generators in 27 states, where it will impact those over 25MW in size. While the CSAPR is currently in effect, it is presently being challenged in the courts. The NESHAP rules will apply to all utility generators and will require investments in pollution control equipment for all coal-fired power generators (3).

The EPA regulations will require existing plants to invest in substantial pollution controls if they have not already done so. These controls could include flue gas desulfurization, to control SO_2; selective catalytic reduction, to control NO_X; activated carbon injection and fabric filters, to control mercury; and dry sorbent injection, to control SO_2 (4).

Estimated costs of these kinds of pollution controls range from $118/kW to $802/kW, depending on the type of control (4). Plant operators have different options for controlling certain pollutants, with certain technologies offering lower up-front costs but higher maintenance costs, and others offering higher up-front costs but lower operating and maintenance costs.

In general, when owners of coal-powered plants are deciding whether to retrofit their existing plants, the cost of building new, likely natural gas-fired generation will be compared to the cost of pollution controls. Larger coal plants will likely find that investing in pollution controls, as opposed to new generation, makes more sense, while smaller systems will find the calculation reversed, suggesting plant retirement as the most economically viable option (4).

Other Economic Factors

In addition to the EPA regulations, coal-powered electricity has begun to face new economic competition from natural gas-fired generation, which is benefitting from stable and low natural gas prices. The existing coal-powered fleet is old, for the most part, with a median initial operating year of 1966 (2). These plants were typically built prior to new, more stringent air regulations, and as a result do not have certain pollution controls in place already (2). With increasing domestic natural gas resources and a recent history of major natural gas investments by utilities, coal-fired generators face a natural gas generation industry rising in popularity and scale.

So while EPA regulations are set to have substantial impacts on existing coal generators, much of the affected coal capacity would already have faced economic challenges to its continued existence.

Retirements Inevitable

While estimates vary widely, it is generally accepted that states heavily dependent on coal will see some coal retirements in the near future. Older and smaller units will be especially less likely to continue to be able to operate economically (4). Some individual utilities have issued press releases suggesting their likely retirements, and some states and regional transmission organizations have done their own analyses to determine how much coal capacity will likely be lost.

One of the regions most affected by the likely retirements will be the area served by the PJM Interconnection, which covers 13 states. Despite the substantial likely retirements – PJM estimates its region will see the retirement of about 23 GW – it still anticipates that major capacity constraints will not occur, because other supply will enter the market in a timely fashion (4).

The remainder of this paper will address the specific coal situation in eleven states, and specific energy efficiency opportunities that could be exploited to ensure a more economically and environmentally sustainable energy future.

IMPACTS ON COAL GENERATION ASSETS

Several organizations have attempted to quantify the amount of coal-fired capacity that will be retired in the near future due to economic challenges and new environmental rules. This exercise is fraught with unknowns, such as future natural gas prices, future energy demand, and possible delays in implementation of the rules. However, informed estimates provide a range of likely coal plant retirements that can be considered.

Most power plants are part of larger transmission organizations and independent markets that regularly trade power across state lines. While estimates for overall retirements and “at risk” for retirement coal plants nationwide range from 25GW by 2015 to 65 GW by 2020, only particular regions are expected to see significant retirements. The Midwest ISO, ERCOT in Texas and PJM in the Mid-Atlantic and Midwest areas are the regional markets that will see the most capacity reductions when coal plants retire in the coming years (10).

Though most power plant operators sell power into a market larger than the footprint of the state in which they operate, it is still useful to observe estimated retirements by state. As will be discussed in the next section, state-level policies and regulations have major impacts on what will replace the retiring plants, and it is at the state level where energy efficiency and CHP can be strongly encouraged and supported as solutions to concerns about capacity constraints due to coal plant retirements.

The authors have identified eleven states as initial targets for this paper due to the amount of older coal plants in each state and the higher likelihood that all energy efficiency opportunities have not yet been explored. The states are: Alabama, Colorado, Georgia, Indiana, Iowa, Kansas, Kentucky, North Carolina, Ohio, South Carolina, and West Virginia.

Table 1 shows the current installed coal capacity and ranges of estimates of coal generation capacity retirement in each of these eleven states, based on analysis from three different sources. Most of these estimates are for plant retirements through 2020, though some include plants that might retire later, depending on regulatory and economic factors.

State	Installed coal capacity (MW)	Range of likely coal retirements (MW)
AL	11054	846 - 3,478
CO	4933	532 - 1,195
GA	13309	1,256 - 2,578
IN	19292	1,663 - 2,019
IA	6815	82 - 1,193
KS	5208	0 - 479
KY	14437	1,713 - 2,180
NC	13312	2,345 - 2,904
OH	21891	2,228 - 4,936
SC	7312	388 - 1,682
WV	14899	1,707 - 3,109

Table 1: Installed coal capacity and estimated likely coal retirements in select states (5,6,7)

What is immediately clear is that the ranges are quite wide, though generally within 1,500 MW or so. Ohio appears to be more affected than any other state, which is in keeping with some of the announcements made by Ohio utilities such as AEP and Duke (8,9). Other states, such as Kansas, will see relatively small amounts of capacity retired.

THE ENERGY EFFICIENCY OPPORTUNITY

The Benefits of Energy Efficiency

These retirements can be looked at as opportunities to replace what was already a rather inefficient and certainly dirty suite of electricity generation assets. While much has been made about the cost of plant retirements and pollution controls, the conversation has largely ignored an alternative that could meet future demand needs, reduce emissions and save consumers money: energy efficiency.

According to ACEEE and Lazard, energy efficiency resources cost anywhere from 1.6 to 3.3 cents per kWh. This makes them remarkably more attractive, on a strictly economic basis, than more traditional generation. According to the same research, natural gas, coal, and nuclear energy range from 6.9 cents to 14.4 per kWh (11).

Energy efficiency offers other benefits in addition to its low cost, however. It reduces overall emissions; it can be deployed quickly compared to traditional generation; it reduces peak demand, minimizing the need for peaking plants; and it reduces the general stress on vulnerable parts of the distribution system (3).

Energy efficiency also has an economic development benefit surpassing that of a traditional centralized generator. Much of the benefit of energy efficiency is its multiplier effect as compared to a business-as-usual case (12). ACEEE has long studied the impact, in terms of jobs and economic activity, of energy efficiency as compared to traditional energy generation. Energy efficiency is far more productive to the economy than traditional generation, and money spent on energy efficiency in turn saves consumers money, yielding even more of a multiplier as consumers spend their saved money in other areas of the economy (15).

Energy efficiency can also help meet the forecasted capacity shortfalls, and can address the demand constraints that worry regulators and policy makers when the long-term effects of the EPA rules are considered (2). Estimates by ACEEE of state-level energy efficiency opportunities routinely show cost-effective energy efficiency to be available at a

scale surpassing that of the estimated coal retirements (2).

Investments to Be Made

As the EPA prepares to enforce several rules, the question of the role of energy efficiency in compliance and as an alternative to pollution controls has emerged. Historically, EPA has supported energy efficiency as a compliance measure for certain air regulations (3). Other programs, such as the Regional Greenhouse Gas Initiative, have shown that energy efficiency investments are viable alternatives to other means of reducing emissions. The actual implementation of the CSAPR rules will likely include substantial energy efficiency opportunities that states can choose to exploit in order to meet emission caps. Retiring certain coal-fired plants and investing in new energy efficiency will yield more cost-effective compliance than simply taking older plants off line and building brand new centralized generation assets.

The EPA has gone so far as to state explicitly that energy efficiency will play a critical and highly cost-effective role in the permitting of new sources of emissions under the Clean Air Act (3). New rules regulating the permitting of CO_2, announced this year, will strongly take energy efficiency into account and efficiency "will be central" to compliance for greenhouse gas emissions in these new rules (3).

Utilities owning and operating coal-powered generation assets will be spending money on energy resources one way or another. Whether they invest in pollution controls or retire affected plants and build new generation, it is estimated that $70-180 billion will be spent on compliance as a result of new regulations and the changing economics of coal-fired generation (10).

Over half the coal plants in the country are lacking at least one major pollution control that will be required by these new rules. For some pollution controls, such as activated carbon injection and baghouse (fabric) filters to control mercury, only a very small percentage – 4% -- of in-place coal capacity is already covered by such controls (10). Owners of coal plants missing critical pollution controls will be making difficult decisions in the next few years about whether to scrap their entire asset or make major pollution control upgrades at very high costs. It is during these considerations that energy efficiency could be considered as a cheaper alternative investment.

COMBINED HEAT AND POWER

One of the best opportunities for increased energy efficiency in industrial and institutional facilities in particular is CHP. CHP is the simultaneous generation of electricity and thermal energy, yielding levels of efficiency of sometimes twice that of traditional electricity generation (13). Besides its higher levels of efficiency, CHP is typically located very near the point of consumption, avoiding transmission and distribution losses in the process.

According to a 2008 study by the Oak Ridge National Laboratory, about two thirds of all fuel used to generate electricity is lost as waste heat. CHP is an effective way to capture that heat and overcome and reverse that statistic to make better use of the fuel (13). As coal plants are retiring, replacing them with the most efficient option – far more efficient than a traditional natural gas-fired generator – would seem to be a wise investment for the long term.

The states targeted by this study have generally not been those that have seen substantial growth in CHP deployment in the last few years. Indeed, only Ohio saw over 100MW of CHP deployment since 2005. Figure 2 highlights the number of new CHP systems and the total operating capacity installed in each target state since 2005.

State	Number of systems	Operating capacity (MW)
AL	3	47
CO	10	14
GA	5	6
IN	8	2
IA	4	20
KS	4	16
KY	0	0
NC	15	18
OH	11	119
SC	5	41
WV	4	1

Figure 2: CHP systems installed since 2005 (14)

A number of reasons contribute to the lack of substantial new CHP investments in these states. For one, many of these states benefit from low electricity prices relative to the rest of the country, making the economics of CHP harder to justify in some cases

(13). In others, the utilities that cover major parts of the states in question have not been incentivized to support or encourage new CHP systems, and instead see CHP as a competitor to their business of selling energy.

As CHP systems require substantial up-front investment, facilities are loath to commit to new investments in expensive equipment unless they know for sure that they will be able to tap into revenue streams, such as financial incentives, or will be able to use such investments to comply with new air regulations.

Regulators and policy makers can substantially change the playing field for CHP and implement policies and regulations that provide incentives and opportunities for facilities to invest in CHP and save money. The following section will discuss some of the opportunities in the eleven target states.

POLICIES AND REGULATIONS

Energy efficiency is cheaper than traditional generation and/or new pollution control measures, creates more jobs, is supported as a compliance mechanism for new federal regulations, and can be deployed faster than new centralized generation resources. It would therefore appear to be highly likely that new investments in energy efficiency will be made in every affected state in lieu of greater investments in new generation assets.

Instead, energy efficiency continues to be downplayed in press releases and public commentary regarding new EPA regulations. While some utilities lament the cost of pollution controls or new generation resources, and warn ratepayers that these types of costs will be passed on in the form of higher rates, energy efficiency is little-mentioned as a cost-effective solution (8,9).

Since utilities will be most directly affected by these new rules, they are the entities most concerned about the immediate economic impact of compliance costs. However, utilities are typically not structured to make substantial investments in demand-side assets such as energy efficiency (2). The main barrier to greater investment by utilities is the lack of structure within which utilities can earn a financial return on investments in energy efficiency.

While 41 states have some sort of cost-recovery mechanism in place to encourage some investment in energy efficiency by utilities, the amount of efficiency relative to traditional generation is still very small (16).

Four of the states – Alabama, Georgia, Kansas, and West Virginia – have no mechanism whatsoever to allow utilities to recover the cost of even minimal investments in energy efficiency (16). For these states, the establishment of a public benefit fund to help pay for energy efficiency would be a very important first step toward encouraging greater investments in energy efficiency or CHP.

Even if a public benefit fund or other method to recover costs of investments in energy efficiency exists, utilities generally perceive investments in traditional energy generation as more lucrative, in terms of return on investment (2). Therefore, a change in regulatory treatment that would allow utilities to earn a similar rate of return on energy efficiency as they do on traditional generation assets would hasten the increased deployment of energy efficiency (2).

ACEEE has begun to advocate for regulatory schemes that would encourage utilities to invest in customer-side energy efficiency. Such investments could then be presented to regulators, who would in turn allow the utility in question to integrate the costs of the investments into their new rates for customers. In the same manner as traditional generation assets, utilities would be able to make long-term investments in energy efficiency technologies with the explicit understanding that their investments will be recouped and provide a financial return within a given number of years.

Other types of policies and regulations can hasten additional energy efficiency. For CHP in particular, most of the target states lack at least several of the important policies or regulations identified by ACEEE in its annual *State Energy Efficiency Scorecard* as critical to CHP deployment (17):

- In Alabama, CHP systems must make do with a complete lack of interconnection standards for distributed generation, no net metering standards, no output-based emission standards, and no preferential treatment for CHP within a renewable or energy efficiency portfolio standard.
- In Colorado, some policies are more favorable toward CHP, but utilities are still not incentivized to pursue CHP and have done little to educate consumers on the opportunity.

- In Georgia, the state lacks many of the policies that would encourage CHP, including an interconnection standard, output-based emissions, renewable or energy efficiency portfolio standards, and net metering standards.
- In Indiana, a more favorable policy situation might encourage CHP, but such systems are not eligible for any incentives, nor is there a binding portfolio standard that might offer additional revenue streams to CHP system owners.
- In Iowa, CHP systems are not eligible for any incentives unless they are smaller than 5MW and powered by "renewable" fuels, nor are they able to take advantage of any output-based emission standards.
- Kansas and Kentucky both technically have interconnection standards to work within, but the standards are not designed for larger units. The states also both lack output-based emission standards and carve-outs for CHP in any portfolio standard.
- In North Carolina, a substantial CHP investment tax credit has done very little to stimulate new CHP, due in part to the lack of encouragement by area utilities.
- In Ohio, efforts to support CHP have been quite strong by advocacy groups, though the utilities are still asking to see a business structure change to allow them to earn a return on investments in CHP.
- In South Carolina, a weak interconnection standard, a lack of output-based emission standards, and a lack of portfolio standards all conspire to discourage CHP; and
- In West Virginia, there are some supportive CHP policies in place, but the state does not offer any financial incentives and only "recycled energy" qualifies for the portfolio program.[1]

So while each of these target states have certain supportive policies in place, there remains tremendous opportunity for policies and regulations that might further encourage CHP deployment.

In the eleven target states, overall deployment of CHP capacity in the last few years has been very small relative to the projected coal capacity retirements in future years. However, past performance does not indicate future performance, because the economic potential for CHP in many of these states remains quite high, and all of the available policies and regulations that might encourage more CHP are not in place. These states are just waiting for the right policy and regulatory framework to be put in place to take advantage of the opportunities for cost-effective and emissions-reducing CHP (18).

A major opportunity just beginning to be considered by states and utilities is the aforementioned change in the business structure under which utilities operate. This might take the form of incentives for shareholders that scale based on the amount of energy efficiency deployed by a utility (2). While a very few number of states have such a structure now, such models could be put into place around the country (19).

CONCLUSIONS

Certain U.S. states will see substantial retirement of existing coal capacity due to aging plants and new environmental regulations. Utilities in these states that choose not to retire existing coal plants will instead spend billions of dollars on pollution controls. Knowing that dollars spent on energy efficiency have a greater overall economic benefit than dollars spent on new generation or pollution control, the prudent policy decision would be to retire coal plants and instead invest in new energy efficiency.

Future research by ACEEE will address the known technical and economic potential for CHP in particular in these target states (18). CHP potential has been far from fully exploited in these states, and its substantial efficiency benefits over standard energy generation would offer systems users more bang for their fuel buck.

The technologies to greatly improve overall energy efficiency exist today, but policy and regulatory changes must be put in place in order to ensure that utilities fully explore and exploit these opportunities. Current business models under which utilities operate do little to encourage greater investments in energy efficiency, because such investments do not yield the same returns on investment as investments in traditional generation assets.

The tremendous amount of investment about to be made in the energy generation sector could be instead made in energy efficiency and CHP, locking

[1] These state-level insights are culled from two main resources (13,17). Details of CHP policies and why some policies are better than others can be found in source 13.

in greater energy savings and emission reductions for generations. The right policies and regulations could ensure that such investments in energy efficiency occur.

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A novel approach to heat transfer enhancement using trapezoid shaped spiral strips to promote tumble and swirl in a slot shaped channel used in heat exchangers

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ABSTRACT

Heat transfer results for a given slot shaped channel with a 3:1 aspect ratio are presented using various configurations of a trapezoid shaped spiral wound strips to enhance swirl and tumble motion in the channel. The Reynolds numbers investigated range from 10,000 to 50,000 and are based on the characteristics of the fluid at the channel inlet. The ratio of absolute temperatures between the wall and fluid are on the order of 0.8 to 0.9. A combination of thermochromic liquid crystal techniques and thermocouples were used to create a temperature vs. time map. Duhamel's superposition theorem was then used to determine the local heat transfer coefficients (h) and heat transfer enhancement factors (Nu/Nu_o). In one series of testing a straight center inlet with a radiused entry was used to reduce entry effects.

In a second series of test a 90 degree inlet geometry was used to enhance turbulence at the entry. Three combinations of helical strips were tested using a single, double, and pentuple spiral design. The pitch of the helix remained constant in all tests at 0.75" (18 mm) as well as the height of the strip at 0.0625" (1.6 mm), yielding a p/e (pitch/rib height) ratio of 12. The resulting flow in the channel creates a tumble motion as the main channel fluid encounters the strips and a swirl motion as the fluid is directed through the spiraling helix. Many studies involving heat transfer using swirl enhancement have been presented in literature using round passages with wire spring inserts or twisted tapes, typically used in heat exchangers. In turbine aero foils, particularly in the mid-span region, rectangular channels with various configurations of trip strips are used to enhance heat transfer. The results of the tests presented in this paper show local heat transfer enhancement (Nu/Nu_o) values greater than seven and subsequent average values for the entire channel greater than three at the higher Reynolds numbers along with relatively low normalized friction factors.

NOMENCLATURE

a	Width of slot channel, *in*
b	Height of slot channel, *in*
AR	Aspect Ratio, a/b
d_h	Channel Hydraulic Diameter, *in*
e	Trip strip height, *in*
f	Friction coefficient
f_o	Normalized Friction coefficient
h	Convection Ht. Trans. Coef., $Btu/ft^2\ hr\ ^oF$
k	Coef. of thermal conductivity, $Btu/ft^2\ hr\ ^oF$
L	Channel Length, *in*
Nu	Nusselt Number
Nu_o	Nusselt Number in a smooth round tube
p	Pitch, *in*
Pr	Prandtl Number
P	Pressure, H_2O"
Pm	Pressure, Main Channel, H_2O"
Re	Reynolds Number
t	time, *s*
T_w	Wall temperature, ^oF
T_i	Initial temperature, ^oF
$\Delta T_{m,I}$	Temp. difference between each time step, *s*
U_m	Mean Velocity, *ft/s*
T_m	Centerline/Mean Fluid temperature, ^oF

Greek

α	Coefficient of thermal diffusivity, ft/s^2
ρ	Density, lb_m/ft^3
τ	Time step for each temperature step, *s*
η	Overall Thermal Performance $(Nu/Nu_o / \Delta P/\Delta P_o)^{1/3}$

Acronyms

TLC	Thermochromic Liquid Crystal

INTRODUCTION

Enhancing heat transfer by using swirl enhancement is not new. But recent published literature indicates that significant gains may be possible with the right swirl enhancement techniques.

Smith, et-al [1] studied the effect of helical tape inserts in a round tube like that typically used in a shell and tube heat exchanger. The helical tape induces a swirl motion in the tube that enhances turbulence. Different helical pitches and designs were used and water was used as the fluid in the pipe. Although the study looks Reynolds numbers of 10,000 or less, the graphical results of the study can be extrapolated to higher Reynolds numbers and may prove useful for turbine blade cooling using air instead of water. A 160% increase in mean Nusselt number was obtained in one particular test with other tests showing slightly lower values. The friction loss was up to seven times higher than a smooth pipe.

Adding ribs to a smooth channel induces vortices and flow reattachment as the fluid encounters the rib. The shape, angle, height, pitch, and layout of the ribs in the flow channel can affect the local and regional heat transfer in many ways.

In turbine aero foils, the cooling passages in the mid-span of the blade are typically rectangular in shape. The trend is to use trip strips placed at various angles to enhance heat transfer, with a 45 degree angle providing the optimum results in most cases. The optimum pitch is generally in the range of 8 to 15, depending on Reynolds number, etc.

In Figure 1 the concept of flow over strips placed in the path of the flow experiences flow separation, recirculation, and reattachment. The two sketches show how the reattachment location changes as well as the size of the recirculation zones when pitch and Reynolds number change.

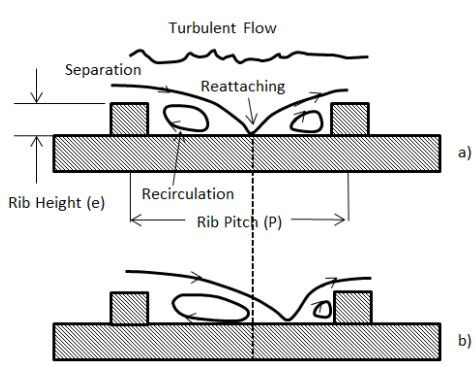

Figure 1: a) Concept of flow over a ribbed surface.
b) Same as a), except increase Reynolds number.

When the strips are placed at an angle relative to the flow, the fluid velocity vector is skewed as it tumbles over the angled strip and the vortices become larger in the downstream flow. Figure 2 shows this concept. Most studies of internal turbine blade cooling use trip strips on two sides of the rectangular shaped channel, but do not incorporate strips on the other two sides.

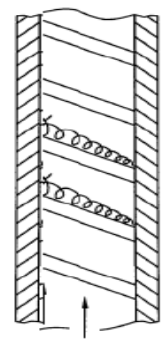

Figure 2: Concept of turbulence induced by angled trip strips in rectangular channels.

Wang, et-al [2] performed a detailed study of various rib shapes placed normal to the flow in square ducts with p/e ratios varying from 8 to 15 and $e/d_h = 0.1$. The range of Reynolds numbers tested was 8,000 to 20,000.

Line plots of the average Heat Transfer Enhancement values verses the p/e ratio is shown in Figure 3. While the trapezoid shape, with decreasing height in the flow direction, clearly seems superior with regards to heat transfer enhancement it should also be noted that the square rib performs as well when the p/e ratio is 10.

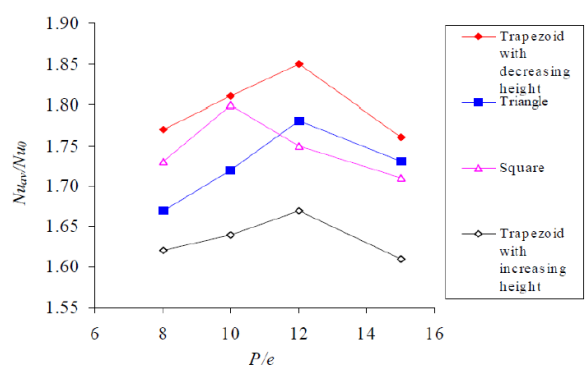

Figure 3. Average Heat Transfer Enhancement for Various Shaped Ribs, Re=20k, Ref. [2].

Many other published papers conclude that a p/e ratio of 10-12 yield the best results at Reynolds numbers associated with turbine blade internal cooling. Not only did the average heat transfer enhancement (Nu/Nu_o) values change, but it was clear that some combinations of pitch and shape offered a more even distribution of enhancement between the ribs. Also note in Figure 3 that each of the various rib shapes exhibit peaks and valleys in the heat transfer enhancement values as the p/e ratio changes. Changes in Reynolds number show similar trends of peaks and valleys when tested at a constant p/e ratio.

The benefits of the uniform heat transfer characteristics displayed in continuous helical inserts used in round tubes in heat exchangers combined with an optimally shaped trip strip in an open slot shaped channel were contributing factors in the configurations chosen for this study.

CONFIGURATIONS STUDIED

A 3:1 single passage slot shaped channel with a hydraulic diameter d_h of 0.976 inch (0.0248 m) and a L/d_h of 8.8 is chosen for this study, due to limitations of the test vessel and to keep in line with typical turbine blade channel dimensions. The various configurations investigated to enhance heat transfer include three variations of helical shaped-trip-strips and two variations of entry geometries. The fluidic swirl-generation configurations are shown in Figure 4, one with a center entry flow into the channel and the other with a 90 degree entry flow into the channel.

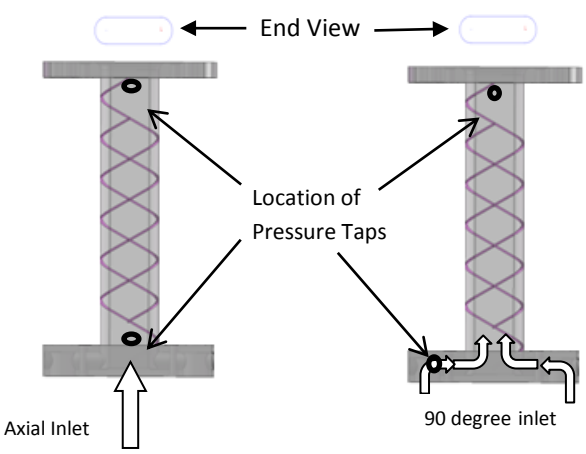

Figure 4. Transparent View of Test Piece with Double Helix Trip Strips in Main Channel

The helical insert concept has been well explored in the heat exchanger community and is an accepted practice for heat exchangers such as tube-in-shell heat exchangers. However, its use in gas turbine cooling has not been extensively investigated. In the present study, a helical trip-strip concept is combined with trip-shaping to obtain added benefits.

As noted by Wang, et al [2], a trapezoidal-cross-section trip-strip with a sloping face at 11 degrees provides increased heat transfer coefficients when compared to rectangular, triangular, round, or other various shapes. For this reason the trapezoid shaped helical trip strip shape was used for all testing. Figure 5 depicts the cross section shape used for this study.

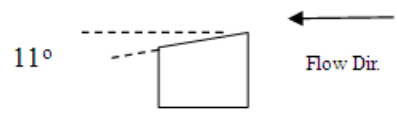

Figure 5: Cross Section Shape of Trip Strip

The strips are attached to the walls of the slot shaped channel in such a fashion as to form a helix. Figure 6 shows two views of the single helix strip. The image on the left shows the helical strips atttached to one side of the channel. The image on the right is a transparent view showing the strips on both sides of the test piece. The helical pattern is clearly visible in this image. Note also that the pitch is maintained at 0.75 inches (18 mm) for this test setup as well as the others.

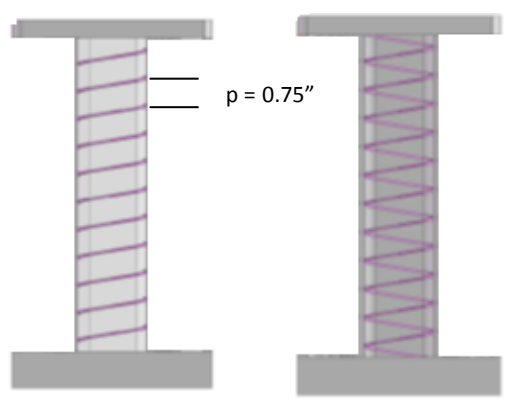

Figure **6**: A slot channel with a single helix trip strip: (LH): as viewed from one side, (RH) a transparent view showing helix on both sides.

In Figures 7 and 8 it becomes clear that the angle of the trip strips relative to the incoming flow becomes more pronounced. The transparent view details the complexity of the trip strip arrangement

that is not so easily realized by the image of one side only.

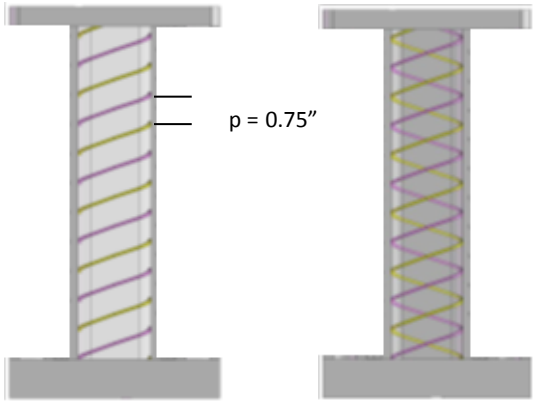

Figure 7. A slot channel with a double helix trip strip: (LH): as viewed from one side, (RH) a transparent view showing helix on both sides.

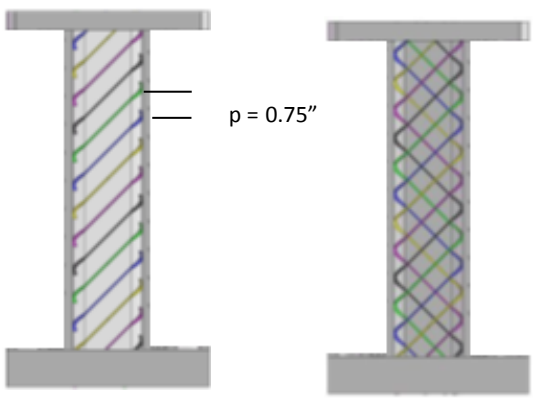

Figure **8**. A slot channel with a pentuple helix trip strip: (LH): as viewed from one side, (RH) a transparent view showing helix on both sides.

EXPERIMENTS

A simulated clear polycarbonate test piece was built that incorporates two strategies for inducing swirl motion in the internal passages of a heat transfer channel. The main cooling channel is slot shaped with an aspect ratio of 3:1, with a height of 0.625 inches (15.9 mm) and a width of 1.875 inches (47.6 mm). The overall length of the slot channel is 8.6 inches (218 mm), not including the entry and radiused exit portion of the channel. As noted earlier, one method uses a trapezoid shaped rib that protrudes into the coolant flow stream with axial flow entering the channel through a 0.5 inch (13 mm) radiused entry. This trapezoid shaped rib spirals along on the wall of the passage for its entire length. The trapezoid cross section incorporates an 11° downward trailing edge along the top surface of the rib and has an overall height of 0.0625 inches (1.6 mm). This shape has proven to be beneficial in ribbed passages without any swirl enhancements [2]. The trapezoid shaped ribs are arranged in either a single helix, a double helix, or a pentuple helix configuration. Reynolds numbers ranged from 10,000 to 50,000 for each of the two entry shapes and three helical designs.

Initial static testing was performed using 25 thermocouples strategically placed in the passage of the channel. A smooth channel with no swirl inducement strategies was tested first, and the results of normalized heat transfer enhancement and pressure losses were used to compare against all tests with swirl enhancements as well as a smooth round pipe with an equivalent hydraulic diameter. Testing with thermocouples as well as thermochromic liquid crystal techniques will provide a more detailed account of heat transfer enhancement in the passage.

In the case of the axial entry, heated air enters the test piece via a long diffuser section through a 0.5 inch (13 mm) radiused entry and exits the single flow slot shaped channel in an identical fashion. The air exits the channel into the atmosphere. The main channel inner walls are coated with a specially prepared thermochromic liquid crystal (TLC) substance which turns green at a nominal temperature of 95 ^{o}F (35C). Two thin film thermocouples are attached to the walls, one near the entry and one near the exit of the main channel. These will be used to confirm the accuracy of the TLC at those locations. Five fine wire thermocouples (0.005”) are placed, equally spaced, in the flow stream with the temperature sensing junction located in the center of the flow channel. These five thermocouples measure the centerline temperature of the air as it progresses through the channel. The thermocouples are wired directly to a Labview thermocouple data acquisition system. The thermocouples have a maximum resolution of 20 Hz and the data acquisition system is set to read thermocouple data at 15 Hz.

In order to view the heat transfer characteristics on the interior of the channel the TLC is applied directly on to the inner wall of the clear polycarbonate channel. A black paint is applied over the TLC and the trip strips are applied over the black paint. The adhesive used to apply the trip strips have the same heat transfer properties as polycarbonate. This special adhesive allows for more accurate results under the trip strip, which act as thin fins to conduct heat. A concept sketch of the application of the TLC is shown in Figure 9.

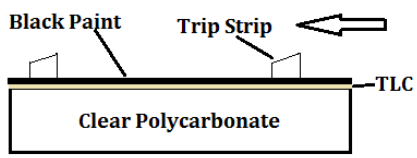

Figure 9. Detailed cross section of test piece showing application of thermochromic liquid crystal.

Two Canon SD430 wireless cameras are securely mounted on each side of the test piece. The cameras are set to record video images at 15 Hz. The thermocouple data acquisition system and the video cameras are synchronized via cold cathode fluorescent lamps (CCFL) that are used to illuminate the TLC and are triggered by a switch attached to an air bypass valve.

Prior to the start of a test, heated air is allowed to bypass the test section. Once the bypassed heated air temperature has stabilized at approximately 176 ^{o}F (80 C) preparations for the start of a test begins. The test piece is also maintained at room temperature for an extended period prior to the start of a test to ensure a uniform initial temperature.

To begin a test, the thermocouple data acquisition system is activated and the cameras begin recording. Then a bypass valve is closed allowing heated air to enter the test piece. The operation of the bypass valve activates the CCFL lamps, which illuminate the test piece at the same time that the heated air enters the channel. Video images and thermocouple are stored for post-test processing.

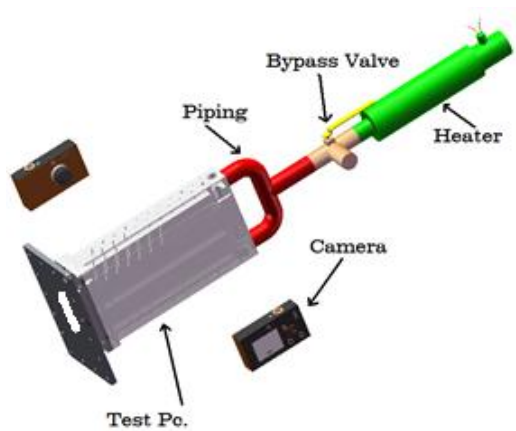

Figure 10: Concept sketch of test set up for the 90 degree entrance test.

In the case of the 90 degree entry, heated air exiting the bypass value is divided and enters the test piece as shown in Figure 10.

HEAT TRANSFER COEFFICIENTS

The local heat transfer coefficients across a liquid crystal coated target surface can be obtained using the 1-D transient heat conduction model of a semi-infinite solid with a convective boundary condition as given by:

$$\frac{\partial T}{\partial t} = -k\frac{\partial^2 T}{\partial x^2} \qquad \text{(Eq.1)}$$

with boundary and initial conditions:

$$T(x = 0, t = 0) = T_i$$
$$T(x = 0, t \to \infty) = T_\infty \qquad \text{(Eq. 2)}$$
$$T(x \to \infty, t) = T_i$$
$$-k\left.\frac{dT}{dx}\right|_{x=0} = h(T_w - T_\infty)$$

The solution for the surface temperature response with regard to time suggested by Incropera [3] is:

$$\frac{T_w - T_i}{T_\infty - T_i} = 1 - exp\left(\frac{h^2\,\alpha t}{k^2}\right) erfc\left(\frac{h\sqrt{\alpha t}}{k}\right) \qquad \text{(Eq. 3)}$$

All variables shown in Equation 3 are available based on material properties or temperature data collected during the test, with the exception of the heat transfer coefficient (h). Duhamel's superposition theorem, Equation 4, can be applied and solved for the heat transfer coefficients at each pixel location of the video image.

$$T - T_i = \sum_{i=1}^{N}\left[1 - exp\left(\frac{h^2}{k^2}\,\alpha(t-\tau_i)\right) erfc\left(\frac{h}{k}\sqrt{\alpha(t-\tau_i)}\right)\right]\Delta T_{m,i}$$

(Eq. 4)

For turbulent fully developed flow inside a circular tube of diameter D and length L, the following relationship is suggested by Dittus.

$$Nu_D = 0.023\,\mathrm{Re}_D^{4/5}\,\mathrm{Pr}^n \qquad \text{(Eq. 5)}$$

n = 0.3 for cooling the fluid and n = 0.4 for heating the fluid

$$(0.6 < \mathrm{Pr} < 160, \mathrm{Re}_D > 10{,}000, \frac{L}{D} > 10)$$

The Nusselt number is the relationship between heat transfer caused by convection to those related to pure conduction. The Dittus solution for determining the Nusselt number in a round smooth pipe without any heat transfer enhancement provisions shown in Equation 5 will be the basis for normalizing the data obtained in this study. The Nusselt number for the smooth pipe relationship with an equivalent hydraulic diameter to the slot shaped test piece is referred in this paper as Nu_o. This value changes as the Reynolds number changes.

A single transient test using the liquid crystal method described earlier is used. Each pixel value is examined for its peak in local intensity. The intensity value is used in conjunction with a specifically written MATLAB program to determine the corresponding time at which the TLC turns green, indicating that the temperature at that particular pixel has reached the TLC specified value. By measuring the corresponding time required for the surface temperature to reach this temperature, the local heat transfer coefficient for each pixel in the image can be determined using Equation 4.

The heat transfer coefficient at each pixel is used to determine the Nusselt number at that pixel. The Nusselt number is defined as;

$$Nu = \frac{h\, d_h}{k_f} \qquad \text{(Eq. 6)}$$

where,

h = heat transfer coefficient
d_h = hydraulic diameter of the slot channel
k_f = the thermal conductivity of the fluid

The 1D semi-infinite solid assumption must be satisfied. In order to satisfy the semi-infinite assumption, the transient temperature must not penetrate through the thickness of the polycarbonate during the test duration. This is achieved by a sufficiently thick test piece of low thermal conductivity and diffusivity (0.201 W/mK and 0.1046 $x10^{-6}$ m^2/s for polycarbonate, respectively). For the one-dimensional heat transfer assumption to be satisfied, conduction should only occur normal to the surface with all lateral conduction effects neglected. Although the test piece may actually experience some lateral conduction, it is assumed that the dominant temperature gradient is in the direction perpendicular to the surface, and lateral effects are negligible.

The initial temperature of the polycarbonate is uniform at ambient temperature, the incoming fluid temperature is higher and not a linear step increase. This is accounted for through the modification of Equation 3 by Duhamel's superposition theorem, Equation 4 which represents the temperature change as a series of steps where τ is the time step for each temperature step, $\Delta T_{m,i}$ is the temperature difference between each temperature step and the initial temperature, (T_i) The values of α, and k are characteristic of the polycarbonate plate.

PRESSURE TEST

A pressure tap is located at each end of the main channel, as shown in Figure 4. Inlet pressures and temperatures are used to determine air density values and used to determine Reynolds numbers and mass flow rates. Pressure drops along the main channel are recorded and used to determine the channel averaged Overall Thermal Performance (OTP). Equation 7 shows the relationship between the thermal enhancement value and the differential pressure loss.

$$\eta = \frac{\frac{Nu}{Nu_o}}{\left(\frac{\Delta P}{\Delta P_{\,smooth\,round\,pipe}}\right)^{1/3}} \qquad \text{(Eq. 7)}$$

The location of the pressure taps are shown in Figure 4.

HEAT TRANSFER CONTOUR PLOTS

Analyzing the Images

Once the equations are solved for the local heat transfer coefficient at each pixel the results can be plotted as a function of the heat transfer enhancement factor. To better understand the details of the heat transfer coefficient distributions, contour plots of the spatial distributions are presented.

RESULTS AND DISSCUSSION

Pressure Loss

The results of the pressure loss measurements are displayed in Figure 11. It is expected that the pressure loss would be significantly higher for the 90 degree entry cases. As seen in the chart, the pressure loss is approximately double when the 90 entry values are compared to the axial entry configurations.

The worst case occurs at the highest Reynolds numbers where the pressure loss more than triples for the 90 degree entry when the pentuple trip strips are compared to the axial entry case with pentuple trip strips, when values at Re = 50k are 9.35

H_2O" for the 90 degree case and 2.85 H_2O" for the axial enter case.

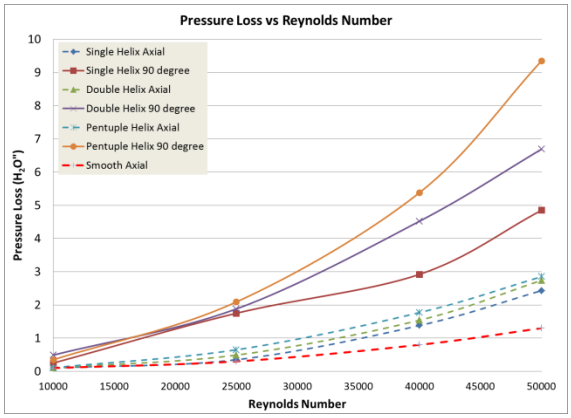

Figure 11. Pressure Loss vs. Reynolds Number for all Seven Configurations Tested.

Smooth Channel – Axial Inlet

For comparison purposes Nu/Nu_o plots of the slot shaped channel with a 0.5" (13 mm) radiused entry and air entering thorough a axial entry is shown in figures 12-15. The radiused entry reduces the turbulence at the entry, but does not eliminate heat transfer from occurring at the entrance. In all cases shown, the heat transfer enhancement becomes negligible near the exit.

The Nu/Nu_o values are 1.04, 1.11, 1.28, and 1.32 for Re=10k, 25k, 40k, and 50k respectively. In all four cases presented, the smooth channel with no heat transfer enhancement strategies show some high Nu/Nu_o values at the entrance to the channel and then gradually reduces to no significant enhancement near the exit of the channel.

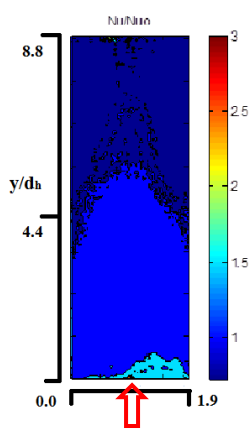

Figure 12: Heat Transfer Enhancement (Nu/Nu_o) for a Smooth Slot Channel, Re = 10k ($h_{avg.}$ ~ 40).

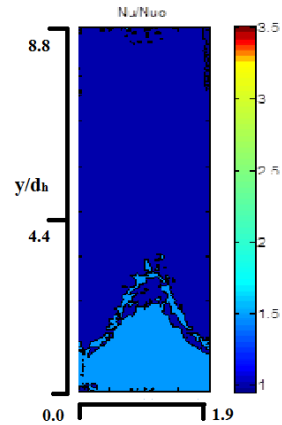

Figure 13. Heat Transfer Enhancement (Nu/Nu_o) for a Smooth Slot Channel, Re = 25k ($h_{avg.}$ ~ 75).

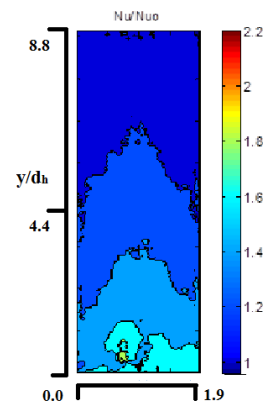

Figure 14. Heat Transfer Enhancement (Nu/Nu_o) for a Smooth Slot Channel, Re = 40k ($h_{avg.}$ ~ 127).

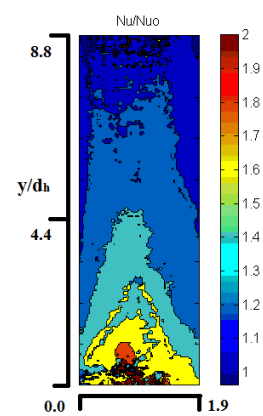

Figure 15. Heat Transfer Enhancement (Nu/Nu_o) for a Smooth Slot Channel, Re = 50k ($h_{avg.}$ ~ 160).

Single Helix – Axial Inlet

Plots of the normalized Nusselt number are presented for the single helix with axial flow entry in Figure 16.

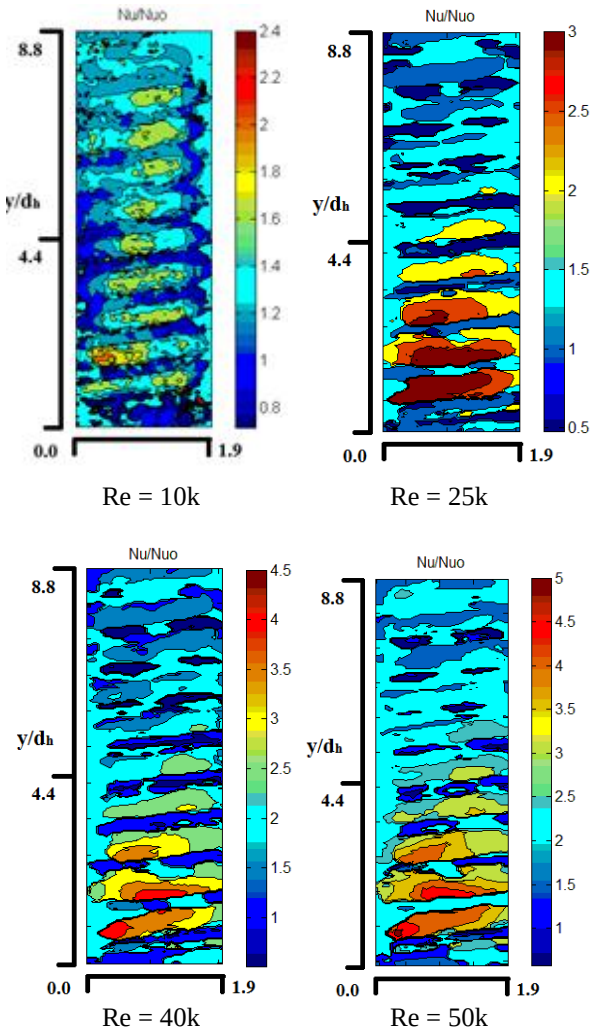

Figure 16. Heat Transfer Enhancement (Nu/Nu_o) for a Single Helix with Axial Entry at various Reynolds Numbers.

In reviewing the plot of Re = 10k in Figure 16, it is noted that as the fluid enters the channel minimal enhancement is apparent prior to the fluid contacting the first helix of the trip strip.

The enhancement quickly improves once the first helical strip is encountered and values of Nu/Nu_o 1.8 are noted locally in the channel. As the flow progresses the effect of the enhancement is reduced and stabilize to a range of 1.3 near the exit of the channel. The mean Nu/Nu_o for this configuration is 1.10, with an overall thermal performance factor of 1.10 at Re=10,000.

As the Reynolds number was increased to 25,000 and beyond, the same trend as in the 10,000 Reynolds number case was observed. For the 25,000 Reynolds number case the overall mean thermal performance increased to 1.71 with a mean heat transfer enhancement value of 1.62. As expected, the same lack of significant enhancement is noted at the entry in the figure. The enhancement sharply increases following the first trip strip to values of greater than three and maintain local values in excess of 1.5 throughout the channel to the exit, but these local areas diminish in size as the flow progresses through the channel.

As the Reynolds number is increased to 40,000 and 50,000 the increase in mean overall thermal performance increases significantly to 2.34 and 2.66, respectively. As seen in Figure 16, a small region of an enhancement value of five is noted after the first trip strip and diminishes as in previous plots. Very small regions of high Nu/Nu_o values exceeding two are noted near the exit.

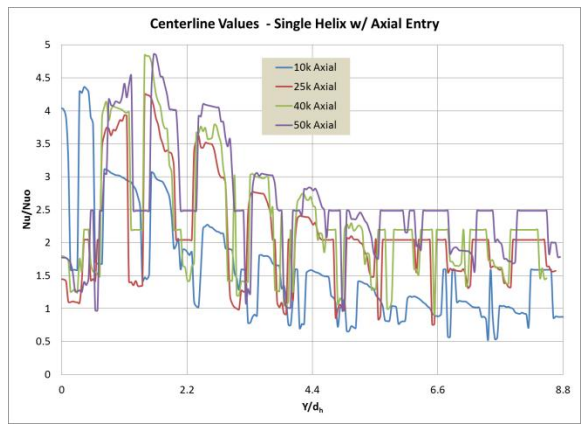

Figure 17. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Single Helix with Axial Entry.

One way to compare the performance of this grouping of test is to plot the centerline values of Nu/Nu_o vs. position along the flow path. Figure 17 shows all four single helix tests superimposed onto a single graph. The peaks occur in between the trip strips and the valleys indicate the location of the trip strips. Wide peak indicate localized uniformity of heat transfer enhancement.

Single Helix – 90 Degree Inlet

Converting the test piece from the axial entry with a 0.5" radius to the 90 degree entry involves changing the entry adapter. The air will now enter the test piece as shown in Figure 4. The air must make two 90 degree turns prior to entering the main channel of the test piece. This creates

substantial turbulence, which leads to high heat transfer enhancement at the channel entry.

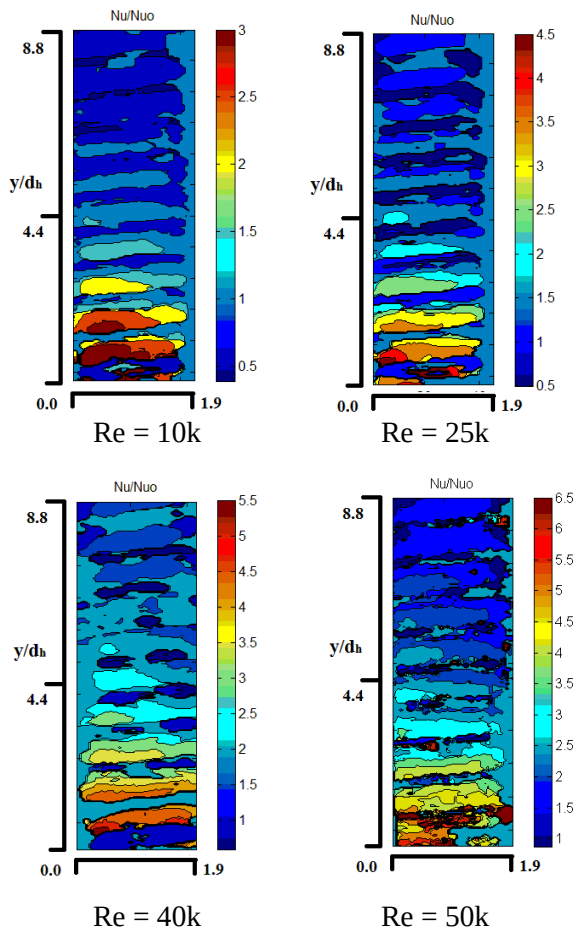

Figure 18. Heat Transfer Enhancement (Nu/Nu_o) for a Single Helix with 90 Degree Entry at various Reynolds Numbers.

Much higher enhancement values are observed at the entry when the 90 degree entry configuration is used in conjunction with the single helix trip strips. There is increased turbulence caused by the two opposing flow regimes as the air enters the main slot shaped channel. High heat transfer values are apparent before the flow encounters the first trip strip. This initial turbulence enhances the heat transfer characteristics throughout the rest of the channel.

The color contour plots in Figure 18 show the heat transfer enhance in the channel when the single helix trip strips are used in conjunction with fluid flow entering the channel at a 90 degree angle relative to the main channel flow direction. The channel averaged heat transfer enhancement values are 1.26 for the 10,000 Reynolds number case and 2.46 for the 25,000 Reynolds number case. The overall thermal performance values are 0.93 for the 10,000 Reynolds number test and 1.36 for the 25,000 Reynolds number test.

At the higher Reynolds numbers the heat transfer enhancement values did not show much higher values than the Re = 25k case. The Re= 40k average Nu/Nu_o value was slightly less than that of the Re=25k case at 2.35 and the Re = 50k value is 2.85. However, when pressure losses are taken into account the overall thermal performance values were markedly higher than the Re = 25k case with OTP values for the Re = 40k test of 1.52 and for the Re = 50k test an OTP value of 1.84.

In all cases the heat transfer distribution along the entire channel was not uniform, with values near the entry typically two to three times higher than values near the channel exit.

The centerline values of Nu/Nu_o are shown in Figure 19. In many cases the centerline plots may be a better indicator as to the uniformity of heat transfer enhancement.

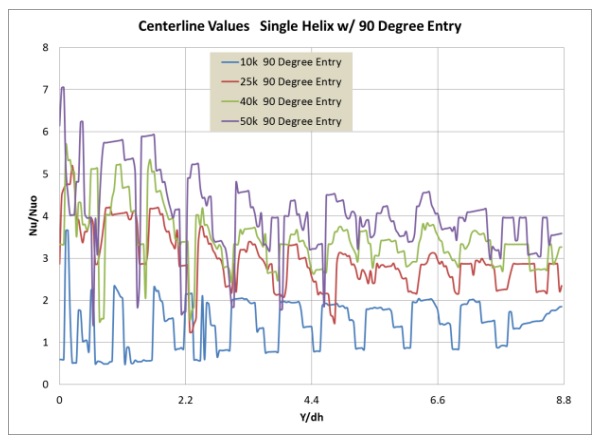

Figure 19. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Single Helix with 90 Degree Entry.

<u>Double Helix – Axial Inlet</u>

Figure 7 shows the layout of the double helix trip strips. Even though the spacing of the strips is maintained at a pitch of 0.75", each separate strip has its individual pitch of 1.5". This allows turbulence created on one wall by the inclusion of a trip strip in the flow path to influence the flow stream on the opposite wall of the test piece.

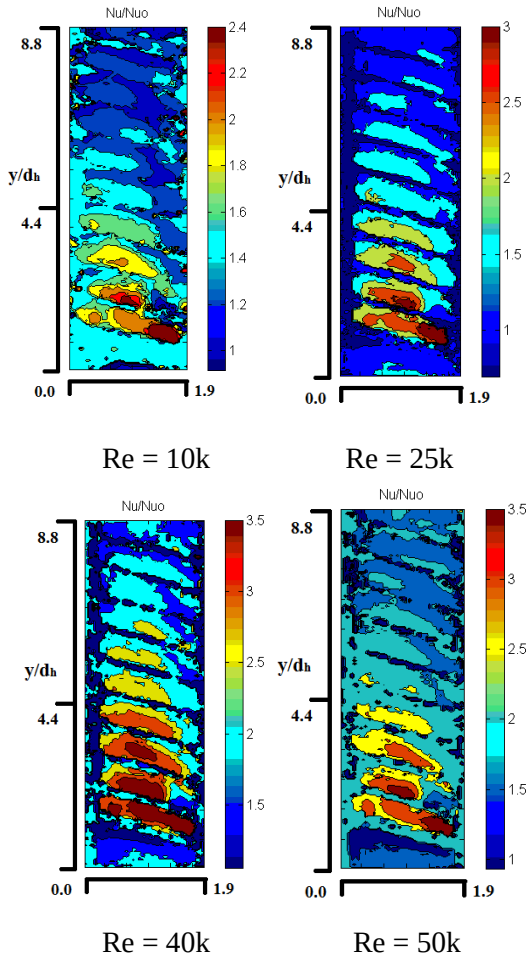

Figure 20. Heat Transfer Enhancement (Nu/Nu_o) for a Double Helix with Axial Entry at various Reynolds Numbers.

The double helix trip strip configuration exhibited the best heat transfer enhancement and the best overall thermal performance values of all three trip strips tested. Figure 20 shows the color contour plots of Nu/Nu_o vs. position along the flow path for all four Reynolds numbers tested with the axial entry. The tendency of high Nu/Nu_o local values occurring just after the first trip strip are present here also.

Test results yield a heat transfer enhancement value of 1.48 for Re = 10k, 1.53 for Re = 25k, 2.15 for Re = 40k, and 2.04 for Re = 50k. The overall thermal performance was very high with values of 1.45, 1.29, 1.73, and 1.59 for Reynolds numbers of 10k, 25k, 40k, and 50k, respectively.

The centerline values of Nu/Nu_o are shown in Figure 21. For the higher Reynolds number cases, Nu/Nu_o values of greater than two are maintained throughout the channel.

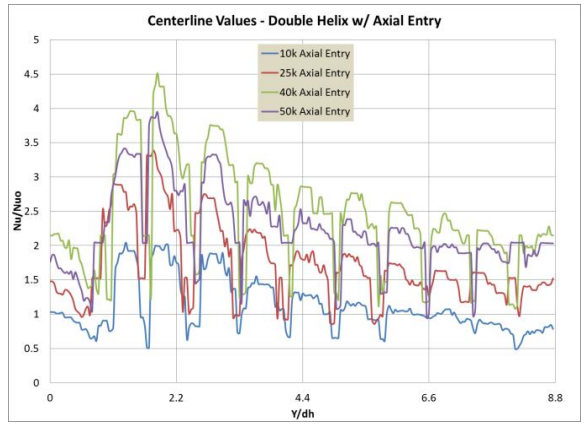

Figure 21. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Double Helix with Axial Entry.

<u>Double Helix – 90 Degree Inlet</u>

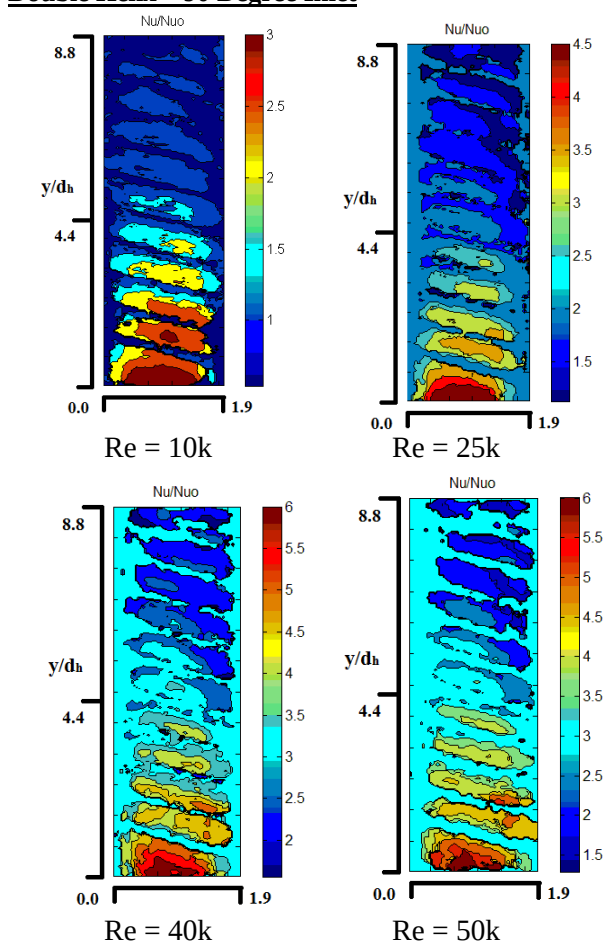

Figure 22. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Double Helix with 90 Degree Entry.

The double helix combined with the 90 degree entry configuration had superior heat transfer enhancement to all other combinations tested. The heat transfer distribution in the channel was the most uniform of all tests, especially at the higher Reynolds numbers. This is shown in the images in Figure 22.

Nu/Nu_o values for the Re = 10k test were 2.05, which is considerably higher than the 1.48 value for the double helix strips used in conjunction with the axial entry. The values of the normalized Nusselt numbers for the Re= 25k, Re = 40k, and Re = 50k tests were 2.26, 3.37 and 3.37, respectively. The overall thermal performance (OTP) values were also the highest of the various test configurations with values of 1.21, 1.23, 1.89, and 1.95 for the 10k, 25k, 40k, and 50k Reynolds number test, respectively.

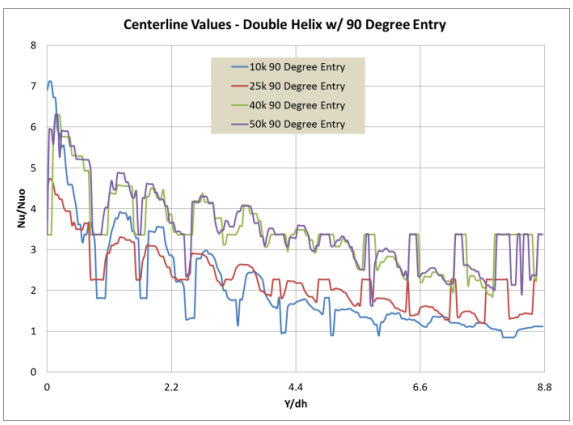

Figure 23. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Double Helix with 90 Degree Entry.

The centerline values of the double helix, 90 degree entry configuration are shown in Figure 23. At the higher Reynolds numbers the ribs, which act as thin fins, conducted enough of the heat onto the outer wall to substantially add to the overall performance. This can be seen by observing the small amplitude between the peaks and valleys in the centerline plots.

<u>Pentuple Helix - Axial Inlet</u>

The complexity of the trip strip profile can be seen in the transparent view of the test piece utilizing the pentuple trip strips in Figure 8. The pitch of the strips remains at 0.75", but each individual strip has a pitch of 3.75". This causes the angle of the individual strips to be at a 64 degree angle relative to the flow path. This strategy creates a chaotic path for the fluid which resulted in a more equal distribution of heat transfer in the channel. The penalty was the increase in pressure loss.

The images in Figure 24 detail the Nu/Nu_o behavior using the pentuple trip strip arrangement with the fluid entering the channel axially. Other than the initial high heat transfer areas at the beginning of the channel, the remainder of the channel exhibits a more uniform distribution than all of the other configurations tested.

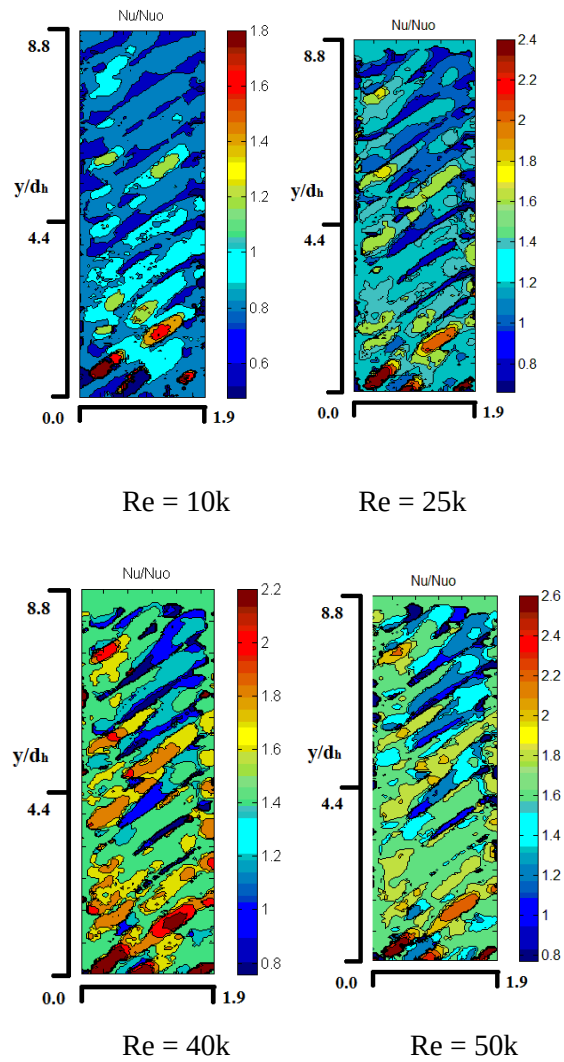

Figure 24. Heat Transfer Enhancement (Nu/Nu_o) for a Pentuple Helix with Axial Entry at various Reynolds Numbers.

The 50,000 Reynolds number test provided the best results for this configuration yielding a channel averaged normalized Nusselt value of 1.63, which translated to an OTP value of 1.26. The other configurations had values of Nu/Nu_o of 1.01, 1.33,

and 1.63 for Re = 10k, Re= 25k, and Re = 40k, respectively. Consequently, the pressure losses proved to negate any obvious advantages to these configurations with OTP values of 0.98 for the 10,000 Reynolds number cases, 1.03 for the 25,000 Reynolds number cases, and 1.18 for the 40,000 Reynolds number cases.

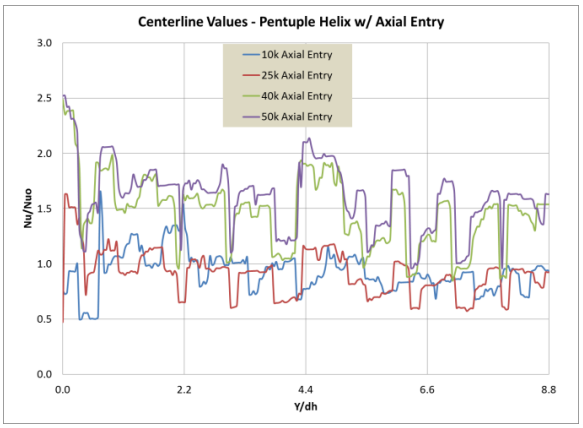

Figure 25. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Pentuple Helix with Axial Entry.

The centerline values shown in Figure 25 depict a relatively uniform trend of values for all Reynolds numbers, with the 40,000 and 50,000 Reynolds number test showing the best results in the pentuple helix test.

<u>Pentuple Helix – 90 Degree Inlet</u>

Except for the high localized heat transfer areas near the entrance to the channel, the 90 degree inlet test using the pentuple helix displayed similar results to that with the axial entry regime. As shown in Figure 26, the distribution of heat transfer was reasonably uniform when compared to the other two trip strip strategies.

The channel averaged heat transfer enhancement (Nu/Nu_o) values ranged from 1.17 for the Re = 10k test to 2.32 for the Re = 50k test. The Re = 25k test presented a value of 1.44 and the Re = 40k test a value of 1.96. When considering these values alone without the penalty of the pressure loss, they seem quite good at the higher Reynolds numbers. When the pressure losses are incorporated using Equation 7 the OTP values yield 1.20 for Re = 50k and 1.04 for Re = 40k. The lower Reynolds numbers came in with OTP values of 0.77 for Re = 10k and 0.75 for Re = 25k. This configuration would only benefit applications where pressure loss is not a primary consideration.

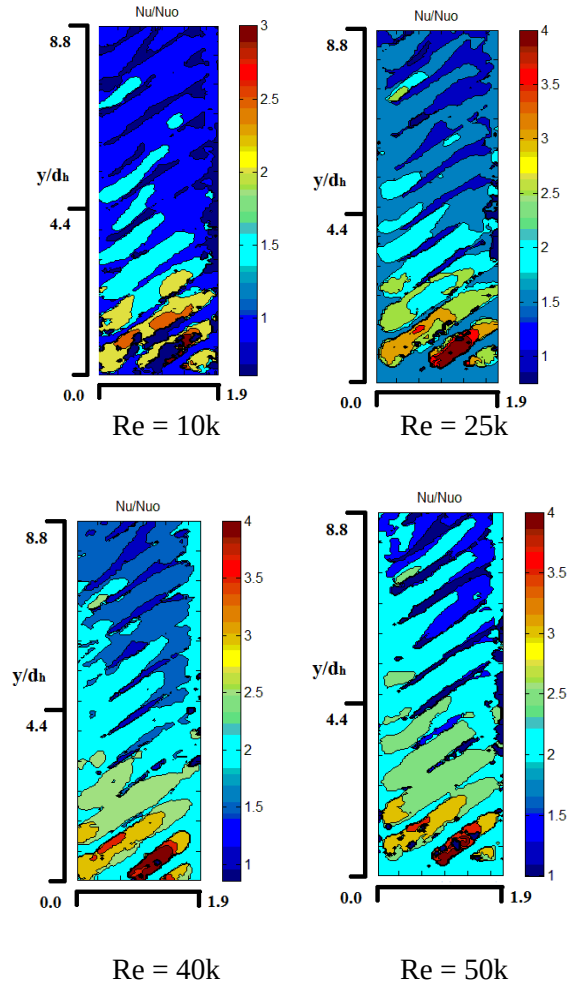

Figure 26. Heat Transfer Enhancement (Nu/Nu_o) for a Pentuple Helix with 90 Degree Entry at various Reynolds Numbers.

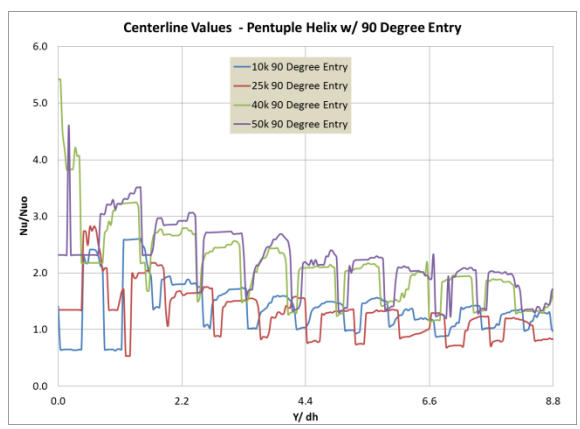

Figure 27. Line Plots of Centerline Values of Nu/Nu_o vs. Position along the Flow Path Axis for the Pentuple Helix with 90 Degree Entry.

Figure 27 is a centerline plot of Nu/Nu_o vs. position along the channel for all four Reynolds number tests. The wide flat lines of the peak values indicated that the entire area between the ribs is being utilized and there is very little "dead" area.

In order to better visualize the results of all three configurations as well as the two flow entry regimes a summary plot of all Nu/Nu_o values is shown in Figure 28. Note that when the data points are connected using a curve fit, a cyclical pattern appears to be present. The proof of this would require more testing at higher Reynolds numbers.

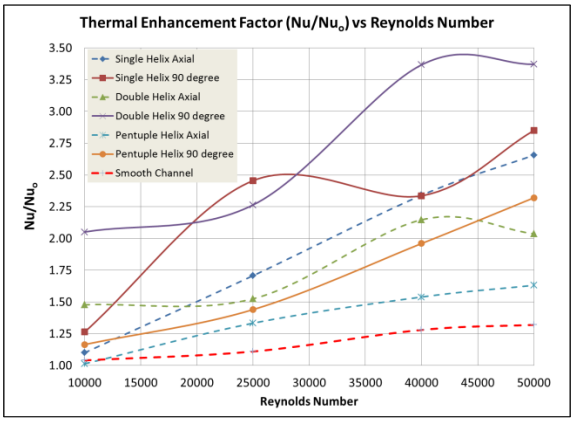

Figure 28. Thermal Enhancement Factor vs. Reynolds Number for all Seven Configurations Tested.

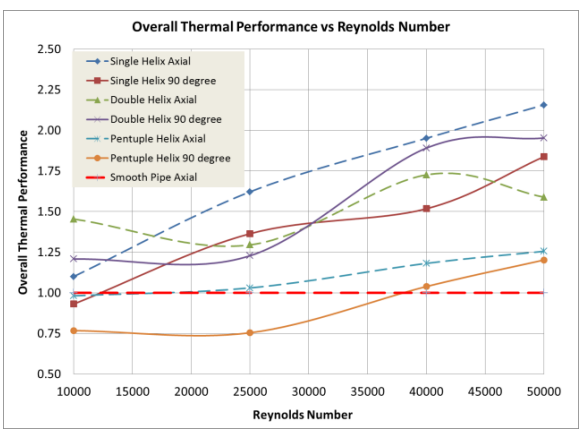

Figure 29. Overall Thermal Performance vs. Reynolds Number for all Seven Configurations Tested.

When pressure losses are considered the Nu/Nu_o values presented in Figure 28 can be used in Equation 7 to obtain OTP values. Figure 29 summarizes the OTP values verses Reynolds number for all three trip strip strategies and both entry flow regimes. When the data points are connected using a curve fit the same cyclical trends seem to form.

EXPERIMENTAL UNCERTAINTY AND ERROR

An accurate assessment of uncertainty in liquid crystal measurement of heat transfer coefficients is essential because many factors affect the TLC results. A large number of studies have concluded that a properly performed test yields mean uncertainty of up to 11.0% for values of h, and up to 9% for temperatures. Smith [4], et al, compiled a table summarizing uncertainty studies of h and T when narrow band TLC methods were used. Thermocouple accuracy and repeatability are large contributors to uncertainty as well as illumination spectral effects. The wall mounted thermocouples were used to compensate for this effect and resulted in a 0.2^o C temperature correction.

Some parameters that should be included in the uncertainty analysis include fluid density, fluid velocity, mass flow rate, material properties of the test piece, thermocouple accuracy, calibration of the TLC, and time.

The fluid density, fluid velocity, and mass flow rate uncertainties can be lumped together into the uncertainty in measuring the Reynolds number. The calibration of the TLC and the thermocouple accuracy can also be lumped into a category of "temperature". The uncertainty of the material properties and time are of less significance, but should not be ignored.

The overall relative uncertainty can be determined by using the Kline and McClintock method. Kline and McClintock [5] suggested the description of uncertainty by specifying the mean of the readings, along with an uncertainty interval based on certain predefined odds. Each variable should thus be reported as shown in the equation below:

$$U = [(u_1)^2 + (u_2)^2 + \ldots]^2 \qquad \text{(Eq. 8)}$$

Where:

U is the overall uncertainty

u is the uncertainty in the measured value (i.e. +/- 2 degrees)

Table 1 lists the items and uncertainty percentage used in the calculations of uncertainty in the experiments.

Variables	Uncertainty
Kinematic viscosity of air, μ	±2.9
Thermal conductivity of air, k_a	±3.0
Thermal conductivity of PC, k_t	±4.6
Thickness of liquid crystal, d_t	±3.5
Air mass flow rate, kg/s	±3.0
Liquid crystal temperature, TLC	±0.2
Air temperature, T_b	±3.0
Test Piece wall temperature, T_w	±2.5

Table 1. Variables used to determine experimental uncertainty.

It is not unusual to have uncertainty values in the range of 5% - 6% in TLC experiments. The overall uncertainty will depend on the accuracy of the equipment used and data obtained during the experiment.

A minimum of two of each tests was conducted to evaluate the repeatability of each test. Heat transfer values typically were repeatable within 3% for tests for Reynolds numbers of 10k and increased to 6% for Reynolds numbers of 50k. Estimates of the uncertainty in the Nusselt number parallel that of heat transfer coefficients.

CONCLUSION

There exists a substantial heat transfer benefit because of the opposing passages and 90 degree turn at the inlet of the slot shaped when compared to the axial entry and a smooth round pipe of equal hydraulic diameter. The pressure losses are upward of three times higher in the case of the higher Reynolds numbers tested. Despite these higher pressure losses, the enhancement gained by the high turbulence at the entry continued to aid the heat transfer in the entire channel and was enough to yield superior overall thermal performance values in the case of the double helix.

The test did not yield the same results for the single and pentuple helix configurations. The axial entry was better than the 90 degree entry for all Reynolds numbers tested with the single helix. The results with the pentuple helix were about the same for the axial entry and the 90 degree entry tests. The pentuple helix only performed about as well as the smooth channel when overall thermal performance values are compared. But, the pentuple helix exhibited a more uniform heat transfer distribution in the channel when used in conjunction with the 90 degree entry.

A plot of the data points seem to indicate cyclical trends are present in both Nu/Nu_o and OTP values that follow changes in Reynolds number.

ACKNOWLEDGEMENTS

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Optimal sequencing of a cooling tower with multiple cells

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ABSTRACT

This paper evaluates the energy savings potential of multi-cell cooling tower optimal sequencing control methods. Annual tower fan energy usage is calculated for a counter-flow tower with multiple variable-speed fans. Effectiveness-NTU tower model is employed to predict the cooling tower performance at various conditions. Natural convection when the fan is off is accounted by using an assumed airflow rate. The energy savings at five cities representing different typical climates are studied using typical meteorological year data. The results show that, if the tower capacity can be increased by 50% and 100% by running extra tower cells, the annual total fan power usage can be reduced by 44% and 61%, respectively. A cumulative saving percent curve is generated to help estimate the annual total savings percent when extra cooling tower capacity is available during only part of a year.

INTRODUCTION

Cooling towers are widely used in Heating Ventilating and Air-Conditioning (HVAC) filed and industrial sectors to dissipate waste heat from cooling water to atmospheric air. Induced-draft counter-flow evaporative cooling towers are one of the most popular tower types. Some towers are designed with multiple cells. Different cells are sequenced and fan speed is modulated to maintain the tower outlet cooling water temperature at the prescribed setpoint. Through the use of multi-cell cooling tower systems the cooling capacity can be flexibly designed to fit the process requirements and it guarantees a high availability of cooling capacities. For most of the year when it is at off-design conditions, cooling tower load is less than the capacity of the tower. Some towers are even designed with extra cells to provide spare capacity at design conditions. It is well known that running as more as possible tower capacities could save tower fan power. Although tower fans consumes a small portion of system total power, energy users should take advantage of every opportunity to reduce power requirements considering the present need to conserve energy. This paper targets on estimating the fan power energy savings by optimally sequencing multiple cells.

Cooling Tower Rating

The thermal capability of a cooling tower used for air conditioning is often rated as cooling 3 gallons per minute (gpm) (0.68 m^3/hr) of water from 95°F (35°C) to 85°F (29°C) at a 78°F (26°C) entering air wet-bulb temperature (one nominal ton corresponds to 15,000 But/hr [4.4 kW]). At nominal conditions, the range is 8°F to 10°F (4.4°C to 5.6°C) and the approach is 6°F to 8°F (3.3°C to 4.4°C). Typical values of airflow range from about 200 standard cubic feet per minute per ton (scfm/ton) (97 m^3/hr·kWt) to about 300 scfm/ton (145 m3/hr·kWt) [1, 2]. Towers designed for energy efficiency typically have small fans and large heat transfer surfaces. Towers designed for low initial cost usually have small heat transfer surfaces and large fans. Typical values of fan horsepower for induced draft towers range from about 0.04 hp/ton to about 0.08 hp/ton [3]. The condenser water flow rate is normally designed at 3.0 gpm per nominal ton (0.194 m^3/hr per nominal kW). For the same tower, the water flow rate can be as low as 1.5 gpm per ton (0.097 m^3/hr per kW), or as high as 6.0 gpm per ton (0.388 m^3/hr per kW), depending on the design of the water distribution system. If the water flow is too low, the distribution system will produce inadequate water coverage on the fill, which not only disrupts heat transfer efficiency, but also increase the work load of the fans. If the flow is too high, spray systems will be overpressurized or open hot water basins will be overflowed [4].

Cooling Tower Control

The tower capacity control can be fan cycling, two-speed fans, dampers modulating, and frequency-modulating controls. Compared to other controls, variable-frequency driven fans can save considerable

motor energy as well as extend the life of the motor, fan, and drive assembly. Although most variable speed drives (VSD) can modulate down to 10% or less of motor nominal speed, a 25% lower limit is recommended to maintain proper air and water distribution, especially in counterflow units [5]. To accomplish greater control of cold water temperature, and to avoid short cycling of single-speed motors, some towers are designed with by-pass systems to maintain acceptable water temperature to load. However, modulating by-pass systems are not recommended for towers operated during freezing weather. In such situations, the control flexibility afforded by multi-cell towers, and/or variable speed motors, should be considered [4].

A popular cooling tower leaving water temperature control strategy is to maintain a constant cooling tower approach temperature. This objective can be achieved by sequencing cooling cells and modulating fan speed. The strategies of sequencing cooling towers are various, but some general guidelines are summarized to improve the cooling tower performance.

Braun [6] and Nugent [7] have shown that, for variable-speed fans, the minimum power consumption results from operating all cooling tower cells under all conditions. The power consumption of the fans depends upon the cube of the fan speed. Thus, for the same total air flow, operating more cells in parallel allows for lower individual fan speeds and overall fan power consumption. For a multi-speed fan, when additional tower capacity is required, Braun and Klein et al. [6] showed that, in almost all practical cases, the speed of the tower fan operating at the lowest speed (including fans that are off) should be increased first. Near the optimum, the total power consumption is not very sensitive to the control but higher flow is preferred. They showed that the tower control that minimized the instantaneous power consumption of a cooling plant varied as a near-linear function of the load over a wide range of conditions. Although optimal control depended on the ambient wet-bulb temperature, this dependence was small compared to the effects of load.

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Cooling Tower Modeling

The mass and heat transfer process in a cooling tower is very complicated. The first practical theory of cooling tower operation was developed by Merkel [10] where there was counter-flow contact of water and air, and it has been the basis of most cooling tower analyses. In Merkel's analysis, the water loss due to evaporation was neglected and a Lewis number of unity was assumed. Merkel assumed that the bulk water in contact with a stream of air was surrounded by a film of saturated air and that the saturated air was surrounded by a bulk stream of air. The Number of Transfer Units (NTU) was expressed as a function of the integral of the temperature difference divided by the enthalpy gradient in a cooling tower. The determination of outlet states required an iterative numerical integration of two differential equations.

A more rigorous analysis without these assumptions was performed by Sutherland [11]. 5% to 15% undersize was found for counter-flow cooling tower with Merkel method. A simple, yet fundamental model for cooling coils was proposed by Threlkeld [12]. By assuming a linear relationship for saturation air enthalpy with respect to both surface and water coolant temperature conditions, Threlkeld obtained an analytic solution to the heat and mass transfer equations. Elmahdy [13] compared results of this model with experimental measurements for two different coil designs and found good agreement.

The effectiveness model is the most popular model in cooling tower simulations but iterations are required to obtain a converged solution. This method has advantages of simplicity, accuracy, quick speed, and consistency. An effectiveness model for cooling towers and cooling coils have been developed by Braun [14] utilizing the assumption of a linearized air saturation enthalpy. Water loss in the cooling tower is on the order of 1% to 4% to entering water flow and

neglecting this loss may result in up to a 2ºC (3.6ºF) error in the exit water temperature. A simple method for estimating the water loss was development. The root mean square deviation of the model was approximately 1.4ºF (0.8ºC). Overall, the effectiveness model appeared to give satisfactory results for temperature differences up to 50°F (28 ºC) between the water inlet and ambient wet-bulb. An assumed Lewis number of about 0.9 rather than unity was recommended. The advantages of this approach are its simplicity, accuracy and consistency. The accuracy of the effectiveness model is as good (or better) as that associated with standard methods while requiring significantly less computational effort. This model has been used by Jiang [15], Flake [16], and Yu [17] to study the plant optimization. But the input variable of air flow rate is replaced with cooling tower leaving setpoint to match the real control logic. The fan power is calculated from fan law with 10% minimum flow rate.

Shelton and Weber [18] report a correlation of fan break horsepower to the air flow rate raised to the 3.2 power. Bradford [19] found that the tower fan demand is calculated from a relationship of power to airflow. Experiment data showed that the cooling tower fan power followed the cubic fan law closely because the air system friction characteristics did not change much. Considering that the pressure-flow characteristic is fixed for cooling tower, Lu et al. [20] modeled the fan power with three-order multiple as a function of air flow ratio.

Study Objective

This study provides a quantitive study on the energy savings potential estimation of fully utilizing the cooling capacities of multi-cell towers equipped with VSDs. An effectiveness-NTU tower model is adopted to predict the cooling tower performance at various conditions. Natural convection when the fan is off is accounted by using an assumed airflow rate. The energy savings at five cities representing different typical climates are studied using typical meteorological year data. The tower leaving water temperature is maintained between upper and lower limits with a constant approach setpoint. The conclusion can be used to quickly estimate the economic feasibility of such retro-commissioning projects on cooling tower fan optimal sequencing.

METHOD

The efficentivnee-NTU model is introduced as follows [14]. For a counter-flow wet cooling tower, the cooling tower effectiveness (ε) is defined as the ratio of the actual energy transfer to the maximum possible energy transfer:

$$\varepsilon = \frac{h_o - h_i}{h_{swi} - h_i} \qquad \text{Equation (1)}$$

In Equation (1), h_i and h_o are the enthalpies of the air into and out of the tower, and h_{swi} is the enthalpy of air saturated with water at the inlet water temperature. Effectiveness is a dimensionless variable which can be determined from m* and NTU.

$$m^* = \frac{m_a C_s}{m_w c_{pw}} \qquad \text{Equation (2)}$$

$$C_s = \frac{(h_{swi} - h_{swo})}{(T_{wi} - T_{wo})} \qquad \text{Equation (3)}$$

Where, m_a is the air mass flow, m_w is the water mass flow, C_s is the effective specific heat of moist air, c_{pw} is the specific heat of water, T_{wi} is the inlet water temperature, and T_{wo} is the oulet water temperature. The NTU of the tower is correlated by [21]:

$$NTU = c\left(\frac{m_w}{m_a}\right)^n \qquad \text{Equation (4)}$$

Typical values of coefficient n are in the range $0.4 < n < 0.6$ [21]. If a typical value of n is assumed, the value of c can be determined from air mass flow rate (m_a) and water mass flow rate (m_w) at nominal design conditions. Once c and n are known for a particular cooling tower, the cooling tower performance can be predicted at any operating condition given the water inlet temperature, the ambient air wet-bulb temperature, and the air and water flow rates.

For a counter-flow cooling tower,

$$\varepsilon = \frac{\left(1 - \exp\left[NTU\left(m^* - 1\right)\right]\right)}{\left(1 - m^* \exp\left[NTU\left(m^* - 1\right)\right]\right)} \qquad \text{Equation (5)}$$

The leaving water temperature and flow rate can be determined from an energy and mass balance. When the fan is off, a constant volumetric air flow due to natural convection is estimated.

This model is utilized in this study to simulate the system to produce leaving cooling water at the prescribed setpoint. A feedback controller is designed to seek the desired fan speed. The fan power can be calculated using a second-order polynomial model.

APPLICATION

Example System

This study is based on an imaginary cooling tower with four identical cells serving a 5200-ton (18,288 kW_t) centrifugal chiller. Table 1 shows the rated conditions of the system.

The Typical Meteorological Year 3 (TMY3) hourly weather data [22] are used to generate bin weather data based on the dry-bulb temperature. The chiller cooling load is regressed as a function of ambient wet-bulb temperature:

$$Q_{chlr} = c_0 + c_1 T_{wb} + c_2 T_{wb}^{\ 2} \quad \text{Equation (6)}$$

Table 1: System input parameters

Chiller design capacity	5200	Ton
Chiller chilled water entering temperature	60	°F
Chiller chilled water leaving temperature	42	°F
Cooling tower coefficient c	3.5	
Cooling tower coefficient n	0.4	
Cooling tower water flow rate	13,000	GPM
Total number of cells	4	
Maximum airflow per cell	600,000	cfm
Fan power at maximum airflow	156	hp
Natural convection airflow	70,000	cfm
Fan minimum speed ratio	0.25	
Tower max water leaving temperature	85	°F
Tower min water leaving temperature	60	°F
Cooling tower approach setpoint	7	°F
Chiller load coefficient c_0	2731.23	
Chiller load coefficient c_1	19.2837	
Chiller load coefficient c_2	0.1618	
Cooling tower fan power coefficient d_1	0.1643	
Cooling tower fan power coefficient d_2	-0.0574	
Cooling tower fan power coefficient d_3	0.9657	

The power of the VFD-equipped cooling tower fan can be calculated with a model regressed from the trended fan speed ratio (r_f) and fan motor power:

$$\frac{P_{fan}}{P_{fan,rated}} = d_1 r_f + d_2 r_f^{\ 2} + d_3 r_f^{\ 3} \quad \text{Equation (7)}$$

Figure 1 compares several fan power ratio curves as a function of fan speed ratio: the proposed one, the one based on fan law, and the one used by Kreider [23]. The condenser water flow is maintained at 2.5 gpm per rated ton or 13,000 gpm (2953 m^3/hr). The rated fan air flow is 600,000 cubic per minute (cfm) (283 m^3/s) and the natural convection when the fan is off is 70,000 cfm (33 m^3/s). The fan minimum speed is 0.25. The tower leaving air temperature is no higher than 85°F (29°C) and no lower than 60°F (16°C) with a constant approach setpoint of 7°F (3.9°C). The coefficients for the chiller load curve and the fan power curve are also listed in Table 1.

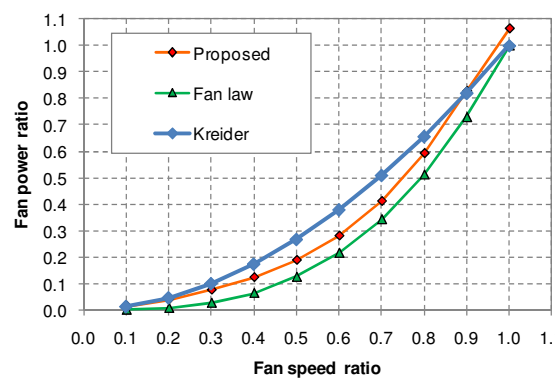

Figure 1 Fan power curves as a function of fan speed ratio

Simulations and results

Three operating scenarios are defined: two cells, three cells, and four cells all year round. The system is designed to run two cells but it can also run three or four cells simultaneously. The cooling water will be equally distributed to all cells staged on.

The fan speed in each dry-bulb bin and the corresponding fan power are simulated using the effectiveness-NTU model. When the hour number in each bin is taken into account, the annual fan power for each scenario is calculated. As the condenser water flow rate is unchanged and the pump head change is neglected, the pump powers for all scenarios are identical. So does the chiller power as the chiller condenser water entering temperatures and chiller loads are identical for all scenarios.

Figure 2 shows the simulated tower leaving water temperature profiles as well as the setpoint profiles. A perfect match can be observed. Figure 3 presents the simulated fan speed in each bin for all operating scenarios. The fan runs fastest when the wet bulb temperature is around 54°F (12.2°C). For four-cell scenario, the fan will stop when the wet-bulb temperature is lower than 36°F (2.2°C). This occurs at 29°F (-1.7°C) for three-cell scenario and 18°F (-7.8°C) for two-cell scenario. Part of warm cooling water will be by-passed into the basin to ensure the leaving cooling water temperature no lower than 60°F (16°C).

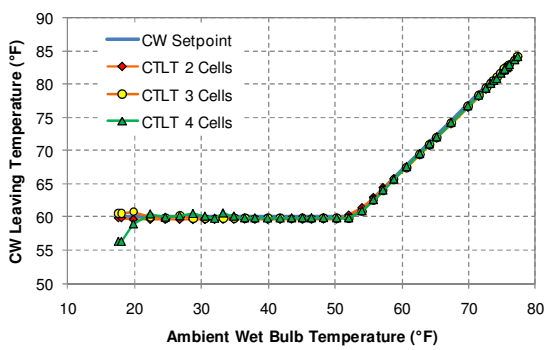

Figure 2. Simulated tower leaving water temperature profiles

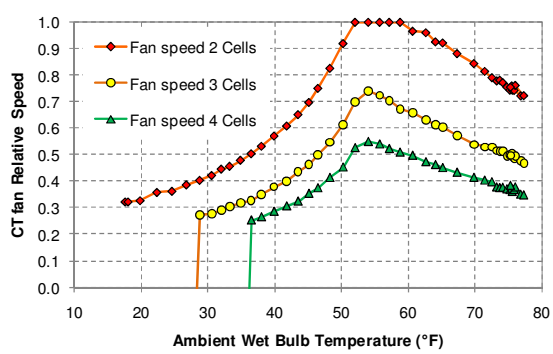

Figure 3. Simulated tower fan speed percent profiles

In Figure 4, the fan power usage profile for each scenario is shown. Majority of fan power savings are achieved when the wet-bulb temperature is between 50°F (10°C) and 70°F (21°C) when the baseline fan speed is high. Compared to the baseline (two-cell scenario), the annual fan power usage drops to 55% of the baseline for three-cell scenario and to 38% for four-cell scenario. As reducing water flow through the tower increases the probability of freeze-up during winter operation, it is reasonable to eliminate such operations as the savings is neglectable when the ambient wet-bulb temperature is less than 45°F (7.2°C).

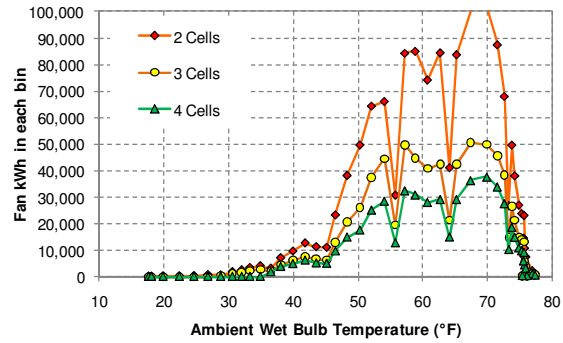

Figure 4. Simulated fan energy profiles

Similar simulation and analysis are applied to other five cities representing different typical weathers and similar results are obtained except for Denver. The possible explain is due to its lower than normal atmosphere pressure. The average fan power saving percent is 44% for three-cell scenario and is 61% for three-cell scenario. Table 2 details the results.

Table 2: System input parameters

	Houston	Chicago	Miami	Phoenix	Denver	Los angles	Average
2 cells	100%	100%	100%	100%	100%	100%	100%
3 cells	55%	55%	56%	56%	60%	53%	56%
4 cells	38%	36%	39%	38%	45%	37%	39%

The factors that are possible to affect the savings percent include cooling tower type, chiller load profile, and condenser water flow rate. Several testing runs are performed and there is no significant change on the savings percent for three-cell running and four-cell running. This means the average savings percents presented above could be a general value.

In practice, due to various reasons, it may not be possible to increase the cooling tower capacity all year round. Figure 5 shows the cumulative fan power saving percent versus normalized ambient wet-bulb temperature. For Houston, the lines for the three-cell scenario and three-cell scenario overlap each other. However, it is obviously different from the curve for Phoenix. This curve can be used to estimate the annual savings if the spare cooling tower capacity is available during only part of a year. For example, it is assumed that, the cooling tower capacity can be increased by 50% when the normalized wet-bulb temperature is lower than 0.8 and by 100% when the

normalized wet-bulb temperature is lower than 0.6. The corresponding cumulative fan power saving percent is 0.58 and 0.20, respectively. The annual fan power saving percent can be estimated as:

$$\text{Saving } \% = 0.20 \times 61\% + (0.58\text{-}0.2) \times 44\% = 28.9\%$$

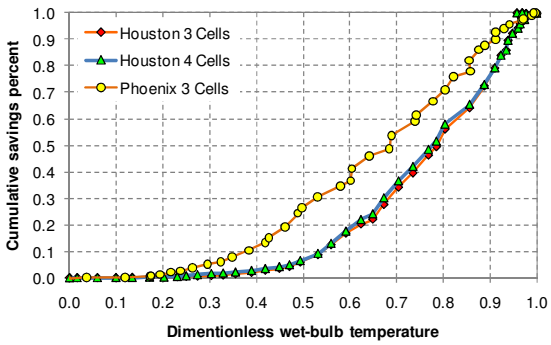

Figure 5. Cumulative savings percent profiles

SUMMARY AND CONCLUSION

It is well known that, for variable-speed fans, the minimum power consumption results from operating all cooling tower cells under all conditions. However, there is no quantitative study on the fan power savings potential in previous researches. This paper utilized the effectiveness-NTU cooling tower model and an imaginary cooling system to study the fan power savings potential. Simulation results show that, if the cooling tower capacity is increased by 50% and 100%, the annual fan power usage can be reduced by 44% and 61%. A cumulative saving percent profile is generated to estimate the annual total savings when extra cooling tower capacity is available during only part of a year.

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Heat Integration and Heat Recovery at a Large Chemical Manufacturing Site

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ABSTRACT

The Honeywell chemical plant located in Hopewell, Virginia includes processing units that purify raw phenol, react the phenol with hydrogen to form crude cyclohexanone, and purify the crude cyclohexanone. In order to reduce energy usage, two opportunities for heat recovery and heat integration were identified. A feasibility study and economic analysis were performed on the two opportunities, and both projects were implemented.

The first project utilized the heat contained in a distillation process overheads stream to preheat the raw material entering the distillation process. This was accomplished via a heat exchanger, and reduced the utility steam requirement by 10,000 pph.

The second project utilized the heat generated by the hydrogenation reaction (in the form of waste heat steam) to preheat the feed material in an adjacent process. This was accomplished via a heat exchanger, and reduced the utility steam requirement by 8,000 pph.

These two energy projects required $1.1 million of capital and saved $1.0 million in utility steam annually.

INTRODUCTION

The Honeywell chemical plant located in Hopewell, Virginia is the world's largest single-site producer of caprolactam and ammonium sulfate. Caprolactam is the primary raw material used in the production of nylon. Ammonium sulfate is utilized mainly as a fertilizer.

One of the operating units that supports the manufacture of caprolactam is the phenol hydrogenation area. This area contains processes that purify raw phenol, react the phenol with hydrogen to form crude cyclohexanone, and purify the crude cyclohexanone. The purified cyclohexanone is a component used to produce caprolactam.

The chemical plant is energy intensive, utilizing approximately 700,000 pph of steam for various heating needs. Opportunities for reducing the utility steam requirements are sought and evaluated on a regular basis. Two such opportunities, both heat integration and recovery opportunities, were identified, evaluated for feasibility, designed, and implemented.

Implementation of these two projects required $1.1 million in capital investment. The utility steam requirement of the site was reduced by 18,000 pph, saving the company $1.0 million per year.

Figure 1. Honeywell Hopewell Plant

PROCESS DESCRIPTION

The phenol hydrogenation area contains processes that purify raw phenol, react the phenol with hydrogen to form crude cyclohexanone, and purify the crude cyclohexanone.

The raw phenol delivered to the chemical plant contains undesirable impurities that must be removed prior to its use to make cyclohexanone. An additive is applied to the raw phenol which reacts with the impurities, forming compounds that can be removed via a distillation process. The distillation bottoms contain the separated impurities. The distillation overheads contain the purified phenol, which is utilized in the hydrogenation process.

The hydrogenation process uses a catalyst to react the purified phenol with hydrogen, forming a mixture of cyclohexanone and cyclohexanol. The reaction is exothermic and is cooled with water to control the rate of reaction, while maximizing the production of cyclohexanone. The heated water is circulated to a flash drum where it is cooled by flashing off 6 psig "waste heat" steam. The cooled water is then re-circulated back to the reactor.

The mixture of cyclohexanone and cyclohexanol exits the reactor and is separated in a distillation process. Purified cyclohexanone is routed to the caprolactam process, and the cyclohexanol is sold to external customers.

The heat integration and heat recovery opportunities were identified in the phenol purification process and the hydrogenation process.

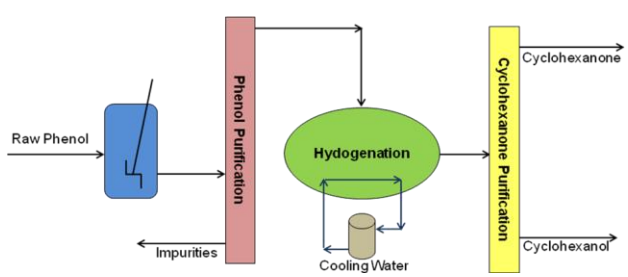

Figure 2. Phenol Hydrogenation Process

ENERGY REDUCTION OPPORTUNITIES

Process heat integration and process heat recovery opportunities were identified in the phenol hydrogenation area.

Process Heat Integration

The process heat integration opportunity was identified in the phenol purification process. Utility steam is supplied to provide heat to a distillation process that separates impurities from the raw phenol supplied to the process. Approximately 35,000 pph of utility steam is required for this purpose.

The project proposed that the heat available in the distillation column overheads stream be used to preheat the raw phenol feed stream to the column. In doing so, the overall utility steam requirement would be reduced. The heat integration of the two process streams was achieved using a plate and frame heat exchanger.

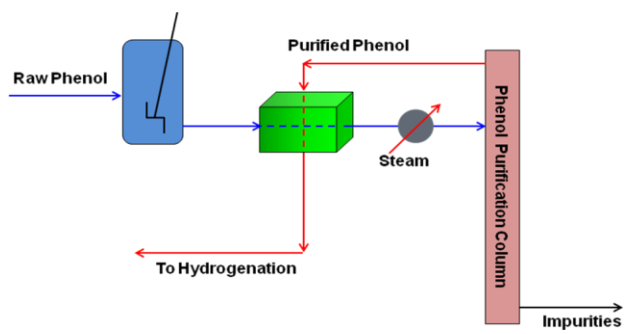

Figure 3. Process Heat Integration

Process Heat Recovery

The process heat recovery opportunity was identified in the hydrogenation process. The hydrogenation process contains an exothermic reaction which is cooled with water to control the rate of reaction. The heated water is circulated to a flash drum, where it is cooled by flashing off 6 psig "waste-heat" steam. Prior to implementation of this project, the flashed steam was vented to the atmosphere.

The project proposed that the vented 6 psig steam be recovered and utilized to displace utility steam in a heating application. There were no viable heating applications in the phenol hydrogenation area, so other heating applications were sought in adjacent process areas.

Process Heat Recovery (continued)

A viable heating application was identified in the adjacent caprolactam process area. There, a distillation column was using utility steam as its heat source. It was proposed that the 6 psig "waste-heat" steam be routed to a new preheater to heat the process stream fed to the distillation column, thereby displacing a portion of its utility steam requirement.

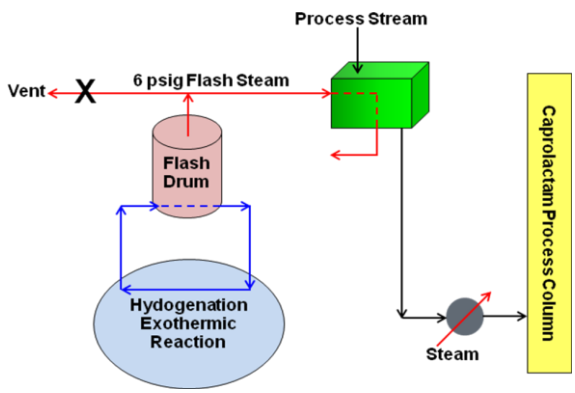

Figure 4. Process Waste Heat Recovery

RESULTS

The process heat integration and process heat recovery projects reduced the utility steam demand of the plant site by 18,000 pph. The reduction in utility steam saved the site $1.0 million per year.

Process Heat Integration Benefits

Upon placing the new plate and frame heat exchanger in service, an immediate reduction in the utility steam requirement was realized. The utility steam requirement was reduced by 10,000 pph, a savings of $550,000 per year. The cost of installing the plate and frame heat exchanger was $550,000.

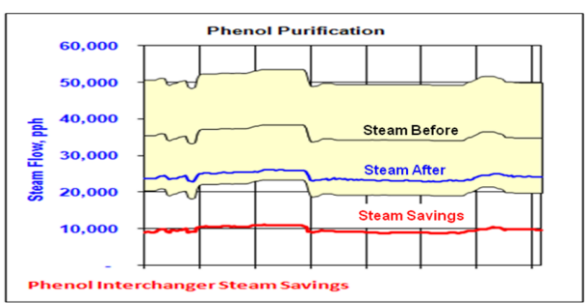

Figure 5. Steam Reduced from Heat Integration

Process Heat Recovery Benefits

Upon placing the new preheater in service, the amount of vented, 6 psig "waste-heat" steam became zero. An immediate reduction in the utility steam requirement was realized. The utility steam requirement was reduced by 8,000 pph, a savings of $450,000 per year. The cost of installing the new preheater was $550,000.

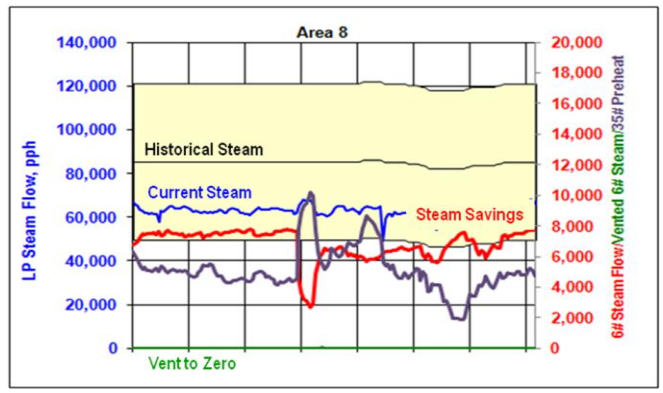

Figure 6. Steam Reduced from Heat Recovery

CONCLUSIONS

Implementation of heat integration and heat recovery projects as retrofits to existing plant processes is challenging. Often, these types of projects are better suited to be incorporated into the original design of a plant.

When attempting to retrofit existing processes with heat integration and heat recovery installations, the challenges include, material compatibility, energy balancing, space limitations, geography, and the capital costs associated with those items.

In the case of the Honeywell chemical plant in Hopewell, Virginia, two significant energy savings opportunities were identified. After thorough evaluation and design, the two projects were installed and implemented. Upon implementation, the projects yielded significant savings and excellent returns on the capital investments.

Development of a Software System to Facilitate Implementation of Coal and Wood Co-Fired Boilers

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ABSTRACT

Coal and wood co-fired boiler technology has improved significantly over the years. The term "co-firing", when used by members of the biomass or utility communities, has come to mean mixing a modest amount of clean, dry sawdust with coal and burning the sawdust coal mixture in a large, coal-burning, utility boiler. This paper discusses the development of a computer software system that interacts with the user and allows coal-wood co-fired boilers to be sized, priced, implemented, and operated properly. Information about the equipment that is required for the boiler replacement project is provided. Along with these features, the software would allow the user to determine energy and cost savings that would be available upon installation as compared to other types of boilers. The paper outlines how these savings are realized, and the steps that must be taken to ensure the proper operation of the boiler to achieve these savings. A sensitivity analysis has also been performed on the implementation of coal-wood co-fired boilers in order to determine the key factors influencing the project payback period. The key factors that are considered in the analysis are the boiler size, the annual operating hours, and the current fuel cost. Additional analysis has been done on the boiler size and the annual operating hours. This analysis allows the users to determine if their current facility falls into the feasible range for implementing a coal-wood co-fired boiler system.

INTRODUCTION

Coal and wood co-fired boiler technology is most likely to benefit the industrial sector and contribute towards energy and cost savings. The high price of many traditional fuels such as natural gas and electricity is a concern to most manufacturing facilities in terms of controlling their operating costs. Because these fuels are in high demand, the cost continues to rise with the increasing demand. With increasing use, the supply of these types of fuels will keep on reducing and the cost will continue to rise. Currently, on account of a large demand for coal and wood fuels, and due to the fact that it does not seem that these fuels will ever be a dominate energy source, the cost for these fuels as compared to traditional fuels is much lower.

The industry sector should be informed of alternative fuel capabilities, as it continues to deplete the current fuel supplies at increasing rates. The system developed and reported in this paper along with the associated software will help to initialize the interest in utilizing alternative fuels in boilers. Any new technology and technique that can be developed to utilize alternative fuel sources and lessen the load on traditional fuels will benefit the economy and environment worldwide. Prior to understanding the functions and capabilities of wood-coal co-fired boilers, it is essential to discuss the background information on these boilers.

The research objectives are to develop a model to assist in evaluation and implementation of coal-wood co-fired boilers, synthesize information to enable coal-wood co-fired boiler use, and determine the most desirable conditions for coal-wood co-fired boiler implementation.

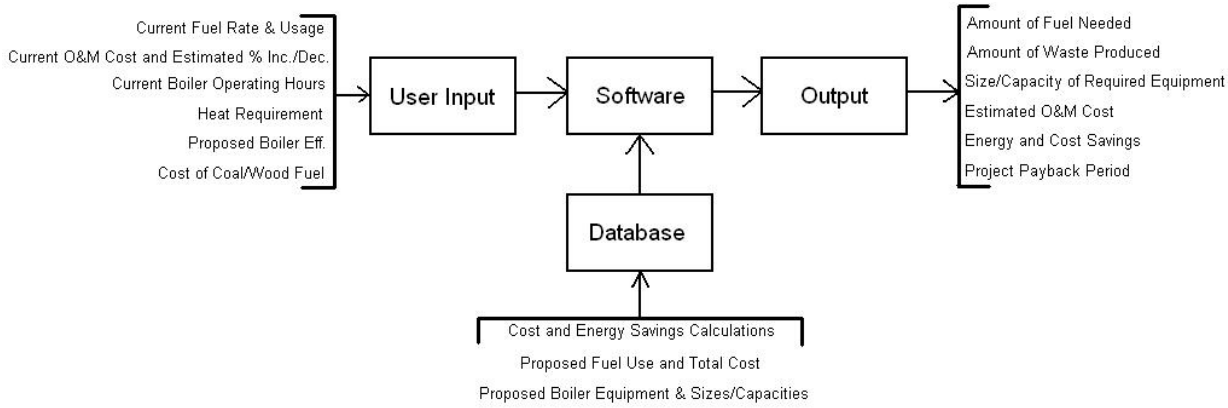

Figure 1: System Diagram

The system diagram which outlines the proposed computer software is shown in Figure 1.

Coal-Wood Co-Fired Boilers

Coal-wood fired boilers allow for the use of waste wood such as sawdust, wood pellets, and other types of waste wood that would otherwise be disposed of in a non-efficient manner. The wood must be converted into sawdust before being used in the co-firing process. Implementation of alternative fuel burning boilers in a given facility is not a complex task. The feed and storage systems for alternative fuel sources can be implemented at a reasonable cost. Other than these storage systems, the boiler setup is quite similar to any other traditional boiler configuration. Companies can sometimes be discouraged by the thought of implementing a boiler system burning alternative fuels. The system developed and reported in this paper, along with the software details, is likely to help and encourage the use of alternative fuels in boilers. There are a number of different equipment options and configurations for implementing a coal-wood co-fired boiler system and this paper will examine the details of installing and implementing these systems in industrial facilities.

Coal-wood co-fired boilers are considered as “solid-fuel” fired boilers. This includes coal and wood as well as many other biomass fuels. Biomass, in terms of the energy production industry, refers to living and recently living biological material which can be used as fuel. Most commonly, biomass refers to plant matter grown for use as bio-fuel, but also includes plant or animal matter used for production of fibers, chemicals or heat. Biomass may also include biodegradable wastes that can be burnt as fuel. It excludes organic material which has been transformed by geological processes into substances such as coal or petroleum. It is usually measured by dry weight. Biomass can originate from several plants, including switch grass, hemp, corn, willow and sugarcane. This study will focus primarily on coal and wood co-fired boiler applications.

The present boiler systems are classified based on the size and capacity. This study will consider coal-wood co-fired boilers in the range of 15 HP to 800 HP (147.02 kW to 7,841.5 kW or ~0.147 MJ/s to ~7.841 MJ/s) since most boilers used in industry fall within this range. Typical coal-wood co-fired boilers do not react very quickly to drastic changes in steam demand. Therefore, these types of boilers are more suitable for applications that are under steady load conditions. The capacity and needs of various industrial facilities will influence the size of boiler and support system equipment. Boilers differ in size and in their designs and are primarily categorized as water-tube and fire-tube types [1].

Most coal-wood boilers burn sawdust along with different grades of pulverized coal. The grade of the coal is determined by the composition of the coal, which can be made up of a combination of several different elements. If a coal pulverizing system is required on site, the capacity of the pulverizer can be estimated. If the wood fuel is to be mixed in with the coal in the pulverizer, only wood in the form of sawdust

can be inserted into the pulverizer. Costs of wood grinder should be considered if wood fuel is not readily available in dust form. The coal is fed into the machine and crushed into a dust form of fuel. The wood dust can also be added to the coal in the pulverizer as long as it is in the dust form and does not cause any clogging.

The moisture content of the wood sawdust to be burned with the pulverized coal must be less than 20% by weight. If wood dust is not readily available, a grinder can be utilized to convert solid wood to wood dust on site. The blends are typically about 3% wood and 97% coal. The moisture content of the mixture becomes important when emissions are considered. Reduction in the moisture content of the fuel mixture results in lesser emissions. The wood can either be fed to the coal pulverizer to be mixed or there can be separate feeding systems for the wood and the coal. Boilers can be manually fed or elaborate feeding systems can be used in order to automatically feed the furnace [2].

In some cases, the wood that is to be used as a fuel may be above the recommended moisture content level of 20%. In this case, a system could be set up to use the boiler exhaust heat to preheat the wood fuel in order to bring the moisture content to a level below 20%. Coal-wood fuel storage bins are used that can store the fuel for extended periods. This can depend on the type and location of the facility as it is not always practical to have large amounts of fuel on hand. Problems such as freezing and spontaneous combustion can arise. Therefore, most facilities do not keep more than a few days' worth of fuel supply in the storage bins. A common method of fuel storage and feed involves various sized storage bins which use a walking floor feed system to feed the fuel along the bottom of the bin to a metered screw feed system which then transports the fuel directly to the boiler.

A metered screw has a rotating auger mechanism that feeds the coal-wood fuel down a chamber and into the furnace. The blades of the screw carry the coal-wood fuel in metered amounts so the furnace is being constantly fed with the proper fuel supply. The walking floor feeding system has a number of blades that continuously move the fuel in controlled amounts along the bottom of the fuel storage bin. A walking floor feeding system can also be implemented. In both cases, the rate at which the fuel is fed can be adjusted.

Coal-wood co-fired boilers are equipped with a metered screw auger at the bottom of the firing chamber of the boiler. The auger operates continuously to move ash out of the chamber. The ash is then transported to a disposal receptacle located adjacent to the boiler. A combination of conveyors and the screw augers can be used for effective ash removal. The exhaust gas from the boiler will contain ash and dust from the furnace and must be removed effectively. The most efficient methods of dust and ash removal from the exhaust gas must be used to meet environmental protection standards. Electrostatic precipitators offer a good solution for dust removal. There are a number of methods, techniques, and pieces of equipment available for the removal of dust, ash, and harmful NOx and SOx emissions. Primary emissions control technologies that exist in industry today are low-NOx burners (LNB) and over-fire air (OFA) which is also referred to as air staging. A control system could be used in conjunction with these technologies for effectively controlling NOx emissions.

Re-burning is another type of emissions control technology. Using re-burning techniques, up to 25% of the total fuel heat input is provided by injecting a secondary fuel above the main combustion zone to produce a slightly fuel-rich re-burn zone with a stoichiometry of ~90% theoretical air. Combustion of re-burning fuel at fuel-rich conditions results in hydrocarbon fragments, which react with a portion of incoming NOx to form hydrogen cyanide, isocyanic acid, isocyanate, and other nitrogen-containing species. These species are ultimately reduced to N_2. Finally, completion air is added above the re-burn zone to complete burnout of re-burning fuel [3].

LITERATURE REVIEW

Some work has been reported in the literature on the topic of coal-wood co-fired boilers but only a few publications exists in terms of modeling a system to facilitate the implementation of coal and wood fired boilers at specific facilities. Most of the work done in this

field is related to emissions and environmental compliance, coal-wood co-fired boiler process control, reducing corrosion in boilers, and co-combustions with other solid fuels. There does not seem to be any model that would assist in sizing a boiler and other equipment required to cater to specific industrial facilities.

One area of research reported in the literature is in improved process control of industrial coal-wood burning boilers. Reports and research in this area focus on the feasibility of improved process control methods for coal-wood co-fired water tube boilers. Process control can be quite challenging due to the fact that the nature of the fuel is highly variable [4]. Along with the fuel being variable, the boiler designs necessary to burn certain types of fuel vary as well. Frequent load swings required to meet changing process demands also add to the variability of the steam generation process. To stabilize the operations and to reduce vulnerability to coal-wood fuel variations, it has become common to add fossil fuels such as oil or natural gas and also to pump air into the furnace at excessive levels to increase combustion efficiency. Air pumped into the combustion zone to increase combustion efficiency as well as decrease emissions is rarely used at the optimal condition [5]. Models have been constructed to attempt to determine more effective methods for process control by developing robust controllers. The controllers that are proposed have the objective of increasing the responsiveness to load changes, reducing the variability of controlled parameters, and improving efficiency of the boiler by reducing fuel consumption [6].

Co-firing wood and coal together in boilers has been a major area of research in the boiler industry. Studies and experiments are still being performed to track the performance of coal and wood mixtures and the emissions that result from burning. Co-firing of wood with coal is thought by some to be one of the best methods of utilizing wood as a biomass fuel [7].

Tests on co-pulverizing and co-firing have been conducted to explore the possibility of fueling a boiler with a coal-wood mixture. The wood was pulverized for the experiments by feeding it into a vertical spindle type mill at up to 3% by weight together with coal. The tests were successfully performed with an increase of power consumption of the mill. Combustion tests were conducted with the pulverized fuel obtained, which resulted in good combustion efficiency and low NOx emission. A result of these tests show that co-firing with wood biomass by a small percent in pulverized coal fired boilers is possible with minimum installation of new equipment [7].

An important field of study related to wood fired boilers is in the area of NOx, or nitrogen oxides emissions. Factors examined in reports included fuel nitrogen content, total heat input, percentage boiler heat input from waste water treatment plant residuals and fossil fuels, boiler exit or stack oxygen content, and stack carbon monoxide content. A number of wood burning boilers were analyzed using NOx emission monitors. Using only the data collected on days when wood heat input represented 90% or more of the total daily boiler heat input, the results showed that NOx emissions showed no relationship to either total boiler heat input or boiler exit O_2 concentrations [8].

A major field of research is corrosion, mainly in super heaters, in wood fired boilers. One of the major drawbacks to the combustion of 100% biomass in boilers is the increase in the fouling and corrosion of super heaters. Studies have shown that typical superheated steels in boilers using 100% wood fuel and having steam temperature higher than 480°C (~896°F) do not last much longer than 20,000 hours, or about four operating years before they must be replaced [9]. Most of the studies and reports focus on improving already existing wood fired boiler designs. There does not seem to be much research conducted on developing a standard system model for installing a new wood fired boiler system, or for calculating and projecting potential energy savings. More research and development in this area could greatly serve industry by increasing interest in wood and biomass fuel energy.

RESEARCH APPROACH & SOFTWARE DEVELOPMENT

The overall objective of this project is to develop a software system that will assist in sizing, pricing, and implementing coal-wood co-fired boilers at industrial facilities. The software

includes cost estimations for current fuel sources as well as projected costs for wood and coal fuel. Though estimates for fuel costs are provided in the software, the user may override these values if they are known. This will result in more accurate results. Energy cost savings result from the use of the coal-wood fuel mixture as compared to the current fuel being used. The software also considers other costs associated with implementing a coal-wood co-fired boiler including boiler cost, fuel storage and handling equipment cost, other various pieces of equipment costs, and increased operation and maintenance cost.

Software Development Details

The software allows the user to enter their current boiler fuel usage and fuel cost rate. This allows for accurate energy savings calculations that pertain specifically to the facility being analyzed. The fuel types that will be considered for current costs are #2 Fuel Oil, #6 Fuel Oil, Kerosene, Propane, Natural Gas, and Electricity. The energy cost savings between the current and proposed fuel types are generated by the software using the user input and values within the software database.

The software allows the user to enter boiler and facility parameters including annual operation and maintenance cost, annual hours of operation for the boiler, number of weeks per year for boiler operation, and boiler heat requirement. These values provide the parameters required to determine the amount of energy cost savings that can be achieved by installing a coal-wood co-fired boiler. The number of weeks of operation per year allows the program to determine how much fuel supply is required to facilitate one week of boiler operation.

The software allows the user to enter the estimated percent increase or decrease in the current operation and maintenance costs for the boiler system. This will help in determining the project payback period. The software user can enter the cost of each piece of equipment specific to their facility. When a cost estimate is obtained from a manufacturer, this cost can be entered into the program to estimate the simple payback period more accurately. Allowing the user to enter the cost of each equipment allows for the customization of the program to fit the user's needs specifically. If a certain piece of equipment is not required, the cost will not be included in the economic analysis.

The software is capable of producing output on the accurate estimate of the capacity and size of the boiler design and equipment, the expected annual energy savings, and the estimated costs of fuel, operation, and maintenance. The software is named as "Coal-Wood Co-Fired Boiler Feasibility Program." The software was developed using the Microsoft Excel® program. The goal of the software was to be as user friendly as possible, while maintaining a high degree of detail and accuracy.

The first set of parameters to be entered into the software by the user is related to the current boiler annual fuel usage. The input and output cells are highlighted to classify them properly. This makes it easy for the user to understand which cells are for input. A pull down menu option is utilized so the user can choose which type of fuel the current boiler is utilizing. The function of the pull down menu is to set the units for the user to enter their annual boiler fuel usage. All of the units are in MMBtu/yr (=1,055.05 MJ/yr) except the case of an electric boiler, in which the units would be converted to kWh/yr as determined by the pull down menu. The user is then able to enter their current fuel cost.

Other boiler parameters included in the user input section for the current boiler include annual operation and maintenance cost, annual boiler operating hours, the number of weeks per year the boiler is in operation, and the boiler heat requirement. The boiler heat requirement allows for the software to determine the amount of fuel needed to meet this requirement using the coal-wood co-fired boiler. The average efficiency of most coal-wood co-fired boilers is approximately 80%. This value is entered into the software initially, but is easily over-ridden by the user if they know the actual efficiency of the new coal-wood co-fired boiler to be installed. The efficiency and the heat requirement allow the software to calculate the MMBtu/hr (kW) of fuel necessary to operate the boiler. Using the annual hours of boiler operation, the software can determine the annual

amount of coal-wood fuel necessary to operate the boiler at the desired condition.

Using the average MMBtu/lb (MJ/lb) values for coal and dry wood dust, the weight of each component of the coal-wood fuel mixture can be determined. Since the mixture is 97% by weight coal and 3% by weight wood, the total weight in tons of fuel is calculated in the software. The average cost per ton of coal and per dry ton of wood dust is entered into the software, but the costs can be over-ridden by the user if a more accurate value is known. This allows the software to calculate the annual fuel cost for the proposed coal-wood boiler. Since it is inexpensive in terms of fuel cost to operate a boiler with coal and wood as opposed to other more common fuels, significant energy cost savings are realized.

As the user enters cost estimates for necessary equipment based on the sizes and capacities provided by the output of the software, and the estimated increase or decrease in operation and maintenance cost is entered by the user, the project payback period can be determined based on the total cost of the project and the proposed energy cost savings. The software can provide accurate information on the proposed boiler replacement project. After the previously mentioned parameters have been entered, the software can accurately estimate the proposed capacities for a number of pieces of important equipment such as the capacity of the boiler itself in horsepower, the amount of fuel needed per year and on a per week basis, the proposed storage unit capacity, the proposed waste receptacle capacity, and the proposed electrostatic precipitator capacity. In addition, the annual estimated operation and maintenance cost is determined. Taking the total equipment cost along with the annual energy savings and the annual operation and maintenance increase or decrease, the project payback period is determined.

The accuracy in equipment size and capacity will allow the user to obtain the most accurate price quotes possible on all major pieces of equipment. All of the calculations necessary are done within the software. The sizing and capacity calculations are based on the parameters entered by the user. The sizing of the boiler is performed by determining the capacity in terms of horsepower, and then selecting the next highest rated boiler in terms of horsepower. The boiler ratings are given in increments of 25 HP (245 kW) in the range of 15 to 800 HP (147.02 kW to 7,841.5 kW). The next highest rated boiler is selected because boilers rated for the exact horsepower required may not exist, and to meet a heat requirement, a higher rated horsepower is needed so it is ensured that the boiler will be operating within its rated capacity.

All of the parameters entered into the software are vital for implementing a coal-wood co-fired boiler. The sizing and capacity determination of the boiler and accompanying equipment will allow for accurate pricing. The ability to contact manufacturers for implementing a coal-wood boiler and having specific parameters prepared beforehand will allow for much more detailed and accurate information.

RESULTS/SYSTEM EXECUTION

This section will showcase an example of how the user would use the software program most effectively. Example parameters are entered into the program. Through research, various cost estimates have been obtained for the major pieces of equipment. The cost estimates are used strictly for the example case and will not remain in the software database and output.

Example Case Study

For the example case, it is determined that the user's current boiler is a natural gas boiler which uses 97,750 MMBtu/yr (103,131.7 x 10^3 MJ/yr). The entire user input cells, aside from the pull down menu, are shaded gray. All of the output cells are shaded in yellow. Since this is not an electric boiler, the conversion is not necessary via the pull down menu. The first step is to select the "Natural Gas" option from the pull down menu in Line 1 of the software. The annual boiler usage of 97,750 MMBtu/yr (103,131.7 x 10^3 MJ/yr) is entered in Line 2. The value will remain the same in Line 3. The only time the value would change in Line 3 is if an electric boiler was used, in which case, Line 3 would show the converted units of kWh/yr from Line 2 in MMBtu/yr. The user's fuel rate is entered in Line 4 in units of $/MMBtu. Line 5 shows the calculated annual boiler fuel cost in

dollars. The user then enters the current operation and maintenance cost in Line 6. In Line 7, the annual boiler operation hours are entered. The user then enters the number of weeks per year that the boiler is in operation on Line 8. This value is used for the calculation of the storage bin capacity, which calculates the capacity of the bin needed to store approximately one week worth of fuel supply. The user then enters the boiler output on Line 9 in units of MMBtu/hr.

For this example, the user's fuel rate is \$13/MMBtu (\$13.72 x 10^{-3}/MJ). The annual operation and maintenance costs total \$100,000 per year. The annual boiler operation hours are 5,000 hours, the number of weeks per year of boiler operation is 30, and the boiler heat requirement as specified by the user is 17.6 MMBtu/hr (5.15 MJ/s).

Line 10 displays the total annual boiler cost based on the parameters entered up to this point. Figure 2 shows a screenshot from the program which includes all of the values entered and calculated up to this point. The comments that are visible on the screen can be seen in the software by moving the mouse cursor over the cells which have the red mark in the upper right corner of the cell.

The next section of the software program shows the proposed Coal-Wood Co-fired boiler parameters. Line 11 shows the recommended fuel mixture of 97% coal and 3% wood by weight. The wood moisture content should be under 20% for the fuel to perform efficiently. Above this moisture content, the NOx emissions reach a dangerous level, and the fuel will not perform as efficiently. The less the moisture content in the fuel mixture is, the more efficiently it will perform. The user then has the option of leaving the estimated proposed boiler efficiency of 80% in the input cell of Line 12, or changing the efficiency to a known value. For this example, a boiler efficiency of 80% is used. Lines 13 and 14 display the amount of coal-wood fuel required in terms of MMBtu/hr and MMBtu/yr. The example values of coal-wood fuel required are calculated to be 22 MMBtu/hr (6.44 MJ/s) and 110,000 MMBtu/yr (116.06 x 103 MJ/yr). Lines 15 and 16 display how much coal and wood fuel is needed per year in tons/yr. The values calculated here are 4,508 tons/yr (4,089.6 tonnes/yr) of coal, and 139 dry tons/yr (126.1 tonnes/yr) of wood dust. The average costs of coal and wood dust are shown on Lines 16 and 17 respectively. The default values in the software, which can be over-ridden by the user, are used for the example and they are \$65/ton

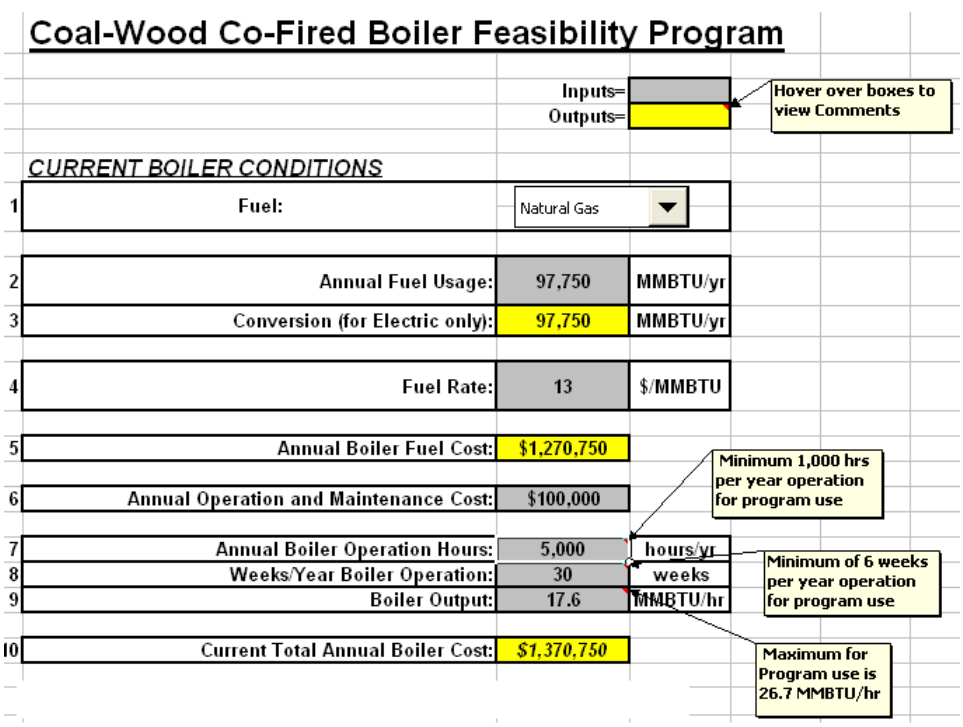

Figure 2: Software screenshot with Parameters

($71.65/tones) for coal and $25/dry ton ($27.56/tonnes) for wood. Using the average values, the annual coal-wood fuel cost is calculated to be $296,493, as shown in Line 19. Line 20 shows the annual energy cost savings, which are calculated to be $974,257 for this example.

Line 21 allows for the user to enter the expected percent increase or decrease in operation and maintenance cost for the new coal-wood co-fired boiler. This increase in operations and maintenance cost includes the hiring of any new boiler operator that may be needed, the annual cost for the removal and proper disposal of the waste fuel after it has been burnt, and the cost of energy that is required to operate any new equipment that is needed to operate the new boiler and accompanying system. In this case, the operations and maintenance costs will increase by 30%. Line 22 displays the expected operations and maintenance cost based on the current cost entered in Line 6.

Using the amount of energy input required to operate the proposed boiler which was entered in Line 9, the rated capacity of the boiler can be specified. The capacity of the boiler for this example is calculated to be exactly 657 hp (6,439.8 kW). Using the incremented system of boiler ratings, a 675 hp (6,616.2 kW) boiler is recommended for this project. This value is shown in Line 23 of the software. Using the estimated cost data obtained, the cost of this boiler, which includes standard controls, soot blowers, built in ash removal, low-NOx emission technologies, and installation is found to be $707,676, as shown on Line 24 of the software. Figure 3 shows a screen of the software showing the parameters entered and output obtained for the proposed boiler.

The next section of the software focuses on sizing the various pieces of equipment required for the boiler replacement project and also allowing the user to estimate the cost for these pieces of equipment. Line 25 calculates the tons/week of fuel usage based on the number of weeks the boiler operates per year as specified earlier. Line 26 uses this value, and based on the average density of coal, calculates the volume of the storage bin required to hold approximately one week supply of fuel. The fuel bin includes a walking floor along the bottom of the unit which

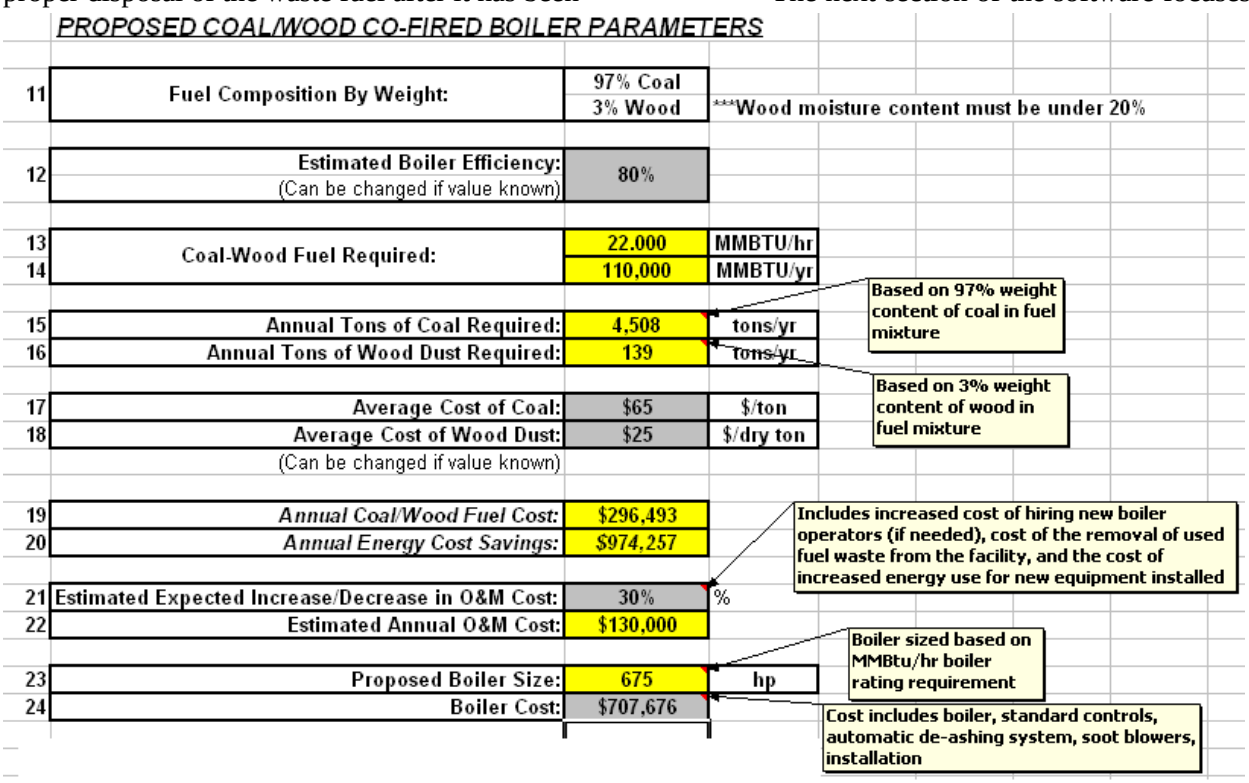

Figure 3: Software screenshot showing output

moves the fuel to one end and a metered screw auger system which then moves the fuel into the boiler from the bin. For this example, the storage bin size is calculated to be 6,000 ft^3 (169.90 m^3), with a projected cost of $122,422, which is displayed on Line 27. This cost includes the storage bin, standard controls, and installation.

The waste receptacle and the waste collection controls are then sized on Lines 28 through 30. Line 28 calculates the volume of the receptacle needed based on an average value of 12.4% of coal by weight remaining after it has been burnt [10]. Using the density of coal ash, the tons/yr and tons/week are calculated. The waste bin is sized to be able to hold approximately one week of ash waste. For the example, the volume is calculated to be 1,000 ft^3 (28.32 m^3), with an estimated cost of $50,000, as shown on Line 31. This cost includes the waste receptacle, standard controls, and installation.

Lines 32 through 33 focus on sizing and pricing the electrostatic precipitator used for dust collection. The capacity is calculated based on the ideal intake air to fuel ratio of 16:1. Since the volumetric flow of the fuel intake is known, the density of air can be used to calculate the volume of air intake to the boiler. This will also be the volumetric flow rate of the exhaust gas out of the boiler. The electrostatic precipitator is sized based on this flow capacity. For this example, the capacity of the precipitator required is 6,617 ft^3/min (3.12 m^3/s), with an estimated cost of $313,000. This cost includes the electrostatic precipitator, standard controls, and installation. Line 34 estimates the cost of the flue gas desulfurization, or “scrubber” unit. The cost is estimated to be $200,000. This cost includes the desulfurization unit, standard controls, and installation.

Based on the amount of fuel needed per hour to operate the boiler, the capacity of the coal pulverizer and the wood grinder equipment can be determined. Line 35 shows the capacity in lb/hr of the wood grinder, which is 56 lb/hr (25.4 kg/hr) for this example. Line 36 estimates the cost of the grinder to be $60,000. The coal pulverizer is determined to require a capacity of 1,803 lb/hr (817.8 kg/hr), which has an estimated cost of $140,000, as shown in Lines 37 and 38 respectively. Both of these costs include the grinder and pulverizer along with standard controls, and installation.

Line 39 shows the calculated total annual operation and maintenance cost of $130,000, and Line 40 shows the total equipment cost, which is $1,593,000. Taking the current operations & maintenance cost plus the current fuel cost and subtracting the proposed operations & maintenance cost plus the proposed fuel cost, and finally dividing the total project equipment cost with this value, the project payback period is calculated. Line 41 is the estimated cost for engineering, planning, and design for the project. These are the costs that are paid to the company that is supplying the architectural planning for the project, and for organizing and planning all of the construction. The estimated cost for this example is $500,000. Line 42 allows the user to enter any salvage value that is received for the sale of the existing boiler and related equipment. This cost is subtracted from the total equipment cost when the project payback calculation is done. The estimated salvage value used for the example problem is $60,000. Line 43 shows the project payback period for this example to be 2.15 years, or about 26 months.

Figure 4 shows a screenshot from the software containing all of the equipment sizing and pricing parameters and the payback values.

Installation and preparation of the facility for the new boiler necessitates electrical power feed that may have to be reconfigured to meet the needs of the new boiler. Also, the reconfiguration of chimneys, piping, and insulation may be required for the new boiler. The current boiler should be removed along with the removal of electrical power that is no longer required, and removal of the current fuel lines.

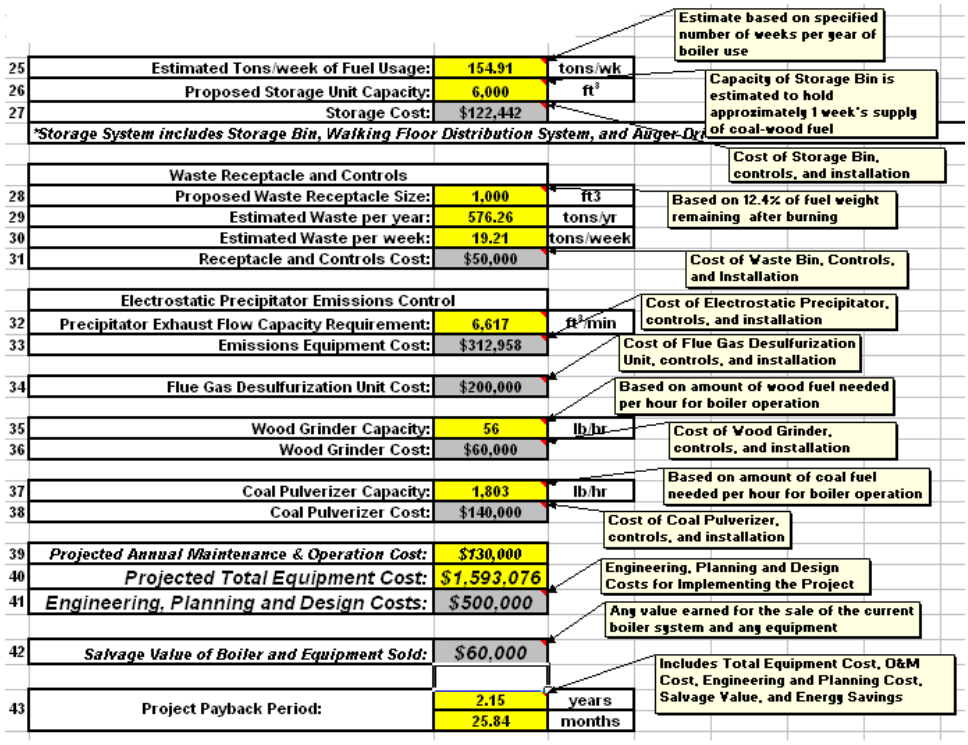

Figure 4: Software screenshot showing sizing and pricing parameters with payback period

DETERMINING MOST DESIRABLE CONDITIONS FOR IMPLEMENTATION

A sensitivity analysis on the software program was performed to determine key factors that have the greatest influence on the project payback period. The costs entered while varying each of the key parameters are based on estimates determined by contacting various manufacturers similar to the example software execution in the previous sections. The key parameters that were adjusted to determine their influence on the project payback period were the boiler size, the annual operating hours of the boiler, and the current fuel unit cost.

Boiler Size

To determine the effect of the boiler size on the project payback period, parameters were entered for boiler sizes between 100 hp (980.2 kW) and 800 hp (7,841.5 kW) in increments of 100 hp. The boiler that is considered for this analysis is a natural gas boiler with an efficiency of 87%. The current fuel rate is used as \$13/MMBtu (\$13.72 x 10^{-3}/MJ). The boiler operates for 5,000 hours a year, and approximately 30 weeks per year. The boiler MMBtu/hr (MJ/s) rating is adjusted to correspond to the boiler size in horsepower (kW). Using the theoretical efficiency, the MMBtu/yr (GJ/yr) is calculated and entered as well. The annual operation and maintenance cost is estimated for each boiler size starting with \$50,000/yr for the 100 hp boiler and increasing in \$10,000 increments up to the 800 hp (7,841.5 kW) boiler. The operations and maintenance cost is increased in increments of 5% starting at 20% for the 100 hp (980.2 kW) boiler. The waste receptacle and controls cost is estimated as \$30,000 for the 100 hp (980.2 kW) boiler and increased in increments of \$10,000 for each boiler size up to 800 hp (7,841.5 kW). The cost of the wood grinder is estimated to be \$50,000 and the coal pulverizer is estimated to cost \$100,000 for the 100 hp (980.2 kW) boiler, and are each increased in increments of \$10,000 up to the 800 hp (7,841.5 kW) boiler size. Given all of these conditions, the project payback period was determined for each boiler size. Each boiler size is plotted against the project payback period, and this plot is presented in Figure 5.

From the plot, it is determined that the larger the boiler rating, the shorter the project

payback period. This is because the larger that the boiler is, the more fuel that is required. When more fuel is required for the boiler operation, there is a greater opportunity for energy savings. Because of the significant difference in cost between natural gas and the coal-wood fuel, the energy savings increase with an increase in the boiler size. From the plot, it can be determined that coal-wood co-fired boilers are quite feasible in terms of project payback throughout the 100 (980.2 kW) to 800 hp (7,841.5 kW) range, but investment in them is more attractive at larger capacities, specifically 300 hp (2,940.5 kW) or more.

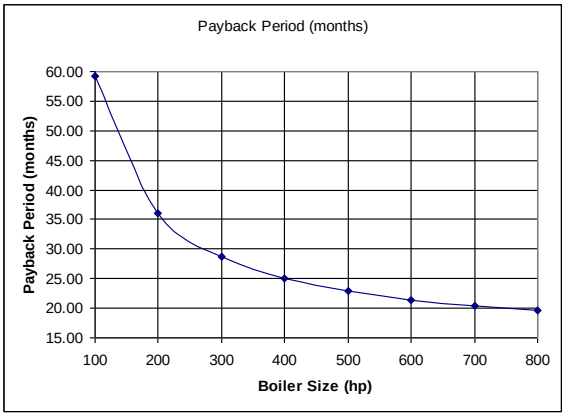

Figure 5: Plot of Boiler Size vs. Project Payback Period

Boiler Operating Hours

The sensitivity analysis of the effect that varying annual operating hours has on the project payback period was tested. From the previous analysis on the effect of the boiler size, the 400 hp (3,920.7 kW) boiler size is selected for varying the annual operating hours. All of the parameters for the 400 hp (3,920.7 kW) boiler are entered into the program, and the annual operating hours and the approximate weeks of operation per year are varied in the range of 1,000 hours per year and 8,760 hours per year in increments of 500 hours. As the annual operating hours are varied, the annual fuel usage is varied as well corresponding to the operating hours being used, the current efficiency, which is 87%, and the heat requirement. The plot between operation hours and payback period is shown in Figure 6. From the plot, it is determined that as the annual operating hours increase, the project payback period decreases.

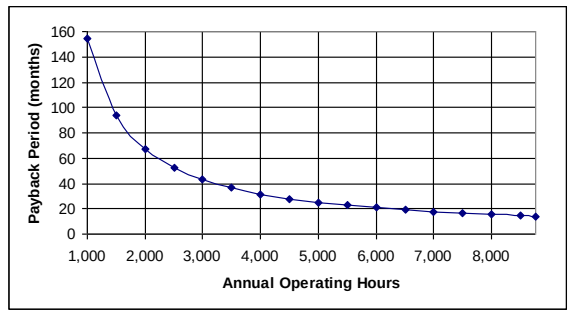

Figure 6: Plot of Annual Operating Hours vs. Project Payback Period

Implementing a coal-wood co-fired boiler is most desirable in the range of 3,000 to 8,760 annual operating hours. This is because as the annual operating hours increase, the annual energy cost savings increases as well. The project investment is paid back by the energy cost savings, and the energy cost savings is due to the amount of fuel used per year. The amount of fuel used increases as the hours of boiler operation per year increases; therefore, this generates cost savings. The greater the energy cost savings is, the shorter is the payback period.

Fuel Rate

The fuel cost that the user is currently paying for their boiler has an influence on the project payback period as well. If the user is paying a relatively low cost for their current fuel, which in this case is natural gas, the implementation of a coal-wood boiler may not be feasible as they would not be able to realize enough savings necessary to obtain a reasonable project payback period. The sensitivity analysis on this factor is performed in the range of \$5/MMBtu (5.27×10^{-3}/MJ) to \$25/MMBtu (\$26.38 x 10^{-3}/MJ) for the natural gas cost. Again, the 400 hp (3,920.7 kW) boiler and corresponding parameters are used for 5,000 annual operating hours. The plot of the fuel rate vs. the project payback period was constructed and is shown in Figure 7.

From the plot, it is determined that the project payback period is shorter with an increase in fuel unit cost. This is because with the average unit cost of natural gas already being higher than the equivalent unit cost of the coal-wood fuel, as the cost is increased beyond the average, it is obvious that the fuel cost savings

would increase. From the plot, it is determined that the fuel cost that allows for the most feasible implementation of a coal-wood co-fired boiler is approximately $10/MMBtu (10.55 x 10^{-3}/MJ) and greater.

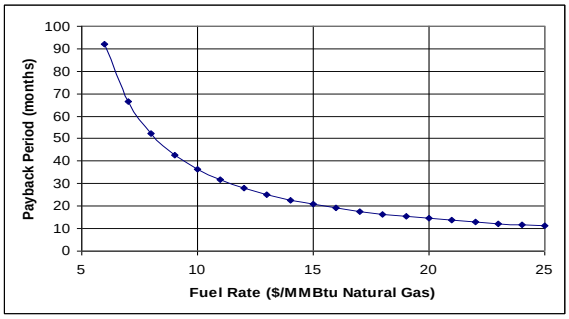

Figure 7: Plot of Fuel Rate vs. Project Payback Period

Boiler Size and Operating Hours

Sensitivity analysis for determining variations in project payback periods was also performed on two different factors at the same time. Boiler size and annual operating hours were compared against each other to see the effect on the project payback period. The sensitivity analysis considered annual operating hours between 1,000 and 8,760 hours per year along with boilers in the range of 100 (980.2 kW) to 800 hp (7,841.5 kW).

From the plot, it was determined that the project payback period is shorter as the boiler size and the annual operating hours increase. This could have been predicted from observing the sensitivity analysis for each of these two factors above. As the amount of operating hours or boiler size increases, the payback shortens. From the plot, it is determined that the combinations that allow for the most feasible conditions for a boiler replacement project are in the range of about 5,000 to 8,760 hours and between boiler sizes of 200 (1,960.4 kW) to 300 hp (2,940.5 kW). The plot generated for this analysis is shown in Figure 8.

After executing the software, analyzing the results, and performing the sensitivity analysis, the most desirable conditions for implementing a coal-wood co-fired boiler have been determined. From the sensitivity analysis, it is observed that the best conditions for implementing a coal-wood boiler is for boiler sizes greater than 300 hp (2,940.5 kW), annual operating hours greater than 3,000, and current fuel rates of about $10/MMBtu (10.55 x 10^{-3}/MJ) and greater. This analysis also helps to give the user an idea of what to expect before using the software, or if implementing a coal-wood boiler is a reasonable idea to begin with. The user can view the plots presented to determine where their current boiler falls into the range of project payback period. The user can then use the program with their specific parameters to obtain the project payback period.

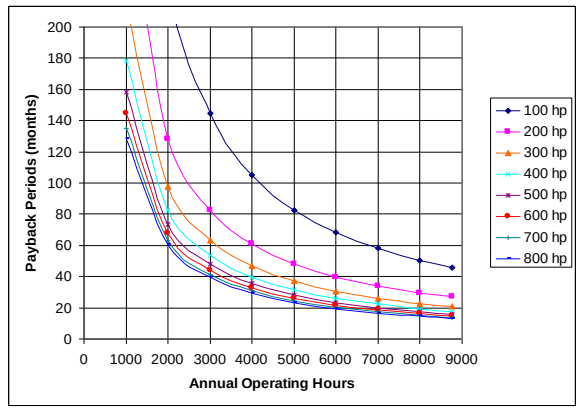

Figure 8: Plot of Boiler Size and Annual Operating Hours vs. Project Payback Period

CONCLUSION

The software program is valuable for determining if the current conditions are good for the feasible implementation of a coal-wood co-fired boiler. The user can easily review the sensitivity analysis results before entering any parameter into the software program to determine if their current conditions meet those that would likely produce the desired project payback period. Different companies and projects have varied desired project payback periods, and the software program will allow the user to determine which conditions will allow for the desired payback period. Allowing the user to know what size and capacity equipment will be necessary to meet their needs will make the process of obtaining accurate price quotes much easier than inquiring without any prior knowledge.

Obtaining accurate price quotes and having a good plan are essential in determining the projected project payback period. Without knowing all the components and costs that are included in a boiler replacement project, many

factors can be left out which will affect the payback period when they are later realized. Knowing all equipment and costs aspects of a project before beginning any actual work is very important to meet the goals and budget of the project. This software program informs the user of all the factors and components involved in the coal-wood co-fired boiler implementation process, and will allow for a smooth transition between planning and construction.

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Capture Utility Savings Using Energy Management and Reporting Systems (EMRS)

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ABSTRACT

Energy Management and Reporting Systems (EMRS) have proven effective in reducing powerhouse cost. These cost reductions are provided through effective management of equipment operation, fuel allocation, combustion optimization, and generation management by a real time closed loop control system. A recent finding is that the application of consistent operating rules across all operating shifts increases reliability and the reduction of unscheduled outages. This paper presents an automated calculation methodology to identify and capture those savings.

INTRODUCTION

An Energy Management and Reporting System (EMRS) is a closed loop energy management control system found in large industrial facilities.[12] This control system manages a powerhouse as efficiently as possible to reduce fossil fuel usage and electrical costs while maintaining process reliability. The EMRS uses a fuzzy logic and cost optimizing rule set for the operation of boilers, steam distribution, and turbine usage to drive down the cost of steam and electricity while honoring consistent operating constraints. The challenge is to forecast the savings opportunity of the control system that correctly balances reliability against cost savings because the best operating decision is one of reliable operation and not necessarily the lowest operating cost.

This paper describes an automated process to capture the savings opportunities from an EMRS class project.

BACKGROUND

Figure 1 - Simplified Process Diagram, presents the typical equipment that often appears in a powerhouse analysis for capital project approvals. The implementation process begins with a powerhouse assessment to identify the type and size of the opportunities. The assessment is shaped to the corporate project approval structure. To satisfy a typical corporate approval structure, the powerhouse assessments are now broken into Level 0, Level 1, Level 2, Level 3 and Level 4.

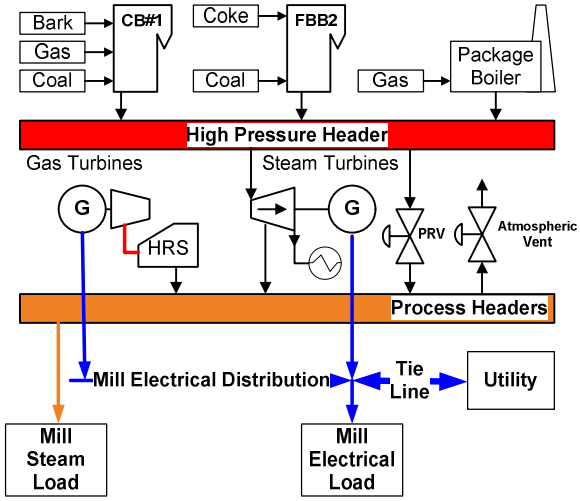


Figure 1 - Simplified Process Diagram

Level 0 - The initial study is a review of facility energy usage and unscheduled outage logs to categorize projects across the fleet.

- The first area is to evaluate the energy usage. EMRS projects have obtained energy savings of 2% to 10% of the powerhouse total energy cost.
- The second area is the cost avoidance of unscheduled outages. This is accomplished by totalizing both the unscheduled outage production and energy costs caused by control deficiencies and operator errors. The reliability savings normally exceed the energy savings.

Level 1 – Identifies if there is a project available. The objective is to inform the client of the opportunities, estimate possible returns, and provide an estimated cost per corporate project approval guidelines of usually +/- 50%.

Level 2 – Defines what type of project is to be developed. This continues to be a speculative undertaking as a well thought out solution is

developed. In the process of developing the solution, a forecast of project returns is developed and constraints to project success are identified. The result is a reduction of project uncertainty for the client and the development of a more accurate +/- 25% cost estimate per corporate guidelines.

Level 3 – Is conducted when extensive modifications are required to execute the project. An example would be the implementation of a DCS or major process modification. The result is a further reduction of project uncertainly to +/- 10% cost estimate. This may require a Front End Loaded (FEL) study.

Level 4- A process model is developed to study the effect of process modifications. Examples are the startup of an additional machine or turbine modifications.

The challenge faced in the detailed studies is properly identifying the EMRS savings opportunity and the development of the proper rule set. With the correct rule set, the EMRS will choose the proper balance of performance versus cost to assure reliable operation. A solution is to emulate the EMRS control system behavior in the auditing tool. Table 1- Typical Operating Rule Set presents a simplified operating behavior.

1. Avoid environmental limits.
2. Save the equipment.
3. Save the powerhouse.
4. Save the process.
5. Save money.

Table 1- Typical Operating Rule Set

Given that "saving money" is the lowest priority in Table 1, an analysis tool that uses the lowest cost as the primary metric will be in error. To determine the effect of this rule set on powerhouse assessments, we wrote a program that pulls 1 year of hourly averages from the process historian into a simulation that quantifies operating improvements. These simulations use actual process data to evaluate facility constraints such as tie line capacity, swing and base load boiler capacities and dynamics, and energy contract such as Real Time Pricing (RTP) against actual mill steam and electrical loads.

The Excel's Solver and steam table add-ins are driven by a Visual Basic sequencer allowing the analysis of mill performance faster and with a higher level of accuracy than using the previous manual analysis methods. The powerhouse analysis methodology is presented in the next section.

Steam System Operation Philosophy

To deal with the varying steam demands typical in industrial applications, boilers must be designed and controlled as a system to provide top efficiency at all steam demands. This requires boilers to act transparently as one continuous steam generator, as much as possible, to reduce the effect of discontinuities and transitions attributable to changing loads, variable fuel quality, and fuel mix. The various constraints on the operation of individual equipment must be respected in order to provide a robust and reliable powerhouse. The properly automated steam system should be agile enough to meet changing demands and fuel handling difficulties without excessive loss of steam to venting or propagating upsets to downstream consumers.

The operating effectiveness in powerhouse operations can be boiled down to just a few objectives.

1. Effective fuel usage of boiler and fuel allocation
2. Effective power generation of turbine and PRV coordination/allocation against electrical rates.
3. Effective steam management of generation, PRV, and atmospheric venting.

These performance objectives are evaluated over the entire mill steam and electrical load profile throughout the evaluation period. The Solver rule set evaluates the savings opportunities using the "As Found" process data and determines the “Optimized" process values satisfying the rule set. The savings opportunity is called the "Lost Opportunity" cost. It is the "As Found" operating cost minus the "Optimized" operating cost evaluated at each hour in the evaluation period. Calculated this way, the process evaluation encompasses not only the traditional equipment efficiency measures, but also the effectiveness of how the steam system is run.

The metric used to quantify the results is called the Lost Opportunity $Q_{\$LO}$ and is defined as:

$$Q_{\$LO} = \sum^{n} [(Q_{\$F\_AFi}+Q_{\$E\_\$AFi}) - (Q_{\$F\_Oi} + Q_{\$E\_Oi})]$$

Equation 1 - Lost Opportunity Calculation

Where:

$Q_{\$LO}$ = Evaluation period Total Lost Opportunity

$Q_{\$F\_AFi}$ = As Found Fuel Cost at hour i

$Q_{\$E\_\$AFi}$ = As Found Electrical Purchased Cost (+) or Sold Generation Revenue(-) at hour i

$Q_{\$F\_Oi}$ = Optimized Fuel Cost at hour i

$Q_{\$E\_Oi}$ = Optimized Electrical Purchased Cost (+) or Sold Generation(-) at hour i

Summed across the evaluation period of n hours.

Experience has shown that most steam systems are capable of vastly improved efficiency and reliability without major design changes. Analysis of operational history indicates that sustained operation at elevated performance levels has been previously achieved through operator skill and/or coincidence. This proves that the physical systems are capable of improved operation.

Implementing systems and procedures that reduce variability, drive performance towards economical operation, and apply the process manager's judgment at all times, can raise average performance dramatically. Only then does it make sense to investigate improving the inherent efficiency of boilers and turbines through capital intensive projects.

This approach essentially becomes an effort to remove all barriers to previously best-achieved operation. Design of control systems and procedures that continuously strive for reduced variability and economic operation, and remove indiscriminate operating technique become the primary tools of this approach. Reduced variability facilitates future improvement efforts because much more can be understood about the process, its constraints, and opportunities for improvement. Side benefits typically include improved tolerance for upset conditions, increased awareness of management objectives, and less, but more effective, troubleshooting efforts. Management oversight requirements are greatly reduced, allowing focus on proactive matters.

Analysis Data Handling.

Data points were taken in hourly averages for an entire year including both normal operation and abnormal operation such as outages. Hourly averages are used because they indicate the system was operated at approximately this level for an hour. This demonstrates that mode of operation was physically possible and sustainable.

Control Strategy

There are seven general knobs the EMRS uses in the course of powerhouse management;

1. Improve response to changing power prices:
    a. Lost opportunity to purchase inexpensive power though RTP or TOU rates.
    b. Lost opportunity to make power to avoid the purchase of expensive electricity.
    c. Lost opportunity to export valuable power to provide revenue.
2. Improve combustion efficiency
3. Improve fuel and boiler allocation to use the proper mix of boilers and fuels.
4. Maximizing the use of waste fuels or process waste heat for steam generation.
5. De-bottlenecking of the powerhouse and utility system.
6. Reduce atmospheric venting.
7. Improve cogeneration effectiveness by proper generation allocation and effective PRV and atmospheric venting management

Project Scope Development

The modeling challenge is to identify how far the seven or eight levers are manipulated when an operator, and therefore the EMRS rule set, will sacrifice efficiency for system reliability and stability. While the initial rule set definition captures a significant portion of that lost opportunity, a second parameter called the "EMRS Aggressiveness Factor"

is applied to define how effective each component can contribute to the required process moves.

History shows a typical utilization of the EMRS System is 85% to 95% but modules will be deactivated during equipment maintenance or abnormal operating conditions. An "Aggressiveness Factor" is used to determine that behavior.

A powerful project scope development tool can be developed by evaluating the Performance Improvement Opportunity by solving a series of System Aggressiveness ranges of 0% through 100% in 5% or 10% increments.

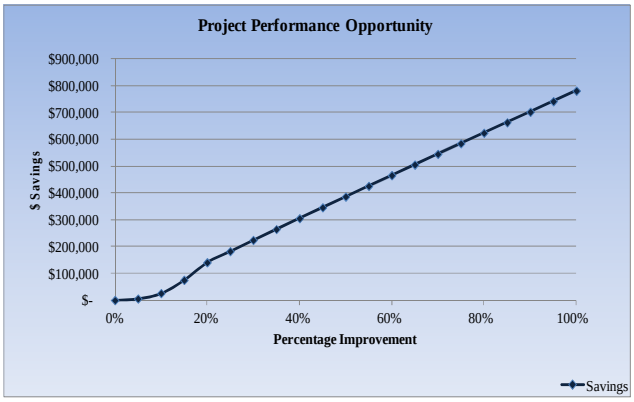


Figure 2 - Performance Improvement Opportunity

Figure 2 - Performance Improvement Opportunity presents a project savings opportunity based on different degrees of System Aggressiveness improvements. This provides a range of possible project outcomes.

The next section will investigate a Real Time Pricing study as the best way to explore this analysis process.

ELECTRIC RTP IMPORT/EXPORT ANALYSIS

Real Time Pricing (RTP) utility rate schedule permits facilities to purchase electricity at different rates during the course of a day. Also, facilities with generation assets can also be authorized to export generation by the local utility. Many existing plants export or import electricity without fully analyzing the impact of the electrical rates on operating costs. By identifying the performance capabilities of the powerhouse and comparing them with the price of electricity provided by utilities, we are able to identify potential savings or additional revenue by managing the generation of the powerhouse more effectively.

Consider a powerhouse configuration in Figure 1 that has both a condensing steam turbine and gas turbine electric generators. During this period, the evaluation fuel cost break point for the condensing turbine electricity is $32/MWHr and the breakpoint for the gas turbine is $80/MWHr when operating near full load.

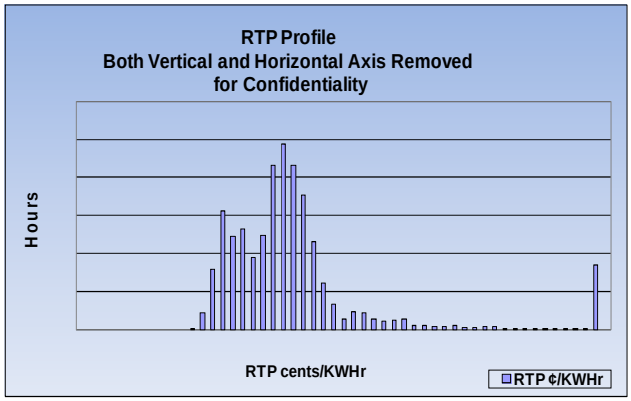


Figure 3 - Typical RTP Price Distribution

Figure 3 - Typical RTP Price Distribution illustrates a typical distribution of RTP prices during the evaluation period. This RTP distribution profile for the different generating breakpoints are summarized in Table 1.

Region	Electricity Price	Hours
1	Less than $32/MWHr	2000
2	$32 to $80/MWHr	5800
3	Greater than $80/MWHr	440

Table 2 - RTP Distribution Profile[1]

Figure 4 - RTP Import and Export Regions for Target Performance

presents the expected electric generation and tie line performance profiles for each region. The steam condensing profile is the yellow line and the gas turbine generation profile is the green line.

[1] Figure 3 - Typical RTP Price Distribution Figure 3 and Table 2have been modified to remove confidential information

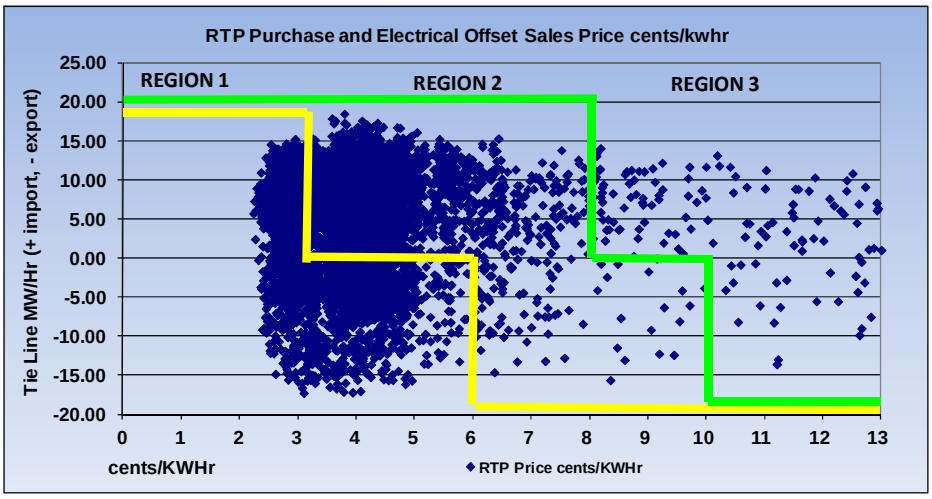


Figure 4 - RTP Import and Export Regions for Target Performance

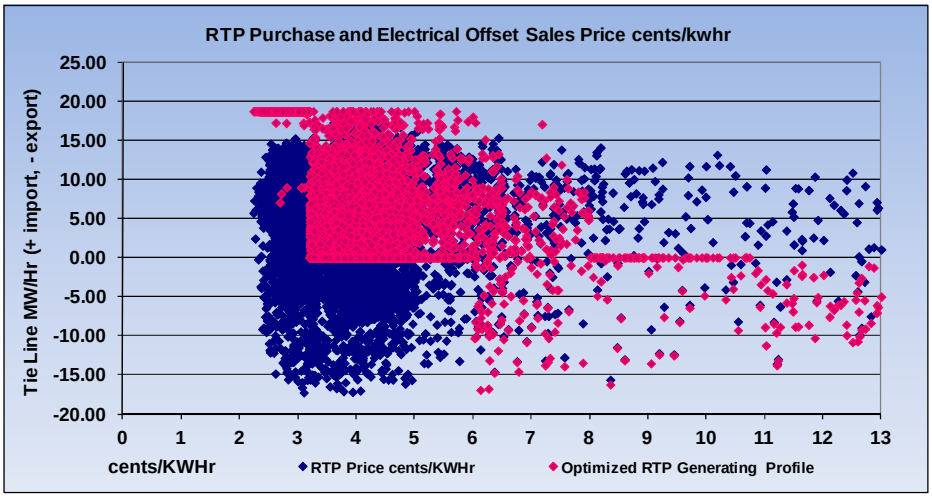


Figure 5 - Ideal Performance

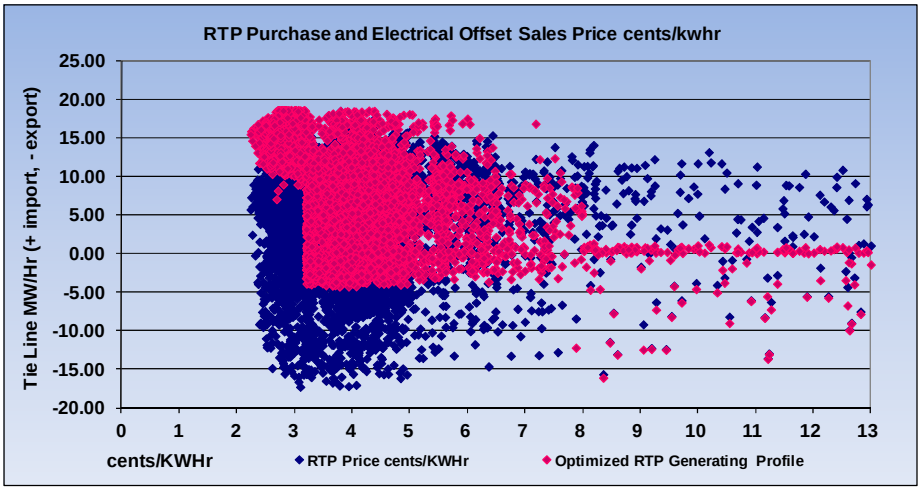


Figure 6 - Expected Performance

Region 1: Electrical purchase price below the $32/MWHr will minimize both condensing (yellow line) and gas turbine operation (green line) until reaching an import operating constraint of 18MW which is the operators preferred limit for the tie line. The maximum tie line capacity is 20MW.

Region 2: In this operating region, greater than $32/MWHr and less than $80/MWHr where the condensing turbines are responsible for the tie line management to 0 MW. The gas turbines are only used for process upsets or equipment outages. The condensing turbines should be generating to 0 MW tie line import/export. Once the exporting power sell price is greater than the generating cost, the condensers should maximize generation until reaching an operating constraint which is normally boiler steam generation.

Region 3: In this region, RTP electric purchase price is equal to or greater than $80/MHr. The condensing turbines are already maximized from Region 2 and the gas turbines are responsible for the 0 MW tie line management. Once the electrical sell price is greater than the gas turbine operating cost, the gas turbine generation increases to the next constraint which is the operator preferred 18MW export of the 20MW tie line rating.

A comparison of "As Found" performance in Figure 4 and the "Optimized" ideal performance in Figure 5 shows process mismanagement. The expected values of equipment performance were run to determine the expected performance in Figure 6. This performance estimated 90% utilization of the turbines, PRV's, and atmospheric vents with 75% to 80% on two power boilers. Figure 2 - Performance Improvement Opportunity varies the boiler performance to show $600K/year savings at 80% boiler aggressiveness.

The advantage of this analysis approach is to verify the subsystem performance and verify that the rule set was correct. The automated Solver provides an analysis of the process subsystems to compare the "As Found" and "Optimized" operating results. . Figure 7 - Tie Line Revisions presents the changes to the tie line operation. The two significant findings are:

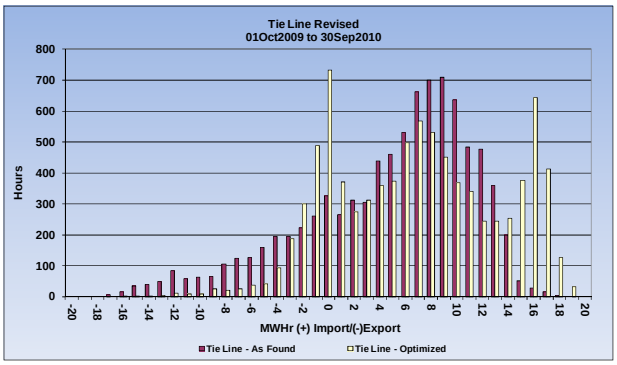


Figure 7 - Tie Line Revisions

1. At (+)14 MW to (+)18MW tie line import savings are obtained by reducing generation and the use of expensive fossil fuel and increase the purchasing of lower cost electricity from the utility.

2. At (-) 2 MW to (-)17 MW tie line export savings are obtained by reducing generation to avoid sale of electricity below cost. The study found that $410K of fuel was used to obtain $18K in net profit from electrical billings for a 4% return. With an improved generation management program, the $18K net profit was obtained with a $40,000 fossil fuel expenditure for a 45% return and less wear and tear on equipment.

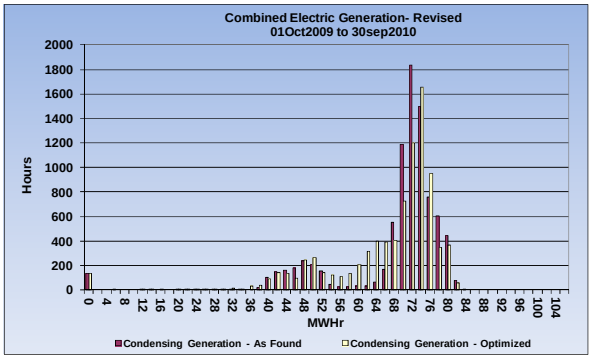


Figure 8 Combined Electrical Generation

Figure 8 Combined Electrical Generation presents the changes in steam generator loading. There is a general decline in generation in the 77MW to 84MW generation hours and increasing the lower 52 MW to 62MWH generating hours.

AUTOMATED PROCESS ANALYSIS

Powerhouse Assessment

By using the Solver and steam table add-ins available for Microsoft Excel©, we can establish an objective function to minimize the cost of operation while honoring numerous constraints such as mass and energy balances, tie line limits, and mill steam load to name a few.

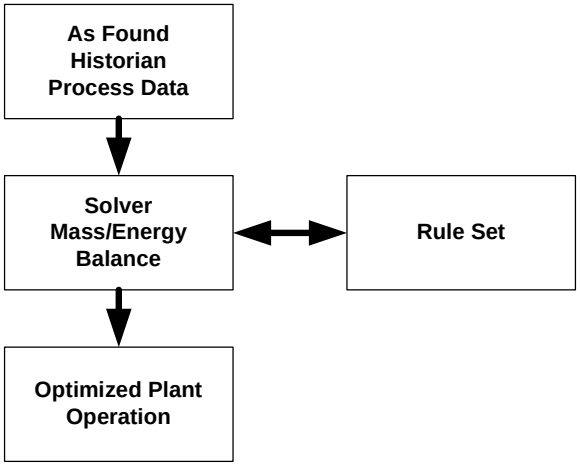


Figure 9 - Automated Analysis Process

Figure 9 - Automated Analysis Process presents the calculation protocol. The process requires "As Found" hourly average data from the powerhouse historian. A rule set of process constraints defines the operating boundaries. In addition to the equipment specifications, the impact of emissions regulations[3], energy contracts and other factors combine to provide a rule set that identifies the minimum and maximum operating points of the powerhouse equipment. These rule sets are then input into the program and can be incorporated into mass and energy balances of the powerhouse steam flow electrical capabilities of the plant.

Figure 10 - Solver Sample Workbook shows a sample of the workbook used for data analysis. Process data is pulled from the mill historian and is loaded into the data section of this workbook. The workbook is broken up into four main sections:

1. Section 1: The hourly data is transferred to the data analysis portion of the program and constraints such as minimum and maximum boiler steaming rates, tie line capacity and steam costs are defined for use in conjunction with solver.

2. Section 2: The data is analyzed via solver using the defined constraints in Section 1 to optimize powerhouse operation.

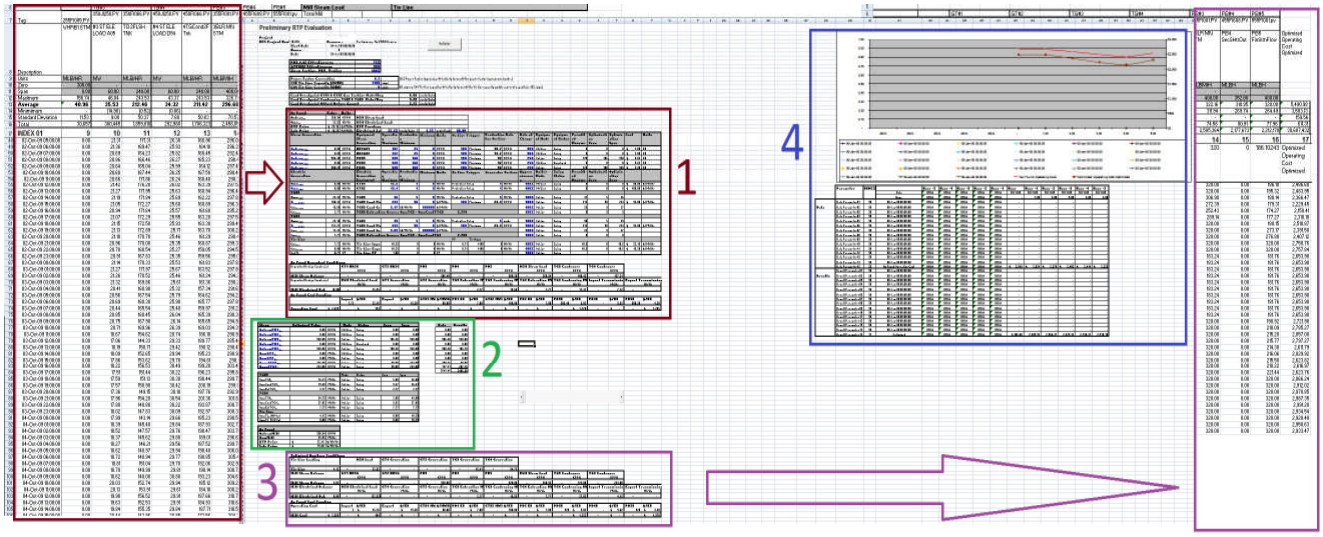


Figure 10 - Solver Sample Workbook

3. Section 3: The optimized values are then transcribed automatically to a results page that contains checks to ensure steam and energy balances as well as capture any abnormal errors that occurred during processing. The error flags allow individual hours of anomalous results to be investigated manually and corrected.

4. Section 4: This section provides graphical representation of the optimized versus the as found values of plant operation costs. Figure 11 - Solver Display presents a fully populated solver display. Any process data analyzed, such as boiler steam rates, tie line utilization, electrical generation, rule set triggers and totalized savings can also be displayed here.

Given the model and rule sets, we can then minimize our operating cost objective function while meeting all constraints. Using Excel 2007 running on custom built Intel Core i7 920 Quad-Core processors with 12GB of DDR3 RAM and solid state drive for data access, the program takes approximately two and a half hours to perform a Level 1 study on one year of data. A Level 2 study takes 12 hours to do a more detailed analysis. When process or energy contract constraints are identified they can be altered and the Solver rerun to identify savings after modifications to the powerhouse operation model. A limitation of the standard solver is a 200 parameter limit. This limitation can be overcome with commercially available upgrades.

On Line Performance Assessment

There are reporting advantages to a constantly optimized process system. The process operates against constraints that can be identified and the effect on the process optimization quantified. The on line EMRS includes calculations for the ideal steam generation and distribution system operating in parallel with the real time process control system. The ideal system is based on actual steam demand, equipment availability., limits, and current process constraints. The cost difference between the ideal system and actual system is the lost opportunity and calculated for each boiler fuel, turbine, and vents every second. The differences are aggregated to daily, monthly, and yearly totals. This permits an automated reporting of the system performance and identifies operating trends that require correction.

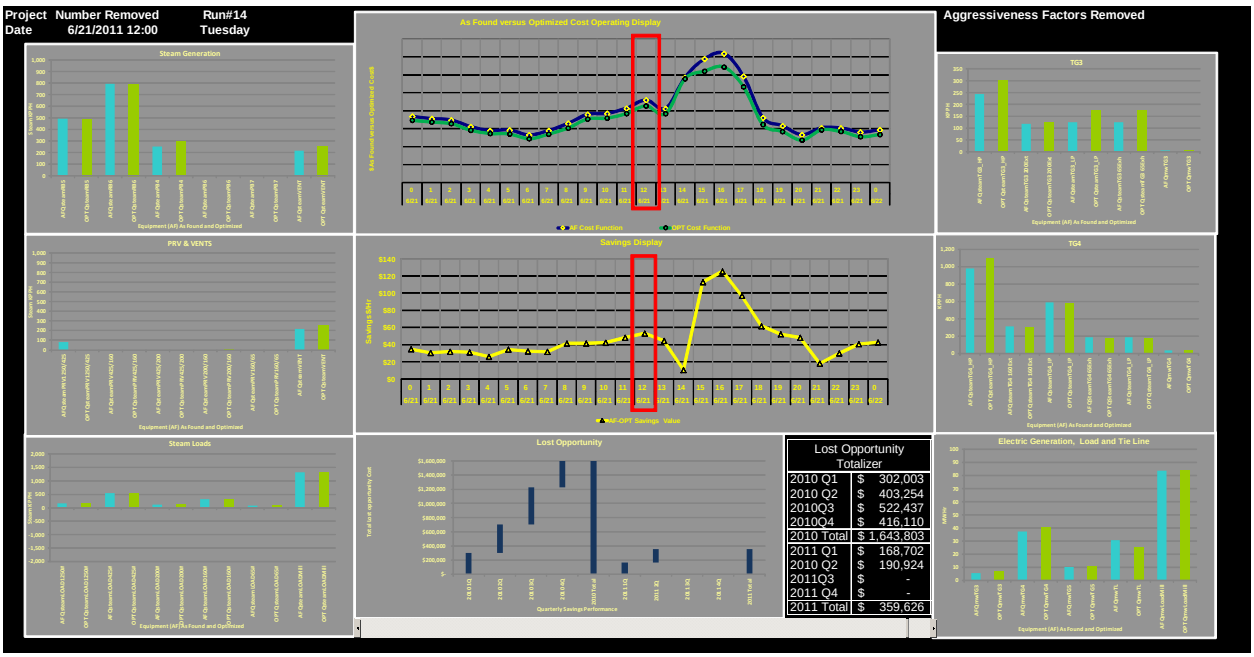
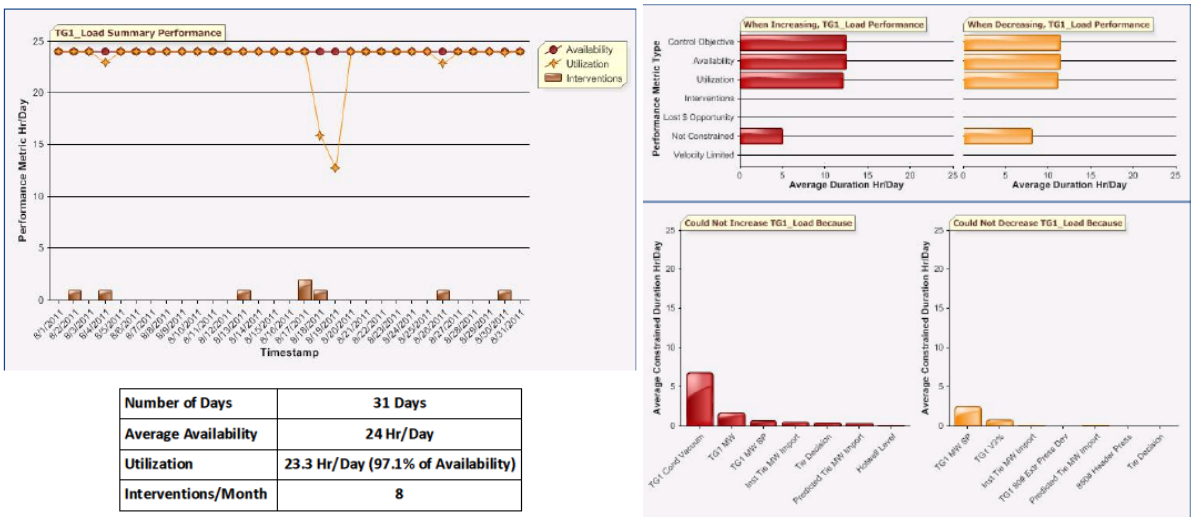


Figure 11 - Solver Display



Number of Days	31 Days
Average Availability	24 Hr/Day
Utilization	23.3 Hr/Day (97.1% of Availability)
Interventions/Month	8

Figure 12 - On Line Reporting System

Further benefits are found in Figure 12 - On Line Reporting System. This is an example of the constraint reporting mechanism that identifies individual subsystem performance. The left chart presents the utilization of the TG1 condensing turbine performance module during August 2011. The module was active for 97% of the time and the operator intervened to make 8 setpoint changes.

TG1 load was asked to either increase or decrease roughly half of the time. This indicates that TG1 load was primarily controlling the high pressure header. The condenser vacuum limited TG1 load increases about 7 hours/day (about 56% of the time). Load decreases were mainly limited by low MW setpoint (about 2.5 hours/day of 22% of the time).

The TG1 lost opportunity cost of actual performance compared against the ideal performance was $122K. Each operating output is tracked and the constraints associated with that output reported. This allows operations to prioritize corrective actions to systematically remove process constraints to increase value. This type of reporting system changes the overall system analysis paradigm from "How did we do?" to "How can we do better?"[4] to obtain long term sustainable results.

CONCLUSION

From the auditors standpoint, this methodology makes the powerhouse assessment a repeatable protocol that significantly reduces the time required for audits, increases the accuracy of the studies, provides consistent evaluations across a fleet of powerhouses and improves the accuracy of the final reports. Operating constraints are tabulated to simply the collection and verification process. Program operating errors have associated codes that are consolidated into a searchable table for review and corrections to modify rules or identify process problems.

The online reporting analysis operates in parallel with the EMRS process control optimization allowing a before and after comparison of actual performance against the ideal model. The reporting system operates in a similar manner to the original powerhouse assessment to track lost opportunities and the associated operating constraints that require attention to improve system performance.

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Introducing an Online Cooling Tower Performance Analysis Tool

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ABSTRACT

Cooling towers are used extensively for numerous industrial, residential, and commercial applications. Yet despite how common their uses, operators often do not know how to properly evaluate and optimize their performance. This is due to the complex and variable nature of all of the factors that can influence performance; fan speed, wind speed, sump temperature, heat load, ambient temperature, relative humidity, etc. This can be overwhelming for a regular operator resulting in many cooling towers being set to a default operating condition and forgotten.

This paper will introduce a web-based cooling tower analysis tool being developed to help users understand and optimize operational efficiency. The calculations, evaluations, and models will be discussed in detail to highlight important design considerations and issues. This will include how the Merkel Theory, psychometric properties, tower types, and historical weather data are incorporated into the analysis.

INTRODUCTION

Cooling tower users often have a very limited understanding of the specific operating conditions of their towers because of the constantly changing air conditions and overall complexities of the energy and mass transfers.

There are a few high-level cooling tower analysis tools available. However, they generally have a minimum cost of a few hundred dollars, almost always need to be installed locally, are designed for users with advanced cooling tower knowledge, and only provide limited details of the underlying calculations.

The Online Cooling Tower Performance Analysis Tool is being developed to provide cooling tower operators with a simplified, straight forward way to quickly analyze their towers with clear and complete details of how the analysis was done and what the results mean. Making it web-based further increases the accessibility by removing any installation and compatibility issues. The overall analysis itself is also quite powerful as it incorporates the best cooling tower theories, fan models, and psychrometric properties formulations currently available.

Operators will be able to rapidly evaluate any potential operational adjustments to determine likely impacts on performance and overall efficiency and clearly understand of how and why.

The discussion of the cooling tower tool will also be used to highlight development issues and concerns with energy analysis tools in general. From simple calculators to complex modeling software, these tools always provide results, but regardless of how powerful the tool potentially is the end-user's experience always determines the tool's true value.

ANALYSIS SOFTWARE TOOLS

There are numerous analysis tools available for all types of equipment with a wide range of quality and associated costs. Unfortunately there are often many issues with these tools:

- Learning Curve
- Installation
- User-Interface
- Low Visibility / Awareness
- Black Box Calculations
- Simplifications / Generalizations
- Perceived Value vs. Cost

The major source of many of these issues is the naturally dissimilar interests of the three main parties involved:

- Engineers
- Developers / Programmers
- End-Users

When engineers actively work with developers and both seriously consider the needs of end-users, very useful, powerful tools can be developed. Unfortunately, often the engineers and developers each have their own vision of what a tool should be and the final result is a tool with many of the previously mentioned issues that can confuse and, in the worse cases, potentially mislead end-users.

To combat this in the development of the cooling tower tool, a set of specific development criteria were assembled with the focus on the end-user experience, as that is the most important feature.

In order to attract users, the tool has to be perceived as worth more than the effort to obtain, install, and learn. To keep users, the tool has to actually deliver something of value.

TOOL DEVELOPMENT CRITERIA

In order for the tool to be both easy to use and powerful, the following development criteria were established:

- User-Centered Design
- Fully Web-Based (HTML5)
- Require Minimum Data Entry
- Calculate Psychrometric Properties
- Model Cooling Tower Operation
- Model Fan Operation and Adjustments
- Easily Understandable Analysis and Results

User-Centered Design

In order for the tool to be useful to the target audience the design had to focus on the needs of a typical cooling tower user. Existing cooling tower analysis tools tend to try to showcase how powerful they are by providing a large number of options and features. This is useful for advanced users and designers but can be a steep learning curve for most cooling tower operators. With this in mind, the data input requirements for this tool were reduced as much as possible while still permitting a detailed modeling and evaluation of a given cooling tower.

Additionally, a series of simple calculators were included that permit the user to evaluate any factor related to the cooling tower without having to model it entirely. These include determining individual psychrometric properties of air and fan curve adjustments.

Fully Web-Based (HTML5)

A fully web-based tool is much easier to use immediately. Downloadable tools include hardware and software system specific installation requirements and account privileges, either of which the user may not meet or have. This tool has been designed to the current HTML5 standard [8] to further enhance compatibility so that it will work immediately and correctly on any device with an internet connection and the current version of any major web browser.

Require Minimum Data Entry

Commonly users are asked to enter extensive amounts of data when only a subset is actually required and much of the data can be calculated or reasonably approximated. This is generally done to simplify development by reducing calculations in the software, to adjust the model in extremely fine detail, or to try to highlight how powerful the tool may be.

With the cooling tower tool, the goal was to only require the minimal data entry needed to generate a reasonably accurate model. For a basic model, these data requirements were determined to be:

- Ambient Wet-Bulb Temperature
- Air Volume Flow (ACFM)
- Water Inlet Temperature
- Water Outlet Temperature
- Water Volume Flow

Additional alternative and optional data fields are available. For example, users may enter ambient dry-bulb temperature and relative humidity instead of wet-bulb, which the tool will then calculate. Advanced users can also provide a variety of additional data to adjust and fine tune a number of other factors such as the characteristic curve slope and integration granularity. However, the tool only

requires the minimum data to perform an analysis and provide a result.

Calculate Psychrometric Properties

This tool needed to be able to determine the properties of air at a given temperature, pressure, and moisture level in order to properly calculate energy and mass transfers. There are numerous ways to do this with varying accuracy. Commonly, this has been done by interpolating from a prepopulated data table or using equations that model the desired properties.

Several property modeling equations have also been developed, and continue to be improved, that provide very powerful methods to directly calculate properties. It was decided to use these for the cooling tower tool as they provide the best flexibility, range, and accuracy. The IAPWS (2007) formulations [5] are used for the thermodynamic properties of water and water vapor. The Herrmann et al. (2009) formulas [4] are used for the thermodynamic properties of moist air. Further details of their use are described in the PSYCHROMETRIC PROPERTIES section.

Model Cooling Tower Operation

There are several cooling tower theories of analysis that use various iterative methods and differing assumptions and simplifications. The Merkel Theory (1925) [7] was selected as it provides a simple straightforward approach, continues to be the dominant theory used in cooling tower analysis, and studies comparing various methods have demonstrated Merkel produces comparable results with other more involved methods [6].

Model Fan Operation

Along with air flow, the user can provide the fan horsepower and data points from a system curve for initial operational conditions. The tool can then use the system curve and/or fan affinity laws to determine the change in fan energy requirements related to changes in the overall cooling tower operation.

Easily Understandable Analysis and Results

The analysis and results have been designed to be clear and easy to understand. Details of any of the calculations can be viewed. All cooling tower related factors are calculated and provided. Several charts, graphs, and tables provide visual representations of the heat transfer in the tower and the overall performance of the tower given various operational conditions.

PSYCHROMETRIC PROPERTIES

As a psychrometric chart is required for a manual evaluation of a cooling tower, the tool must have the ability to accurately calculate the psychrometric properties for the air at any potential condition given various initial sub-sets of properties. This includes changes in temperature, moisture content, and even small pressure fluctuations.

For a given dry-bulb temperature and pressure, the complete psychrometric properties need to be calculated from any one of the following:

- Relative Humidity
- Wet-Bulb Temperature
- Specific Enthalpy
- Specific Entropy
- Humidity Ratio

Calculating Psychrometric Properties

For a specific dry-bulb temperature and pressure, the air properties vary linearly between that of completely dry air and moist air saturated with water vapor, with intermediate properties determined by interpolation. The dry air properties can be accurately calculated using the ideal gas laws. However, accurately determining the properties of moist air is more difficult as it also requires the specific properties of water vapor which are far more complex and difficult to model.

Two methods were considered to calculate the moist air properties. The first was a lookup table based calculator which would provide approximations. The second was using current psychrometric property formulations which could provide highly accurate results.

Property Lookup Table

Using prepopulated property tables, the lookup table calculator would interpolate the properties of a specific point from the closest matches in the tables. This method is easy to understand and implement, yet can require a significant amount of data entry, with additional tables for each additional pressure. The

accuracy is also dependent on how accurately a curve can be fit between data points. This does not work well with the non-linear behavior clearly illustrated in psychrometric charts. The intervals between data points can be reduced to increase accuracy at the cost of greatly increasing the data entry requirement.

The potential for data entry errors is also an issue, increasing with the size of the table and often can be difficult to detect. The bad data points can only be detected by testing points adjacent to that data. Therefore an error-checking function would be required to compare all the points to identify outliers and this still may not detect small errors.

Psychrometric Formulations

Determining the psychrometric properties from formulations is initially very difficult as it requires coding a large number of complex equations and requires a combination of formulations for the properties of water vapor and air. However, these equations require very little adjustment and maintenance once developed.

For the water vapor (steam) properties, the International Association for the Properties of Water and Steam (IAPWS) provides a comprehensive set of formulations [5]. These formulations have been accepted as the standard water vapor properties by ASHRAE and are used to generate the water vapor properties table in ASHRAE Fundamentals 2009 [1].

The partial pressure of water vapor for saturated moist air can be approximately determined given the dry-bulb temperature. The specific pressure, at which this temperature would be the water's boiling point, is the approximate partial pressure. The difference between the approximate partial pressure and actual partial pressure is generally less than 0.5%.

To calculate the actual partial pressure requires that the approximate partial pressure, determined by the steam formulations, be multiplied by an additional enhancement factor, which has been developed specifically for this purpose. Since Goff and Gratch (1945) [3] originated the enhancement factor, various formulations have been developed. As recently as 2009, ASHRAE published updated formulations for the enhancement factor [4], which they used to generate the psychrometric properties for ASHRAE Fundamentals 2009 [1].

While all of these formulations are far more complex to implement then the lookup table method, they do provide several benefits:

- Only a few data points are needed to identify calculation errors.
- The formulation's temperature and pressure ranges are very large, far greater than anything that can reasonable be implemented with a lookup table.
- They are already used by ASHRAE to generate their published psychrometric data tables.

Selected Calculation Method

It was decided to use the psychrometric formulations as they are more accurate, powerful, and flexible. Also, any table used for the lookup method would likely have been generated from these formulations initially. While this method is more difficult to initially implement, there is no difference in how the tool would use either method once developed and the formulations provide a superior functional range and accuracy.

MERKEL THEORY

Merkel Theory (1925) [7] is the most widely used cooling tower model as it provides a simplified but reasonably accurate method to calculate the energy transfer.

Two key assumptions were made by Merkel. First, the air leaving the cooling tower is completely saturated with water vapor, which allows the state of the exhaust air to be calculated with only a temperature or specific enthalpy. Second, the mass of the evaporated water vapor is negligible, allowing the water temperature range to be assumed as proportional to the energy transfer.

Using these assumptions in combination with the energy and mass transfer equations result in the Merkel Equation:

$$\frac{KaV}{L} = \int_{t_1}^{t_2} \frac{c_p dt}{h - h_a} \qquad \text{Equation (1)}$$

K = unit conductance, mass transfer, lb/h·ft^2
a = area of interface, ft^2/ft^3

V = cooling volume, ft^3
L = inlet water mass flow rate, lb/h
c_p = specific heat of water, Btu/lb·°F
t = temperature, F
h = enthalpy of water film, Btu/lb
h_a = enthalpy of air, Btu/lb

KaV/L is often referred to as the "number of transfer" units (NTU) as it represents the number of times the enthalpy difference ($h - h_a$) is transferred. It should also be noted h, the "enthalpy of water film", is the enthalpy of saturated air at the same temperature of the water (as it represents the film around the water) and not the enthalpy of the water itself.

The cooling tower tool implements the Merkel theory by numerically iterating over 10 points of the temperature range. If desired, advanced users can adjust the number and location of these points.

OPERATIONAL ADJUSTMENTS

Cooling towers are most often characterized by the ratio L/G [2] where:

L = mass flow of water, lb/h
G = mass flow of air, lb/h

The operator can adjust either of these flows which change the overall operation of the cooling tower and adjust the L/G ratio.

The impact of any adjustment on the cooling tower can be predicted using the L/G ratio with the following relation:

$$KaV/L = C\,(L/G)^{-m} \qquad \text{Equation (2)}$$

C = tower specific constant
m = tower specific slope

Referred to as the characteristic curve of the cooling tower [2], this equation predicts the KaV/L for any value of L/G once the constants have been determined. This can be done in two ways. First, with two separate test points for a cooling tower, both C and m can be calculated. Secondly, if only one test point is available, m can be estimated as most cooling towers fall between -0.55 and -0.65 (the tool currently uses -0.6) and then C is calculated.

Once a new KaV/L has been determined for a new L/G, the Merkel Theory can be iteratively evaluated to determine the change in water and air temperatures. This is done by setting the inlet air conditions and water temperature range, then varying the inlet water temperature until the KaV/L is matched.

It is done this way as it is assumed that the heat load is proportional to the water temperature range. Assuming that the air flow is reduced, the water temperature will increase until the tower is dispersing the same amount of heat as it was with the initial air flow.

There are limits to how much the flows can be adjusted in this way. The air flow can be reduced, or water flow increased, to the point where the air is saturated and reaches the water inlet (hot) temperature before it exits and is unable to remove any more heat. The air flow can also be increased, or water flow reduced, to the point where the exit air is no longer saturated. Both cases result in significant reductions in the efficiency of the tower.

Within these limits, the tower's efficiency is primarily dependent on the water outlet temperature (often called the sump temperature). Increasing the air flow requires more fan energy, but reduces the water outlet temperature. If the equipment or process using this water can benefit from a lower temperature, the additional fan energy might be offset. At the same time, if there is a minimum required temperature, there is no benefit in reducing the temperature further and the cooling tower may be optimized by setting the fans to maintain that temperature.

ANAYLSIS AND RESULTS

The tool analyzes the cooling tower by first modeling the initial conditions, determining the exit air properties, KaV/L, and C values. Then it determines the maximum and minimum limits for L/G, using the initial ambient wet-bulb temperature and water temperature range. This provides the range of acceptable operational adjustments. Then a curve is generated for the water outlet (cold) temperatures as they vary with L/G.

If the initial fan energy is provided, a curve is generated for the fan energy versus the air flow and related L/G (assuming a constant water flow). If the

user sets a minimum required water outlet temperature, the energy savings (or cost) associated with the adjustment from initial conditions can be calculated.

The calculations and energy balances are displayed to support the results. All generated curves are provided to the user in both graphical and tabular formats.

The user can also test and compare various configurations by additionally varying the water flow, water temperature range, and ambient air temperature conditions.

The tool also:

- Quantifies the benefits of multiple towers.
- Indicates s if significant fog is likely, based on the air conditions.
- Calculates % design flow, given initial design parameters

SUPPORTING CALCULATORS

Several supporting calculators are included in the cooling tower tool. These allow the user to calculate various cooling tower related values without having to generate a complete model.

Psychrometric Calculator

The psychrometric calculator allows the user to determine the complete psychrometric properties of air given the dry-bulb temperature and pressure and any one of the following:

- Relative Humidity
- Wet-Bulb Temperature
- Specific Enthalpy
- Specific Entropy
- Humidity Ratio

A psychrometric chart is also provided, which the user can click on to determine various conditions.

NEXT STEPS

As the cooling tower tool is further developed, the following additional features are planned:

Regional Weather Data

Currently, the tool only evaluates a cooling tower for a single specific set of conditions. Regional weather data will be added to allow a user to enter a location and have the cooling tower performance analyzed over a full year using the typical weather for that area.

Downloadable Analysis Report

The tables, graphs, and calculations are currently only provided online. A downloadable PDF version of this report is planned that will allows users to save a copy.

NOTES

Merkel assumes the mass transfer from evaporation to be negligible. Depending on the conditions, it can be about 1% of the water's flow rate.

Due to the alignment of the enthalpy and wet-bulb lines on the psychrometric charts, the change in wet-bulb is proportional to the change in enthalpy.

The fan and pump energy are the only energy required to operate the cooling tower. This version of the cooling tower tool assumes that the pump energy (and water temperature range) will remain constant unless the user specifies a change.

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Opportunities and Barriers in the Implementation of Energy Efficiency Measures in Plastic Manufacturing

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Abstract

The plastic industry in the U.S. employs approximately 9% [1] of the manufacturing work force and consumes approximately 6% [1] of the total energy used by the U.S. industries. According to the Department of Energy (DOE), manufacturers of plastic and other resins are consuming nearly 1,070 trillion Btu [1] of energy in their operations every year, valued at $6.0[1] billion.

As escalating energy prices continue to be a concern for industry, many plastic manufacturers are striving to reduce their energy consumption to stay competitive. An alternative to reduced energy consumption is to put in place an energy efficiency strategy. However, while most plastic manufactures are aware of the energy efficiency opportunities in their facilities, the implementation of these opportunities face certain market barriers. These barriers are identified as customers lack the information about energy efficiency technologies, and have limited capital funding to implement the energy efficiency measures. Additionally, it is hard to identify the energy savings opportunities and difficult to quantify their impacts.

The purpose of this paper is to discuss the various energy efficiency opportunities in plastic manufacturing and address the market barriers in implementing them. We will identify the energy savings opportunities in plastic manufacturing that can be introduced to reduce energy consumption and decrease production costs, thus giving the customers more competitive edge in both the regional and global markets. We will also discuss various popular energy efficiency measures, the energy savings associated with each measure and their projected simple payback. In terms of policy implication, this paper will discuss various strategies of mitigating potential market barriers in implementing energy efficiency measures on plastic manufacturing industries.

Introduction

Plastics are known as one of the most resource efficient and flexible materials available to the society. Their light weight, strength and versatility make them applicable to a wide variety of applications ranging from packaging materials, household products, construction, automobile, transportation, electrical and electronics appliances, medical equipment and space travel devices. Due to its diverse function, it is not surprising that each of us consumes in excess of 100 kgs [2] of plastics every year.

Plastic processing sector is characterized by many different processes such as injection molding, blow molding, rota-molding, extrusion, thermoforming and vacuum forming. Resin polymer is used as raw material that is being shaped into a mold or a die through applying a combination of heat, pressure and cooling in these processes. All of the processes involved in the plastic manufacturing use high energy intensive equipment which consumes an enormous amount of energy. By implementing various energy efficiency strategies, plastic manufacturers could significantly reduce their energy and operating cost in order to stay competitive. A DOE study on plastic plants has shown that approximately 9.7 % [1] reduction in energy consumption can be achieved through implementing various energy efficiency measures to the process.

This paper serves as a guide to facility managers and decision makers in plastic manufacturing to identify energy efficiency opportunities and help them understand the benefit from implementing these measures.

ENERGY USE IN THE PLASTIC MANUFACTURING

Although plastic manufacturing process is lot more efficient than other production processes, they still consume a substantial amount of energy. DOE and other data indicate that plastic and other resins manufacturers are using 1,070[1] trillion Btu of energy annually in the U.S. Electricity is primarily used as a power source for these processes and the energy consumption is generally split in the following ways in a plastic manufacturing plant:

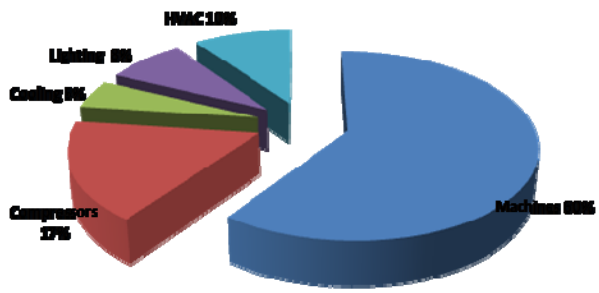

Figure 1: Energy Balance of a Plastic Processing Plant[1]

ENERGY EFFICIENCY OPPORTUNITIES IN THE PLASTIC MANUFACTURING

Figure 1 above shows that about 60% of the total energy consumption is from the process-related equipments and their operation presents the greatest opportunities for energy savings. The section below details various popular energy savings opportunities that can be introduced in a typical plastic manufacturing facility.

1. Retrofit variable speed drives (VSD) on hydraulic injection molding machines (IMMs): Variable speed drives (VSDs) are common energy efficiency retrofits for hydraulic injection molding machines. A VSD adjusts the speed of the motor to optimize the volume of fluid being pumped by the molding machine. Basically, the VSD sets the motor speed for different stages of the product cycle so that for each portion of the cycle, only the required flow is pumped, therefore maximizing the energy savings. Most of the VSD installers claim 20-50% [3] savings of the pre-retrofit energy usage for machines with a constant speed motor. However, according to recent measurement and verifications done on numerous hydraulic molding machines, it provided a more accurate energy savings estimate for this measure. This field measurement was performed on 29 hydraulic molding machines of various capacities ranging from as low as 500 tons to as high as 1,100 tons. Each of the 29 machines was metered before and after the VSD installation. The metered data was analyzed and the energy savings calculated ranged from 30% to 42%. On an average, the energy reduction for each machine was approximately 39% from retrofitting a constant speed hydraulic molding machine with VSD. Figure 2 shows the comparative energy usage of a 1,100-ton hydraulic molding machines with and without variable speed drive, whereas Figure 3 shows the comparative energy usage of a 500-ton hydraulic molding machines with and without variable speed drives.

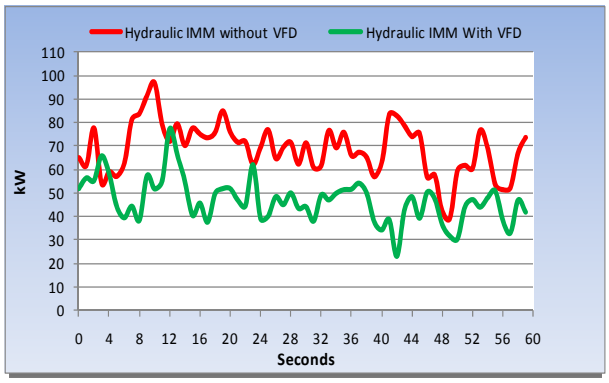

Figure 2: Comparative Energy Usage of an 1100 Ton Hydraulic Machine With or Without VSD[2]

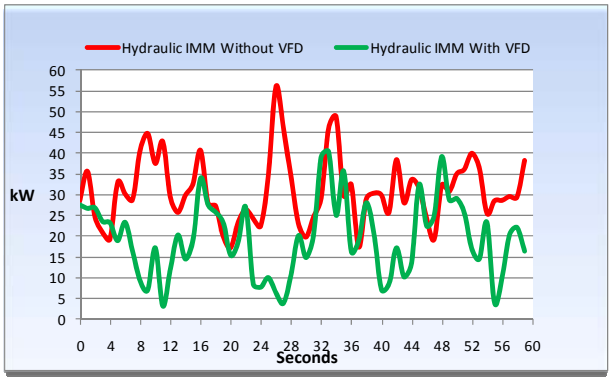

Figure 3: Comparative Energy Usage of a 500 Ton Hydraulic Machine With or Without VSD[3]

2. Insulate injection mold barrel heaters: Barrel insulation jackets are an economical method to reduce the energy consumption of the heating

[1] Hwww.leonardo-energy.org

[2] Energy profiles are based on DNV KEMA's monitored kW data

[3] Energy profiles are based on DNV KEMA's monitored kW data

element of the molding machine. They work exactly the same way as the insulation jacket in the domestic hot water tanks. This measure saves approximately 20-22%[4] of the heater energy. Table 1 shows the energy savings associated with the installation of insulation jacket on an injection molded barrel heater.

Table 1: Comparative Energy Usage of a Barrel Heater With and Without Insulation Jacket

Comparison of Cylinder Heater Bands With and Without Insulation Jackets			
Without Insulation Jackets		With Insulation Jackets	
Power Draw(kW)	Emission Temp ° F	Power Draw(kW)	Emission Temp ° F
33.67	230	26.28	122
Energy Savings 22%			
Source: Nickerson Europe Ltd.			

3. Replace hydraulic injection molding machine with all electric injection molding machine: All electric machines are a direct energy efficiency replacement for hydraulic injection molding machines as the power requirement can be provided by high speed electric servo motors. This eliminates the need to cool the hydraulic oil which saves some cooling energy. Studies and experience have shown that all electric machines have the potential to reduce the energy consumption between 30-60% [4]as compared to hydraulic injection molding machines of the same capacity. Recent data collected from measurement and verification of injection molding machine projects have shown more than 70% savings in all electric machines as compared to hydraulic machines of equal capacities. Figure 4 and Figure 5 show a comparison of energy consumption between hydraulic IMM and all electric IMM with different parts. Both the metered machines were rated at 300 ton. Table 2 shows the actual annual energy savings and peak demand savings estimated with the metered data and overall energy savings for an all electric IMM were approximately 73% as compared to a hydraulic IMM.

[4] Nickerson Europe Ltd

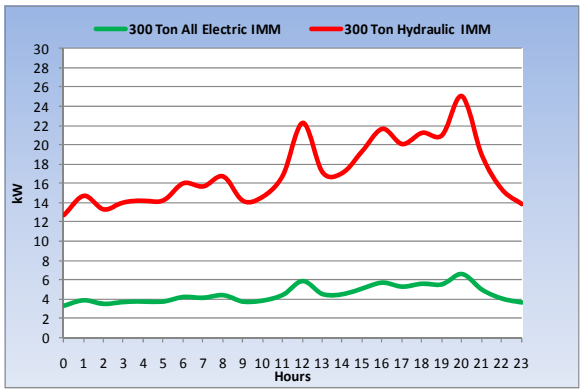

Figure 4: Comparison of Energy Consumption between Hydraulic IMM and All Electric IMM with Part-A[5]

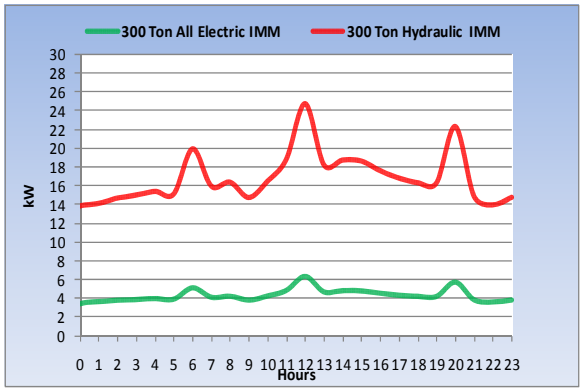

Figure 5: Comparison of Energy Consumption between Hydraulic IMM and All Electric IMM with Part-B[6]

Table 2: Electric and Hydraulic Energy Consumption Comparison[7]

	Part A		Part B	
Capacity	300	Ton	300	Ton
Hyd IMM Annual Energy Consumption	145,218.73	kWh/yr	144,056.98	kWh/yr
Hyd IMM Peak Demand	26.38	kW	26.47	kW
Elct. IMM Annual Energy Consumption	38,263.64	kWh/yr	36,466.62	kWh/yr
Elct. IMM Peak Demand	6.66	kW	5.52	kW
Annual Energy Savings	**106,955.09**	**kWh/yr**	**107,590.36**	**kWh/yr**
Peak Demand Savings	**19.72**	**kW**	**20.94**	**kW**
% of Energy Savings	**73.7%**		**74.7%**	
Annual Cost Savings	**$ 12,667.36**	**$/yr**	**$ 12,853.24**	**$/yr**

[5] Energy profiles are based on DNV KEMA's monitored kW data
[6] Energy profiles are based on DNV KEMA's monitored kW data
[7] Energy savings are estimated based on the kW data collected from the 300 ton IMMs and annual cost savings are based on the energy rate of $0.10/kWh and demand rate of $100.00/kW

4. Retrofit high-efficiency pump system on hydraulic injection molding machine: This high-efficiency pump system consists of three elements: a reciprocating pump, a prime mover and an eccentric transmission which is coupled to the pump. This technology is called infinite turndown technology (ITDT). This ITDT is designed to deliver maximum pressure capabilities from full flow to virtually zero flow. During the production cycle, instead of pumping the hydraulic fluid back to the reservoir tank, the oil is pumped when it is needed. From Figure 6, [4] it shows that the slope for the IMM without the ITDT pump is 1 kWh/minute whereas with the ITDI retrofit it is 0.5 kWh/ minute. This translates to approximately 50% energy savings. Similarly, Figure 7 [4]shows the demand comparison between the IMM with and without ITDT retrofit, and the estimated demand savings is approximately 46%.[4]

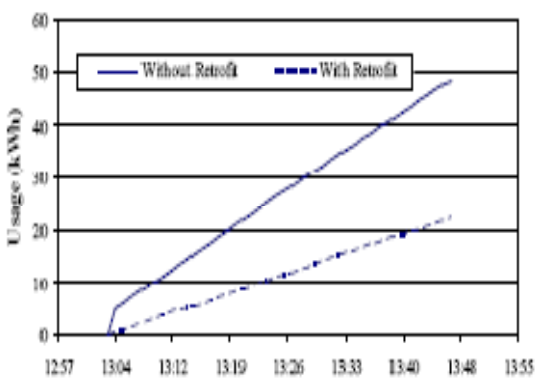

Figure 6: Comparative Energy Usage of Hydraulic IMM with and without ITDT Pumps

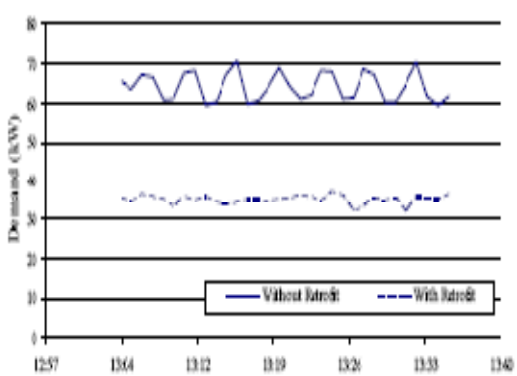

Figure 7: Comparative Demand of Hydraulic IMM with and without ITDT Pumps

5. Install waterside economizer to use free cooling during the winter: When the ambient temperature falls below chilled water return temperature during the winter, free cooling can be activated using water side economizer. Before going to the chiller, return water temperature is diverted through the water side economizer. The economizer cools the water and reduces the load on the chiller and the energy consumed by the chiller compressors. This measure provides considerable amount of energy savings and a quick payback.

6. Variable speed drive on chilled water pump: This is a popular retrofit measure for the process chilled water pump. A VSD modulates the speed of the pump based on the chilled water tank temperature that supplies water to molds and barrels. This VSD retrofit measure saves substantial amount of energy with quick pay back. One of our recent measurement verification studies on this measure estimated a 33%[8] energy savings as compared to a constant speed pump. The simple payback for this measure, prior to the incentive, was a little over two years.

7. Optimize facility compressed air system: Compressed air is considered as an expensive energy stream. One of the easiest methods to save energy when using compressed air is to minimize air demand and optimize supply. Following are some energy efficiency recommendations for the compressed air system in a polymer manufacturing facility.

- Repair compressed air leaks
- Replace non-cyclic air dryer with thermal mass cyclic dryer
- Reduce the compressor operating pressure to facility's required pressure
- Install intelligent controller to control and stage multiple air compressors
- Use of ambient air for compressors

All of these above energy efficiency measures save a significant amount of energy for compressed air systems and offer a quick payback.

Apart from the above energy efficiency measures, there are other energy efficiency opportunities that can be implemented in extrusion, blow molding, rotational molding process in plastic manufacturing. Extrusion uses plastic pellets that are fed into an extruder through the hopper and continuously fed to a heated barrel and carried along by a rotary screw.

[8] Energy savings are based on DNV KEMA's monitored kW data

The main components responsible for energy consumption in the extrusion process are the motors, drives, heaters, cooling system and lighting system. Popular energy efficiency measures implemented in the extrusion process are optimization of air compressors, barrel insulation, VFDs on chilled water pumps and high- efficiency lighting. Similarly, various energy efficient strategies can be implemented in blow molding and rota-molding process to reduce energy consumption.

Although there are many energy efficiency opportunities available in plastic manufacturing industry, the implementation of these opportunities face certain market barriers. The section below discusses various market barriers and the mitigation strategies to overcome them.

POTENTIAL MARKET BARRIERS

Although implementation of energy efficiency strategies can offer substantial energy savings and reasonable payback in number of cases, the penetration of these energy efficiency measures into the plastic manufacturing market has been low to date. From discussions with personnel in plastic manufacturing facilities, we found that there are many reasons why plastic manufacturers are reluctant to implement energy efficiency measures.
This suggests that market barriers exist. Market barriers may take many forms such as high capital cost, information availability, lack of technical expertise and more. In this section we will discuss the primary market barriers that exist in the plastic manufacturing industry.

Limited capital availability forces energy efficiency investment to compete with other investment priorities. This is particularly true for smaller plastic manufacturers with cash flow constraints. Also, in smaller companies, machines are older, making it less suitable for retrofit measure. Small manufacturers tend to continue operating the equipment, until its end of life.

Another factor that impacts capital availability for implementing energy efficiency measures is energy price fluctuation. Drastic or even slight increases in the cost of energy can make customers disinterested in energy efficiency. Volatility in energy prices creates an uncertainty, which in turn alters the profitability on investment. These uncertainties lead to higher perceived risks and make the investment criteria more stringent. Uncertainties also impact the measure implementation hurdle rate.

The decision making process in manufacturing companies is a function of its rules of procedure, business climate, corporate culture, the manger's personality and perception of the company's energy efficiency. [5] Energy efficiency as means to reduce operating cost is not a high priority in many plastic manufacturing facilities because energy cost is approximately 3 to 5% [9]of their total operating cost of the plant.

A recent interview with an Ohio-based plastics manufacturer revealed the details of the company's the energy efficiency implementation policies. According to him, the firm's management does care about energy efficiency – in the plastics manufacturing business the energy portfolio cost is minimal in comparison to the other operating costs. Management tends to be motivated in investing in other areas because they want to have a quick return on the investment. The plant manager in Ohio also mentioned that, if the energy efficiency measure has a simple payback of less than one year, then management promptly decides to implement the measure. The facility manager also indicated that any energy efficiency recommendation that has a payback of more than two years would never be implemented. This analysis demonstrates the need for a better understanding of the benefit of energy efficiency during the decision making process.

Lack of skilled technical personnel is another important market barrier in the implementation of energy efficiency measures. Plastic manufacturing is a complex process. It uses expensive multifaceted equipment such as injection molders, blow molders, extruders and ancillary equipment such as air compressors, chillers, cooling towers and other energy intensive mechanical equipment. Selecting and installing energy efficiency equipment requires in-house trained technical personnel who have the knowledge to identify the inefficiencies and the expertise to identify energy efficiency opportunities to reduce the overall energy consumption. In most facilities, there are often trained technical personnel – most of whom are busy in maintaining production to devote time to energy efficiency. Many plastics manufacturing companies have a hierarchy of environmental or energy managers that may lead to less attention of energy efficiency and a reduction in the availability of resources to implement new energy efficiency measures. [5]

Another barrier is the lack of measurement capabilities that make energy efficiency measures

[9] Obtained from a plastic manufacturer in Ohio

invisible. It then becomes difficult to demonstrate the energy savings and to quantify their impacts. It has been said that you cannot manage what you cannot measure. Many plastic manufacturers do not have the capabilities to measure and record the energy usage of their process equipment. Without metering data, it is difficult to determine how much energy has actually been saved. A lack of measurement and verification can increase the uncertainty in energy savings by approximately ±40%, [6] which in turn enhances the uncertainties on the energy cost reduction and throws the return on investment way off from the actual estimate. This is a major hurdle in implementing energy efficiency measures.

MITIGATION STRATEGIES OF MARKET BARRIERS

This section discusses various strategies of mitigating potential market barriers in implementing energy efficiency measures among plastics manufacturers. Various Strategies have been used to overcome the market barriers and varying success rates has been achieved by implementing these strategies.

Most of the companies have financial constraints in implementing energy efficiency options. Therefore, energy efficiency options with more than two years payback are rarely implemented. While some energy efficiency options provide a huge savings with shorter payback, other options require high capital, and therefore, a longer payback period. This poses a perceived barrier that stops plastic manufacturers from implementing energy efficiency opportunities. Fortunately, financial assistance has been extended by most of the utilities in the U.S., which provides monetary incentive to customers for implementing energy efficiency projects. These financial benefits can be as high as 50% of the project cost.

Lack of knowledge has been perceived as another important market barrier in implementing energy efficiency opportunities in the plastics manufacturing industry. In most plastics manufacturing facilities, management is focused on maximizing production output rather than on producing more efficiently. Loss of production means reduction in profit. As a result, it can be difficult to convince management to authorize energy assessment and implement energy efficiency measures unless management sees the energy efficiency investment as cost savings.

Additionally, some plastics manufacturers perceive energy efficiency installations as a threat. They believe that the new energy efficient machine or retrofit might have a negative impact on their production. To mitigate this market barrier, utilities and government agencies all across the U.S. have been proactively implementing various strategies in creating awareness for top management, training of utility account representatives and external facilitators on how to convince and assist management. Success stories or case studies, demonstration projects, energy awareness workshops and media campaigns are all channels to build awareness. Also, reporting facility's energy use has been shown as an effective means of raising management awareness of internal energy consumption trends where benchmarking energy use provides a means to compare the energy use of one facility to that of others producing the same product. [5]

Programs that promote technical training and demonstration of energy efficiency technologies have been successful in training facility personnel. Providing these technical training and organizing energy awareness workshops not only enhances their energy expertise, but also effective in helping them identify energy efficiency opportunities in the facility.

Lack of measurement is seen as one of the important barriers for quantification of energy savings in a plastic manufacturing plant. Utilities, government agencies and program implementers and energy mangers are taking various steps to overcome this market barrier. The first step in addressing the barrier is to understand where, when, why and how energy is used in the plant. The next step is to identify key energy performance parameters then monitor them to assess the current energy consumption and identify the inefficiencies in the plant. Finally, the identified inefficiencies are addressed by implementing various energy efficiency strategies.

For example: In an injection molding facility, there are various end-use equipment such as process machines, HVAC, air compressors, lighting and ancillary equipment. So, the first step is to identify energy key performance parameters for each of the above end use. In case of process machines which are basically injection molding machines, the parameters that can be monitored are machine power draw, cycle time, downtime of the machine, product throughput and various other performance parameters. These parameters are then studied and either machine optimization or energy efficiency retrofit for the machine is recommended to reduce the energy consumption. The process machine

operations have an impact on ancillary equipment as well. If the process machines (injection molding machines) are optimized or retrofitted with energy efficiency strategies, then the ancillary equipment such as cooling system and air compressor would not have to work as hard as it did before the machine energy efficiency optimization. That means, there are opportunities to reduce energy consumption of the air compressor and as well as the cooling equipment. So, measurement of energy has a very positive impact on the implementation of the energy efficiency measures in the plastic manufacturing plants. Additionally, not only does the measurement provide visibility of energy savings opportunities, but also it gives the precise estimate of energy savings which helps the customer to estimate the annual cost savings and paybacks associated with energy efficiency strategies. This gives the customer the ability to plan or prioritize the implementation of energy efficiency in their facility.

SUMMARY AND CONCLUSIONS

Plastic manufacturing is an energy intensive industry. Focusing on energy efficiency and investing in energy efficient technologies can make a substantial impact on environment and economy. This paper presents various energy savings measures that can be implemented in plastic manufacturing facilities to reduce their energy consumption. A study performed in the year 2005 by Industrial Assessment Centers on 11 plastic manufacturing plants estimated an average 9.7% [1] of energy savings by implementing various energy efficient measures. This projection can make an overall the US plastic and resin manufacturers to save approximately 103.79 trillion Btu annually. Although there are tremendous opportunities available in plastic manufacturing to reduce energy consumption, these opportunities face barriers in implementation of these measures. Barriers to these energy efficiency improvements may take many forms and can be determined by various factors such as decision making process, lack of energy efficiency expertise, limited capital availability and lack of ability to quantify the measures. Various mitigation strategies were placed to overcome these barriers and to improve the implementation of the energy efficiency strategies. We have discussed some methods to improve the implementation rate in plastic industry, specifically mitigation of decision making barrier. Decision making is perceived as one of the important barriers in implementation of the energy efficiency measures in plastic manufacturing. But, utilities and government agencies are using various mitigation strategies overcome this important barrier. Some of the mitigation strategies include creating awareness among top management, training of utility account representatives and external facilitators on how to convince and assist management; success stories/case studies, demonstration project, energy awareness workshops, media campaign, and inclusion in school curriculum. Another mitigation strategy that has been very successful is the raising management's awareness of internal energy consumption and comparing their energy consumption to the benchmarking energy use of one facility to that of others producing the similar product. Apart from mitigating the decision making barrier, there are various mitigation strategies placed that are useful in overcoming other market barriers.

BIOGRAPHIES

Amit Kanungo is an Engineering Consultant at DNV KEMA. Mr. Kanungo has focused his skills on providing engineering insight to a wide variety of custom energy efficiency projects. Amit has been actively involved as a lead evaluation consultant to California Public Utility Commission's state wide non-residential custom evaluation program. His role includes technical consulting, planning evaluation activities, conducting site visits, analyzing data and providing high level technical insight to the custom program. Amit is also involved in AEP Ohio's Energy Implementation program. His work has included analyzing energy-efficiency measures in various industries, such as wastewater treatment, plastic manufacturing facilities, food manufacturing, industrial refrigeration and other commercial and industrial facilities. Mr. Kanungo is experienced in isolating and assessing interactive energy savings as well as diversified coincident demand impacts from complex custom projects. He has utilized his knowledge of non-residential energy codes and green building design and construction requirements to evaluate new construction projects. Mr. Kanungo has performed building energy simulations on a variety of building and HVAC system types (including commercial and industrial facilities), using energy simulation programs. He has also conducted impact evaluations by applying engineering methodology and energy simulation tools to evaluate facilities, to evaluate building and equipment performance and energy savings impacts from the energy efficiency measures implemented. Mr. Kanungo has presented various technical papers reflecting different energy efficiency technologies and methods. He holds a Master's degree in Electrical Engineering from California State University, San Francisco.

Joo Ching Yong is an energy consultant at DNV KEMA. Ms. Yong specializes in energy analysis, program implementation, and quantitative research. She has conducted energy audits and implemented non-residential programs. She has also performed project coordination, engineering analysis, performance monitoring of systems, building optimization assessment studies for commercial facilities, and other related work. She also developed project interview guidelines, application forms; energy savings work papers, and marketing materials related to utility incentive implementation programs. Ms. Yong holds a Master of Science degree in Industrial Engineering, with a concentration in Energy Management, from Oklahoma State University at Stillwater, Oklahoma. She holds a Bachelor of Science degree in Industrial Engineering from Oklahoma State University at Stillwater, Oklahoma.

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6. California Evaluation Framework, Uncertainty Analysis, Page166, Table 7.7

MANUFACTURING ENERGY AND CARBON FOOTPRINTS

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ABSTRACT

Significant opportunities exist for improving energy efficiency in U.S. manufacturing. A first step in realizing these opportunities is to identify how industry is using energy. Where does it come from? What form is it in? Where is it used? How much is lost? Answering these questions is the focus of this paper and the analysis described herein.

Manufacturing energy and carbon footprints map energy consumption and losses, as well as greenhouse gas emissions, for the fifteen most energy intensive manufacturing sectors, and for the entire U.S. manufacturing sector. Analysts and decision-makers utilize the footprints to better understand the distribution of energy use in energy-intensive industries and the accompanying energy losses. The footprints provide a benchmark from which to calculate the benefits of improving energy efficiency and for prioritizing opportunity analysis. A breakdown of energy consumption by energy type and end use allows for comparison both within and across sectors.

MANUSCRIPT

INTRODUCTION

The Manufacturing Energy and Carbon Footprints provide a reliable reference for industrial energy use characteristics. The footprints were prepared for the U.S. Department of Energy (DOE) Advanced Manufacturing Office (AMO), formerly the Industrial Technologies Program. Sixteen two-page footprints representing the most energy intensive manufacturing sectors have been published on the AMO website and a comprehensive presentation of the results is soon to be available in the form of a report titled *Manufacturing Energy Use and Loss and Emissions Analysis*. The report will be produced by Energetics Incorporated and published by Oak Ridge National Laboratory.

The footprints serve as a map of manufacturing energy use and loss and associated greenhouse gas emissions from fuel, electricity and steam use. Footprints have been published for the following fifteen energy-intensive sectors representing 94% of manufacturing energy use (listed in alphabetical order): aluminum, cement, chemicals, computers and electronics, fabricated metals, food and beverage, forest products, foundries, glass, machinery, petroleum refining, plastics, iron and steel, textiles, and transportation. A sixteenth footprint was created to represent energy use for all of U.S. manufacturing, which in 2006 was close to 22 quadrillion British Thermal Units (Btus).

Two footprints are provided for each sector, one showing a primary (source) energy perspective and a second showing onsite energy by end use. Onsite end uses of energy are grouped in the footprint as either generation end uses, process end uses, or nonprocess end uses. Providing a breakdown of energy type by end use area allows for a comparison of energy use and emissions sources both within and across sectors.

ENERGY EFFICIENCY IN MANUFACTURING

The U.S. manufacturing sector depends heavily on energy resources to provide fuel, power and steam for the conversion of raw materials into usable products. The efficiency of energy use, as well as the cost and availability of energy, consequently have a substantial impact on the competitiveness and economic health of U.S. manufacturers. More-efficient use of energy lowers production costs, conserves limited energy resources, and increases productivity. The more-efficient use of energy also has positive impacts on the environment, including reduced emissions of greenhouse gases and air pollutants.

Energy efficiency varies dramatically across manufacturing sectors, and across the various process and non-process end uses within each sector. The physical and chemical parameters of a process, as well as equipment design, age, and operating and maintenance practices, can lead to real-world performance below the ideal efficiency. Less-than-optimal energy efficiency means that some of the input energy is lost either mechanically or as waste heat. In the manufacturing sector, energy

losses amount to several quadrillion Btus and billions of dollars in energy costs each year.

It is clear that increasing the efficiency of energy use could result in substantial benefits to both industry and the nation. Unfortunately, the sheer complexity of the thousands of processes used in the manufacturing sector makes this a daunting task. There are, however, significant opportunities to address energy efficiency in the common energy systems that are used across manufacturing, such as onsite power systems, fired heaters, boilers, pumps, HVAC equipment and others. A first step in realizing these opportunities is to identify how industry is using energy. Where does it come from? What form is it in? Where is it used? How much is lost? Answering these questions for U.S. manufacturing sectors is the focus of the footprint presented here.

INTERPRETING THE FOOTPRINTS

Each footprint consists of two figures; the first figure offers an overview of the sector's total **primary energy** flow including offsite energy and losses, while the second figure presents a more detailed breakdown of the **onsite energy** flow. The term "Total" in the footprints refers to the total sum of offsite and onsite values. Energy use is shown as input and output flow lines to the various pathway stages. Energy values are shown by energy type in the color-coded flow lines and carbon emissions are shown by end use.

The footprint color legend is provided in Figure 1; dark gray = all energy, yellow = fuel, dark red = electricity, and blue = steam. Energy losses are represented as wavy red arrows. Carbon emissions appear in the boxes along the bottom of each pathway stage. Offsite, onsite, and total carbon emissions are distinguished by color as shown in the legend; dark brown = offsite carbon, light brown = onsite carbon, and medium brown = total carbon (offsite + onsite).

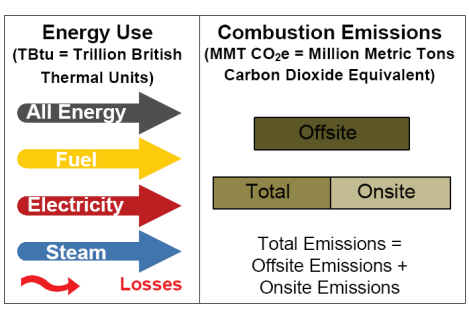

Figure 1. Footprint Color Legend

The footprint pathway captures both energy supply and demand. On the supply side, the footprints provide details on energy purchases and transfers in to a plant site, and onsite generation of steam and electricity. Byproduct fuels, such as black liquor and wood byproducts in pulp and paper mills and waste gas from petroleum refineries, are included in the fuel supply. On the demand side, the footprints illustrate the end use of energy within a given sector, from process energy uses such as heaters and motors, to nonprocess uses such as HVAC and lighting. The footprints also identify where energy is lost due to generation and distribution losses and system inefficiencies, both inside and outside the plant boundary. Losses are critical, as they represent immediate opportunities to improve efficiency and reduce energy consumption through best energy management practices and technologies.

In the primary energy footprint figure the energy supply chain begins with the fuel, electricity, and steam supplied to the plant boundary from offsite sources (power plants, fuel and gas distributors, etc.). The primary energy footprint for all of U.S. manufacturing is shown in Figure 2.

In the onsite energy footprint figure the energy demand is shown by energy type and end use. The onsite energy that reaches the plant boundary is used either indirectly for onsite generation or directly for process and nonprocess end uses. The onsite energy footprint for all of U.S. manufacturing is shown in Figure 3.

Onsite energy generation, which consists of conventional boilers, combined heat and power (CHP)/cogeneration systems, and other electricity generation such as renewable energy sources, contributes to the electricity and steam demands of process and nonprocess end uses. Often, onsite generation of energy creates more energy than is needed at the plant site. When this occurs, the excess energy is exported offsite to the local grid or other nearby plants. Total primary and onsite energy use values are based on net electricity and do not include exported electricity. Exported steam is accounted for in the MECS net steam data, and thus not shown in the footprint.

Process energy systems consist of the equipment necessary for process heating (e.g., kilns, ovens, furnaces, strip heaters), process cooling and refrigeration, electro-chemical processes (e.g., reduction processes), machine drive (e.g., motors

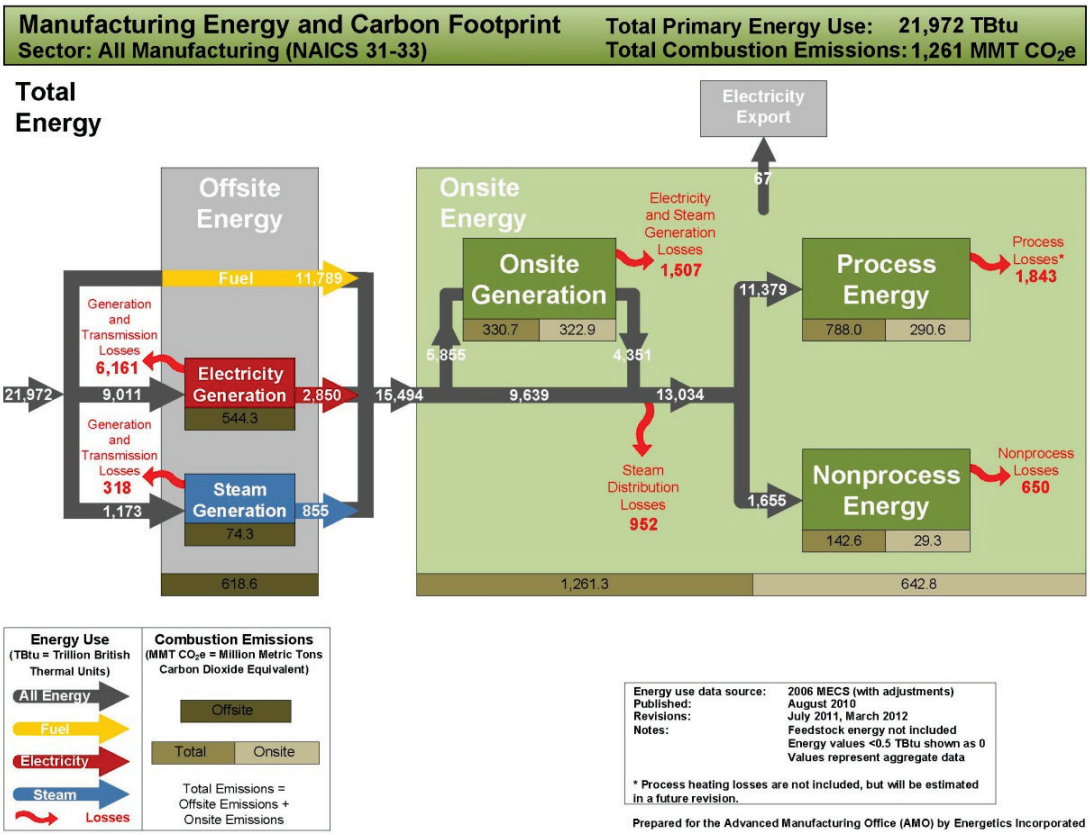

Figure 2. Primary Energy Footprint for All U.S. Manufacturing, NAICS 31-33, Year 2006

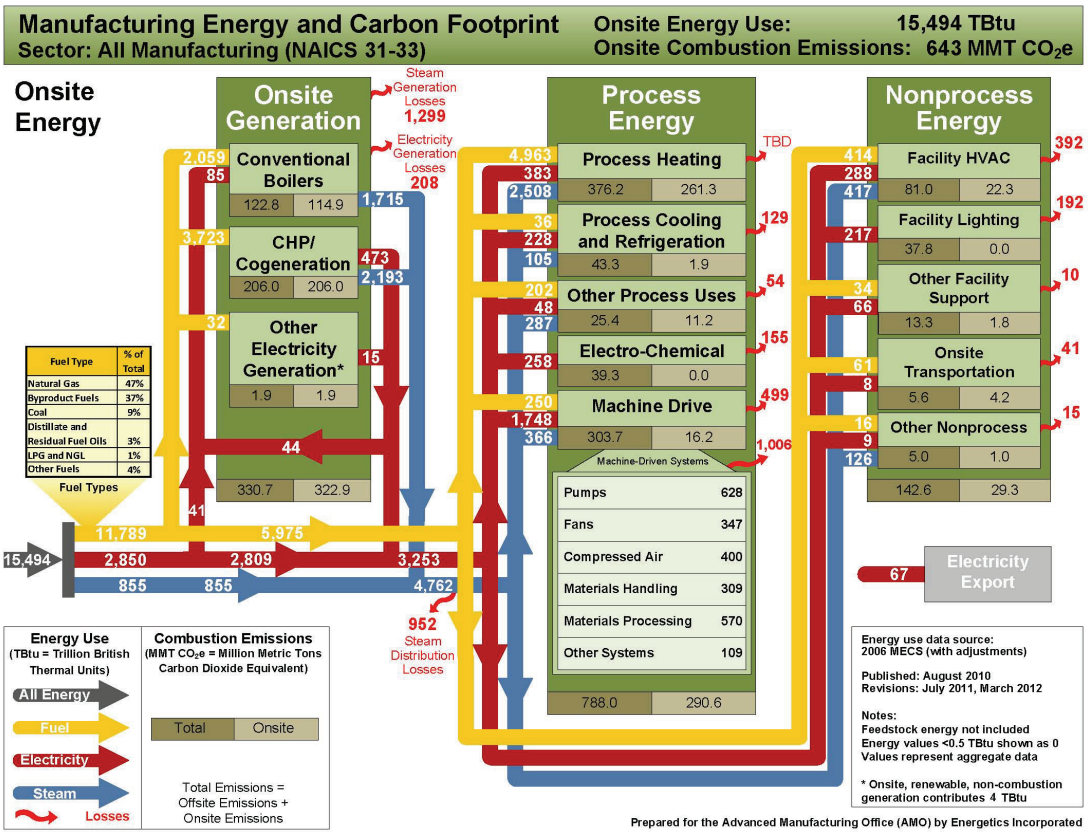

Figure 3. Onsite Energy Footprint for All U.S. Manufacturing, NAICS 31-33, Year 2006

and pumps associated with process equipment), and other direct process uses. Another step in the energy pathway is the energy that is distributed to nonprocess end uses. This involves the use of energy for facility HVAC, facility lighting, other facility support (e.g., water heating and office equipment), onsite transportation, and other nonprocess use.

Energy losses occur along the entire energy supply and demand pathway and are estimated in the footprint analysis. Energy is lost in offsite and onsite power and steam generation systems and in process and nonprocess end uses due to equipment inefficiencies and mechanical and thermal limitations. In some cases, heat-generating processes are not optimally located near heat sinks, and it may be economically impractical to recover the excess energy. In other batch process cases energy is lost because it cannot be stored during off-peak times. Energy losses also occur in transmission systems distributing energy both to and within the plant. All of these estimated energy losses vary greatly by industry and by facility.

SCOPE OF THE FOOTPRINTS

The footprint analysis looks at a large subset of U.S. manufacturing, with the objective of capturing the bulk share of energy consumption and carbon emissions. In Table 1 the fifteen manufacturing sectors selected for footprint analysis are listed in alphabetical order. A sixteenth footprint represents all of U.S. manufacturing energy use.

Manufacturing sectors were selected based on their relative energy-intensities, contribution to the economy, and relative importance to energy efficiency programs. Manufacturing sectors are most commonly classified by North American Industry Classification System (NAICS) code, as defined by the U.S. Census Bureau. Many of the footprint sectors selected for study are represented by a combination of NAICS subsectors (e.g., Wood Products and Paper Products are combined under the heading Forest Products). When combined, the fifteen individual sectors shown in Table 1 contribute ninety-four percent of overall manufacturing primary energy use.

Manufacturing Sectors Selected for Footprint Analysis*	
All Manufacturing NAICS 31-33	**Foundries** NAICS 3315
Alumina and Aluminum NAICS 3313	**Glass and Glass Products** NAICS 3272 Glass and Glass Products NAICS 327993 Mineral Wool
Cement NAICS 327310	**Iron and Steel** NAICS 3311 Iron and Steel Mills and Ferroalloys NAICS 3312 Steel Products
Chemicals NAICS 325	**Machinery** NAICS 333
Computers, Electronics, Electrical Equipment, and Appliances NAICS 334 Computer and Electronic Products NAICS 335 Electrical Equipment, Appliances	**Petroleum Refining** NAICS 324110
Fabricated Metals NAICS 332	**Plastics and Rubber Products** NAICS 326
Food and Beverage NAICS 311 Food NAICS 312 Beverage and Tobacco Products	**Textiles** NAICS 313 Textile Mills NAICS 314 Textile Product Mills NAICS 315 Apparel NAICS 316 Leather and Allied Products
Forest Products NAICS 321 Wood Products NAICS 322 Paper	**Transportation Equipment** NAICS 336
* Listed in alphabetical order	

Table 1. Manufacturing Sectors Selected for Footprint Analysis

ENERGY MODEL APPROACH

The energy and carbon values portrayed in the footprint are the result of a complex analysis effort. Energy-use statistics, relevant emissions guidelines, and industry expertise were all utilized to devise an analytical model for detailing sector-specific energy use and loss and associated carbon emissions. Energetics compiled a network of spreadsheets representing various energy use and emissions calculations and efficiency statistics, and bundled these in to a model that is linked to a software diagramming tool. Energy use statistics were obtained from DOE, Energy Information Administration (EIA)-published MECS results Manufacturing Energy Consumption Survey, for survey year 2006, when the survey was last completed [3].

Manufacturing Energy Consumption Survey

The MECS is a mandatory self-administered nationally representative sample survey of approximately 15,500 U.S. manufacturing establishments. The survey is conducted by EIA every four years, and the U.S. Census Bureau, with guidance from EIA, selects the manufacturing population using the North American Industry Classification System (NAICS). The majority of the survey data consists of energy consumption (both fuel and feedstock), energy purchases and transfers, onsite energy produced and generated, and for the most widely used energy sources, breakouts of end use and fuel switching capacity. The MECS survey data also consists of energy pricing, ratios of fuel consumption, energy management activities, and floor space.

Adjustments, References, and Estimates

In order to complete an accurate balance of manufacturing energy use, several adjustments were applied to the MECS data tables to account for withheld data or to avoid double-counting. In addition, some assumptions were introduced when estimating energy losses and steam allocation. ***As a result, the energy use and loss values in the footprints do not directly represent MECS data, and should not be cited as MECS output.***

The electrical end use distribution to machine driven systems was obtained from the 2002 Oak Ridge National Laboratory (ORNL) study, *U.S. Industrial Electric Motor Systems Market Opportunities Assessment* [5]. Both the Environmental Protection Agency's (EPA) *Mandatory Greenhouse Gas Reporting Rule* [2] and the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* [1] were referenced in formulating the methodology and emission factors used for calculating greenhouse gas (GHG) emissions in this report, which include combustion-related emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The combustion emissions reported in the footprints are carbon dioxide-equivalent (CO_2e) GHG emissions.

A thorough literature search and peer review was conducted in arriving at the estimates used in the footprint analysis model. Offsite and onsite generation and transmission losses and CHP efficiency estimates are based on EIA data. Onsite generation and distribution losses, and process and nonprocess end use losses are drawn from published references and discussions with industry and process experts. Energy loss estimates are highly dependent on specific operating equipment and conditions and vary greatly within and across manufacturing sectors. The values shown in the footprint represent aggregate data and are not representative of any one particular plant.

Peer Review

Multiple rounds of review have taken place in finalizing the Manufacturing Energy and Carbon Footprints, including review and input from DOE AMO, ORNL, EIA, and representatives from various industry organizations and associations. A full list of references will be made available in the *Manufacturing Energy Use and Loss and Emissions Analysis* report.

As a result of the extensive review process it was determined that two areas of the footprint analysis deserved further peer review: 1) estimation of energy loss from process heating end use (to include system and exhaust losses), and 2) estimation of steam allocation to process and nonprocess end uses (steam end use is not provided in MECS). In the first months of 2012 two peer review committees were formed, a Steam End Use Working Group and a Process Heating Energy Loss Working Group. As a result of these continuing peer review efforts, updates to the footprints will be published on the AMO website.

Steam End Use Working Group

Representatives from seven industrial organizations with hands-on knowledge of manufacturing steam use met on four separate occasions to determine an acceptable approach

for estimating steam allocation to the MECS-defined end uses. Additional analysis took place between meetings. The industry group, led by a representative from Spirax Sarco, conducted an industry survey with over 80 industry respondents contributing site-based steam use estimates. The working group reached consensus on steam allocation by sector. In conclusion, it was determined that combined offsite steam (purchased or transferred in) and onsite generated steam was allocated to end uses as follows for All Manufacturing: process heating 66%, facility HVAC 11%, machine driven equipment 10%, other process uses 8%, process cooling and refrigeration 3%, and other facility uses 3%. A white paper will be published summarizing the scope and results of the Steam End Use Working Group.

Process Heating Loss Working Group

In earlier versions of the footprints, process heating energy loss, specifically exhaust loss, was not estimated. System loss and especially exhaust loss varies widely depending on the process heating equipment and application. Representatives from nineteen industrial organizations with interest in process heating energy management have gathered on two separate occasions to determine an acceptable approach for estimating process heating energy loss by sector. This peer review effort is unfinished at the time of publishing this paper. A white paper will be published at the conclusion of the peer review effort summarizing the scope and results of the Process Heating Loss Working Group.

ENERGY USE AND LOSS ANALYSIS

The energy footprint model developed by Energetics streamlines the MECS data and completes a representative balance of manufacturing energy use. The two-page footprints provide a helpful quick reference for energy use and loss and associated carbon emissions. The data output from the footprints has been further analyzed in the *Manufacturing Energy Use and Loss and Emissions Analysis* report. This report is in draft format and will be published on the AMO website at the conclusion of the Process Heating Loss Working Group effort. Some informative tables and figures from the report are provided in this paper as example.

In the first example from the *Manufacturing Energy Use and Loss and Emissions Analysis* report, Table 2 lists the total primary energy use and onsite energy use (in units of trillion Btu, TBtu) for the sixteen footprints studied. The values in the table represent energy use in the year 2006, the most recent survey year, and the sectors are listed by order of primary energy use. The table also shows each sector's percentage of primary energy use and the percentage of primary energy use that is consumed onsite.

Total primary energy use is a value that is calculated in the footprint model, it is not directly provided in the MECS data set. Primary energy use is calculated as the sum of total fuel consumption (from MECS Table 5.2), offsite electricity generation and transmissions loss, and offsite steam generation and transmission loss. This calculation is shown in Equation 1.

Primary energy = fuel consumption + offsite electricity loss + offsite steam loss

Equation (1)

Offsite electricity generation and transmission loss is calculated as the energy input to offsite electricity generation less the net offsite electricity output (from MECS Table 5.2). Energy input is estimated using a grid efficiency factor of 31.6% for year 2006 [4].

Offsite steam generation and transmission loss is calculated as the energy input to offsite steam generation less the net offsite steam output (from MECS Table 1.5). Energy input is estimated assuming 81% efficiency of offsite steam generation and 10% loss during steam transmission to the plant boundary [6].

Onsite energy use is similarly a value that is calculated in the footprint model, and not directly provided in the MECS data set. Onsite energy is calculated as the sum of offsite electricity, offsite steam, and offsite fossil fuel; these values are also estimated in the footprint model. This calculation is shown in Equation 2.

Onsite energy = offsite electricity + offsite steam + offsite fuel

Equation (2)

Given that the energy losses are higher for offsite electricity generation than for offsite steam generation, those sectors with proportionally greater electricity usage (e.g., computers and electronics) have higher offsite loss, and therefore the percentage of primary energy consumed onsite is lower.

Manufacturing Sector	Total Primary Energy Use, TBtu *	Percentage of Primary U.S. Manufacturing Energy Use *	Onsite Energy Use, TBtu *	Percentage of Primary Energy Consumed Onsite *
Chemicals	4,519	21%	3,195	71%
Forest Products	3,553	16%	2,799	79%
Petroleum Refining	3,546	16%	3,231	91%
Food and Beverage	1,935	9%	1,295	67%
Iron and Steel	1,481	7%	1,043	70%
Transportation Equipment	904	4%	480	53%
Plastics and Rubber Products	729	3%	336	46%
Fabricated Metals	706	3%	397	56%
Alumina and Aluminum	603	3%	273	45%
Computers and Electronics	527	2%	228	43%
Textiles	472	2%	265	56%
Cement	471	2%	382	81%
Glass and Glass Products	466	2%	330	71%
Machinery	444	2%	204	46%
Foundries	281	1%	158	56%
All Manufacturing	21,972	100%	15,494	71%

* The values in this table are not directly obtained from published MECS data; they are obtained from the energy footprint model developed by Energetics Incorporated which relies on MECS input data.

Table 2. Primary and Onsite Energy Use for 16 Footprint Sectors (Including Percentage of U.S. Primary Energy Use and Percentage of Primary Energy Use Consumed Onsite), Year 2006

In Figure 4, it is shown that the U.S. manufacturing sector consumed 21,972 TBtu of primary energy in 2006. Fuel that is used directly by process and nonprocess end uses accounts for 27%; natural gas accounts for over half this consumption. Steam generation is the next largest category of primary energy, consuming 29%. Onsite steam and associated losses contribute the majority (84%) of primary steam energy use, offsite steam and associated losses contributes only 16%.

Electricity generation is the largest category of primary energy use—comprising 44% of primary energy. Over 93% of primary electricity energy use is from offsite generation and associated losses. Electricity generation and end use values for All Manufacturing are shown in more detail in Figure 5.

Primary energy use figures, similar to Figures 4 and 5 are provided for the most energy intensive sectors in the *Manufacturing Energy Use and Loss and Emissions Analysis* report. Similar pie chart figures are also provided for onsite energy use, including estimation of "applied" end use, which accounts for both generation and end uses losses.

A final example from the *Manufacturing Energy Use and Loss and Emissions Analysis* report is the GHG emissions by energy type for U.S. manufacturing shown in Figure 6.

NEXT STEPS

The manufacturing energy and carbon footprint analysis is close to complete. Upon completion of the current process heating peer review effort, final revised 2006 footprints will be published on the AMO website. EIA has recently announced the release of preliminary MECS 2010 data. The footprint model will be updated with this new data source as soon as it is available and updated 2010 footprints will be published accordingly.

The *Manufacturing Energy Use and Loss and Emissions Analysis* report will be finalized to show process heating loss values and will also be published on the AMO website. Finally, two white papers will be prepared summarizing the scope and results of the Steam End Use and Process Heating Loss Working Groups. These white papers will appear as appendices in the *Manufacturing Energy Use and Loss and Emissions Analysis* report.

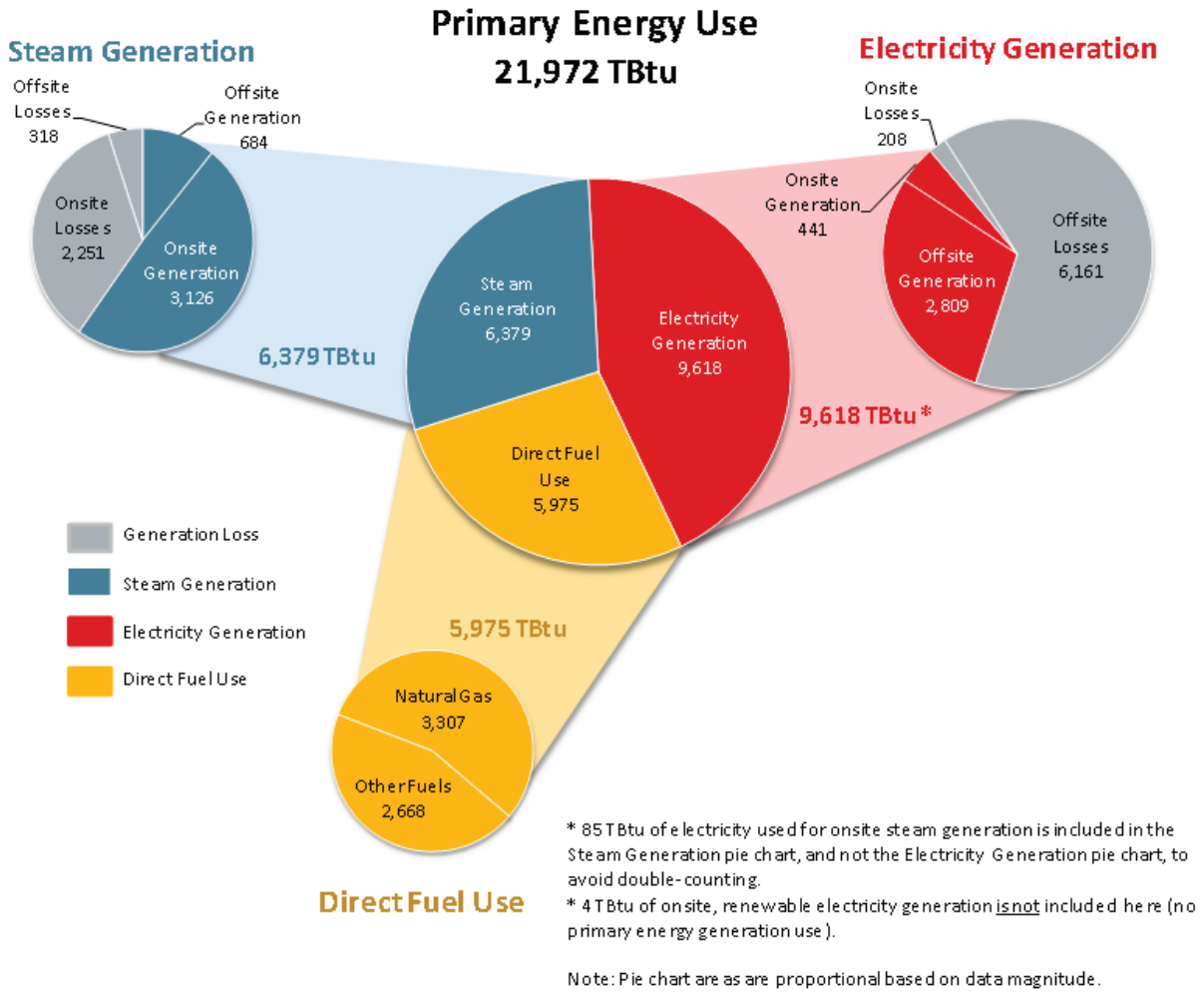

Figure 4. Primary Energy Use by Energy Type in U.S. Manufacturing

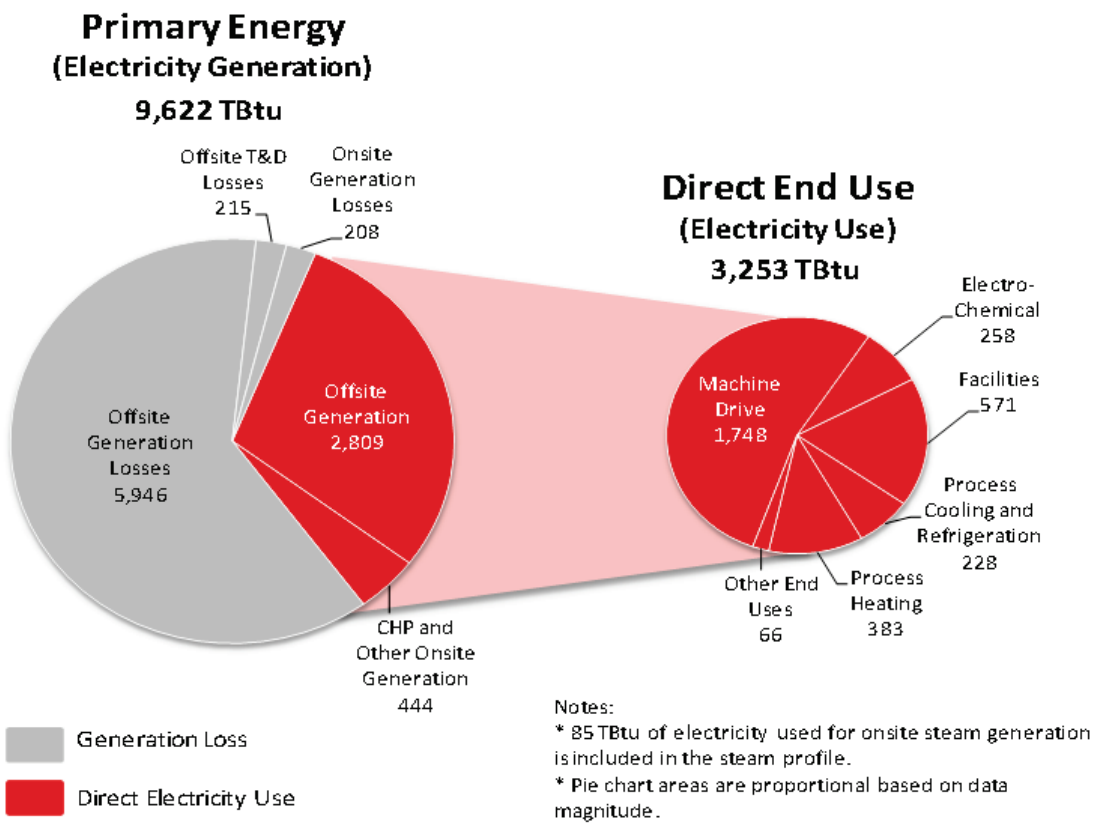

Figure 5. Electricity Generation and End Use in U.S. Manufacturing

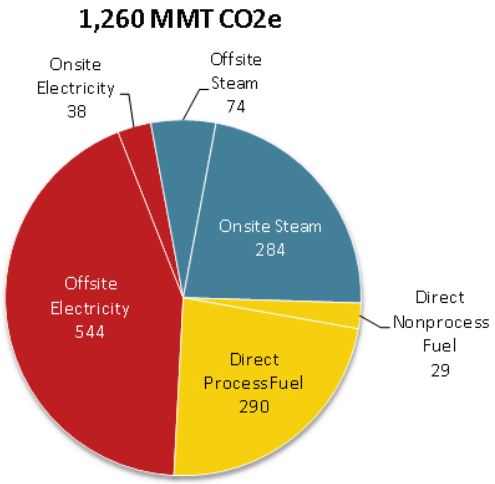

Figure 6. Total GHG Emissions by Energy Type in U.S. Manufacturing

REFERENCES

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A Review of Emerging Energy-efficiency and CO_2 Emission-reduction Technologies for Cement and Concrete Production

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ABSTRACT

Globally, the cement industry accounts for approximately 5 percent of current man-made carbon dioxide (CO_2) emissions. Development of new energy-efficiency and CO_2 emission-reduction technologies and their deployment in the market will be key for the cement industry's mid- and long-term climate change mitigation strategies. This paper is an initial effort to compile the available information on process description, energy savings, environmental and other benefits, costs, commercialization status, and references for emerging technologies to reduce the cement industry's energy use and CO_2 emissions. This paper consolidates available information on eighteen emerging technologies for the cement industry, with the goal of providing engineers, researchers, investors, cement companies, policy makers, and other interested parties with easy access to a well-structured database of information on these technologies.

1. INTRODUCTION

The cement industry accounts for approximately 5 percent of current man-made carbon dioxide (CO_2) emissions worldwide (WBCSD/IEA 2009a). World cement demand and production are increasing; annual world cement production is expected to grow from approximately 2,540 million tonnes (Mt) in 2006 to between 3,680 Mt (low estimate) and 4,380 Mt (high estimate) in 2050. The largest share of this growth will take place in China, India, and other developing countries on the Asian continent (WBCSD 2009b). This significant increase in cement production is associated with a significant increase in the cement industry's absolute energy use and CO_2 emissions.

Many studies from around the world have identified sector-specific (e.g., Worrell et al. 2008; APP 2009; CSI/ECRA 2009) and cross-cutting (e.g., U.S. DOE AMO 2011) energy-efficiency technologies for the cement industry that have already been commercialized. However, information is scarce and scattered regarding emerging or advanced energy-efficiency and low-carbon technologies for the cement industry that have not yet been commercialized. This paper consolidates available information on emerging technologies for the cement industry with the goal of giving engineers, researchers, investors, cement companies, policy makers, and other interested parties easy access to a well-structured database of information on this topic.

We also have provided the commercialization status of each technology along with resources for further information. The commercialization status for each technology is as of the writing of this paper and uses the following categories:

- Research stage: the technology has been studied, but no prototype has been developed
- Development stage: the technology is being studied in the laboratory, and a prototype has been developed
- Pilot stage: the technology is being tested at an industrial-scale pilot plant
- Demonstration stage: the technology is being demonstrated and tested at the industrial scale in more than one plant but has not yet been commercially proven
- Semi-commercial stage: the technology is proven and is being commercialized but has a very small market share

2. EMERGING ENERGY-EFFICIENCY AND CO_2 EMISSION-REDUCTION TECHNOLOGIES

The subsections below describe emerging technologies to reduce energy consumption and CO_2 emissions in the different steps of the cement production process, as well as emerging alternative raw materials and products for the cement and concrete production.

2.1. Emerging Grinding Technologies

2.1.1. High-Activation Grinding

One strategy for conserving materials and reducing energy use in cement production is to increase the amounts of elements other than Portland cement in blended cement products. However, increased use of other elements can result in a final product that is slow to develop compressive strength. One solution that has been researched to improve compressive strength development is using high-energy milling to mechanically increase the reactivity of some of the blended constituents, i.e., fly ash and slag (Kumar et al. 2006). Mechanical activation or enhanced reactivity of fly ash or blast furnace slag in cement results from the combined effects of increased surface area and physiochemical changes produced by vibratory or attrition milling (Kumar et al. 2007).

The EMC Cement Company produces energetically modified cement (EMC) and pozzolana using a commercialized technology based on mechanical activation concepts. EMC's plant began operating near Jewett, Texas in September, 2004 with an initial production capacity of about 150,000 tonne/year, which can be increased to meet demand. Waste fly ash from a power plant is conveyed directly to the EMC production facility (EMC Cement 2011). Other Emerging Grinding Technologies are ultrasonic comminution and plasma comminution (Schneider et al. 2011; Schneider 2008).

2.2. Emerging Kiln Technologies

2.2.1. Fluidized Bed Kiln

A fluidized bed kiln (FBK) burns raw materials into powder with granules 1.5 to 2.5 millimeters (mm) in diameter. FBK uses a new technology known as granulation control/hot self-granulation (NEDO 2008), which agglutinates part of the raw material powder to form a core and attaches other raw material powder around the core. A FBK replaces the traditional rotary kiln with a stationary vertical cylindrical vessel (reactor) where the raw materials are calcined in a fluidized bed. An overflow at the top of the reactor regulates the transfer of clinker to the cooling zone. FBKs have improved heat recovery rates compared to conventional rotary kilns (burn to 1,400^{o}C and cool to 100°C in a two-stage cooler) (European Commission 2010).

The FBK's advantages are anticipated to be lower capital costs, lower operating temperatures, fewer NO_x emissions, lower overall energy use, and ability to accept a wide variety of fuels. However, it is difficult to scale up the current FBK demonstrations to the required 5,000 to 6,000 ton per day (tpd) clinker capacity (Worrell and Galitsky 2004). Early FBK technologies were not commercially successful because of high clinker recycling rates. Today, FBK development is in progress in Japan and the U.S. A FBK with a clinker capacity of more than 1,000 tpd was being erected in China in 2009 but it is not clear whether or not it is in operation now (CSI/ECRA 2009). Table 2 shows the energy and other benefits of this technology and its commercialization status.

2.3. Emerging Technologies for Alternative Raw Materials

Table 3 shows the energy, environmental and other benefits as well as commercialization status of emerging raw material technologies. The description of each technology is given below.

2.3.1. Use of Steel Slag as Raw Material for the Kiln - CemStar® Technology

For steel manufacturing, calcium oxide or lime (CaO) is added to molten steel at 1,650^{o} C to remove impurities such as silica, magnesium, aluminum, and other oxides. These impurities float to the top and are poured away as slag (Perkins 2000). The CemStar® process was first developed in 1994 by Texas Industries (Midlothian, Texas). This process uses electric arc furnace slag as input to the cement kiln in place of limestone (Worrell et al. 2008). During the kiln pyroprocess, ¾-inch- to 1-inch-diameter slag is added to the feed end of the kiln as a component of the raw material mix. Because of its lower melting point (1,260^{o} C to 1,316^{o} C), the slag does not require additional fuel in the kiln to form clinker with other raw feed components. Moreover, mineralizers already present in the slag help catalyze clinker formation. In addition, the exothermic reaction of converting dicalcium silicate into tricalcium silicate, which happens when slag is exposed to the high temperature, releases supplementary heat into kiln, resulting in even higher efficiency of the cement manufacturing process (Perkins 2000).

Table 1. Emerging grinding technology for the cement industry

Technology Name	Energy/Environment/Other Benefits	Commercial Status	References
High activation grinding	• No waste material; the grinding process does not pollute air or water. • Process is enclosed, with required dust protection features. • Energy consumption is 30 to 50 kWh per ton product. • For every tonne of clinker replaced by additives from mechanical activation grinding, the avoided energy uses are approximately: o thermal energy: 3.0 to 6.5 GJ/tonne clinker o electricity: 60 to 100 kWh/tonne clinker (European Commission 2010) [1]	Semi-commercial	Kumar et al. (2006, 2007, 2008); EMC Cement (2011); Schneider et al. (2011); Schneider (2008)

Table 2. Emerging kiln technology for the cement industry

Technology Name	Energy/Environment/Other Benefits/Costs	Commercial Status	References
Fluidized bed kiln	• FBK energy use is expected to be 10 to 15 percent lower than that of conventional rotary kilns. • NO_x emissions are reduced to 0.77 kg/tonne clinker, compared to 2.1 to 2.6 kg/tonne clinker for conventional kilns, because of lower combustion temperatures in the FBK (Worrell and Galitsky 2004). • Future FBK fuel consumption is estimated at 2.66 to 3.1 GJ/tonne clinker. This might be less than that of conventional rotary kilns but not of modern precalciner rotary kilns, which have demonstrated fuel use of 2.7 to 2.8 GJ/tonne clinker (Worrell and Galitsky 2004). CSI/ECRA (2009) papers that the FBK reduces thermal energy use by up to 300 megajoules (MJ)/tonne clinker but increases the electricity used by approximately 9 kWh/tonne clinker (CSI/ECRA 2009). • An FBK needs less space and has greater flexibility with respect to raw material feed than conventional rotary kilns do (Worrell and Galitsky 2004).	Demonstration stage	Worrell and Galitsky (2004); NEDO (2008); CSI/ECRA (2009)

Table 3. Emerging alternative raw material technologies for cement production

Technology Name	Energy/Environment/Other Benefits/Costs	Commercial Status	References
Use of steel slag as kiln raw material - CemStar® Technology	• CemStar® technology increases clinker production by up to 15 percent compared to the conventional process. • CemStar® technology allows replacement of 10 to 15 percent of clinker by electric arc furnace slag. • Using 10 percent slag would reduce energy consumption by 0.19 GJ/tonne, CO_2 emissions by roughly 11 percent, and NO_x emissions by 9 to 60 percent, depending on kiln type and plant specific conditions (Worrell et al. 2008; Perkins 2000). • Equipment costs are mainly for handling materials and vary from $200,000 to $500,000 per installation. Total investments are approximately double the equipment costs. CemStar® charges a royalty fee. • Cost savings result from increased income from additional clinker produced without increased operation and energy costs. • Cost savings also come from reduced iron ore purchases because the slag helps to meet iron needs in the clinker. • In 1999, the U.S. Environmental Protection Agency (U.S. EPA) awarded special recognition to the CemStar® process in the U.S. as part of the ClimateWise program (Worrell et al. 2008).	Semi-commercial	Worrell et al. (2008); Perkins (2000)
Non-carbonated raw material for cement production – use of carbide slag	• The type and quality of the clinker produced by CCR are unchanged compared to clinker produced by traditional methods. • Using CCR will avoid significant CO_2 emissions. In a cement plant in Sichuan Province, China, CCR was used to produce 600,000 tons of clinker per year. The resulting annual CO_2 emissions reduction was papered to be equal to 224,540 tCO_2. • When CCR is used instead of limestone, fuel consumption can be reduced because some chemical reactions that would take place if limestone was used will not take place if CCR is used. • The capital cost to implement this technology in two NSP kiln cement plants in China is papered to be between US$2.9 and US$4.3 Million (1 US$= 6.83 Chinese yuan). • Use of CCR in the cement industry mitigates the risk of pollution to environments, especially water resources and surrounding landfills (UNFCCC 2008a, 2009).	Semi-Commercial	UNFCCC (2008a, 2008b, 2009)

The CemStar® process eliminates the need to grind the slag because it allows the addition of 2-centimeter (cm) slag lumps directly to the kiln (using large lumps has traditionally led to poor clinker formation). Depending on the location of the slag injection the CemStar® process might also save heating energy (calcination energy is estimated to be 1.9 GJ/tonne clinker). Because there is already calcined lime in the slag, the CemStar® process results in reduced CO_2 emissions from calcination. The lower combustion energy conditions and flame temperatures also lead to a decrease in NO_x emissions (Worrell et al. 2008).

2.3.2. Non-carbonated Raw Material for Cement Production – Use of Carbide Slag

Carbide slag, also known as calcium carbide residue (CCR), is an unavoidable solid-waste byproduct of the industrial production of ethyne, polyvinyl chloride, polythene alcohol, and other products. A large amount of carbide slag from industrial production causes serious pollution in the surrounding environment, especially in water. Because there are no other appropriate disposal methods, carbide slag is currently disposed of in landfills.

In conventional cement production, limestone is decarbonated in the pyroprocessing stage (main reaction: $CaCO_3 \rightarrow CaO + CO_2$) to produce CaO (the main content of clinker) and CO_2; this accounts

for more than half of the CO_2 emissions during clinker production. To decrease the CO_2 emissions, CCR can be used to partially replace limestone as a raw material. Calcium hydroxide [$Ca(OH)_2$], the main content of CCR, produces CaO and water (H_2O) during pyroprocessing (e.g., in a cement kiln) without CO_2 emissions (main reaction: $Ca(OH)_2 \rightarrow CaO + H_2O$). Thus, using CCR will substantially reduce CO_2 emissions from cement production (UNFCCC 2008a). Using CCR in cement kilns entails the following steps: 1) CCR dehydration and transportation, 2) Grinding and storage, 3) Raw material homogenization, 4) Clinker burning, 5) De-dusting (UNFCCC 2009)

2.4. Emerging Alternative Cement Products

Table 4 shows the energy, environmental and other benefits as well as commercialization status of emerging alternative cement products. The description of each technology is given below.

2.4.1. Cement/Concrete Based on Fly Ash and Recycled Materials

Fly ash is a byproduct of coal burning that can have cementitious characteristics similar to those of Portland cement. The binding properties of fly ash depend on the type of coal burned and nature of the combustion process that produces the ash. Fly ash usually replaces no more than 25 percent of the Portland cement in concrete. Better understanding of the binding capacities of different types of fly ash might reveal additional possibilities. If the use of fly ash in concrete could be increased, the greenhouse gas footprint of concrete could be reduced. Increasing the amount of fly ash used in concrete would put to practical use large amounts of unused fly ash (39 million tons of fly ash is unused each year in the U.S. according to data from 2004). Ongoing research is focused on developing high-volume-fly-ash concretes. However, these products still use a significant amount of Portland cement.

In 2008, Montana State University/Western Transportation Institute performed research using 100-percent fly ash concrete with glass aggregate. This fly-ash-and-glass concrete was used successfully to construct both structural and nonstructural elements of a building. However, further research is required on this new material's fundamental engineering properties (Cross et al. 2005). The study identified 96 plants throughout the U.S. as potential sources of ash that could be used as the sole binder for concrete (Roskos et al. 2011).

Several existing companies produce cement or precast concrete and other building materials from recycled industrial wastes. One company is RecoCement, which has developed a technology to produce cement made entirely from recycled materials, primarily fly ash. (RecoCement 2011). CERATECH is another company that produces cement from fly ash (CERATECH 2012). CalStar Products, Inc. also has an innovative technology that uses recycled fly ash as a primary component in architectural facing bricks and durable pavers (CalStar Products 2012).

2.4.3. Geopolymer Cement

Geopolymer materials fit in the category of current innovative technology for the construction industry. In contrast to Portland cement, geopolymers rely on minimally processed natural materials or industrial byproducts as binding agents. Potential energy and CO_2 savings from the use of geopolymers are significant. Geopolymer cements that are used as binders are composed of a reactive solid component and an alkaline activator. Reaction with the alkaline agent causes a three-dimensional, inorganic, alumosilicate polymer network to form, which contributes to the high compressive strength of the hardened product. Materials suitable for a geopolymeric polycondensation[1] are alumosilicates, which can be found in nature (metakaolin, natural pozzolana) or industrial wastes (fly ash, GBFS) (CSI/ECRA 2009). Geopolymers are manufactured at relatively low temperatures, with calcining of aluminosilicates occurring at 750°C. However, no energy consumption data are available for this process (APP 2009).

Until now, geopolymers have been produced only for demonstration purposes and used only for non-structural applications such as paving (CSI/ECRA 2009). Other probable applications of geopolymers are bridges, and structural retrofits using geopolymer-fiber composites. Geopolymer technology is most advanced in precast applications, which can relatively easily handle sensitive materials such as high-alkali activating solutions and because of the controlled high-temperature curing environment that many geopolymer systems require (U.S. DOT 2010).

Pyrament®, a North-American geopolymer application with blended Portland-geopolymer cements, is used successfully for rapid pavement repair (U.S. DOT 2010). Blue World Crete Company produces a geopolymer that combines a proprietary binding agent with materials containing alumina silicate (Blue World Crete 2012).

[1] Any condensation reaction, of a monomer having two functional groups, which leads to the formation of a polymer.

Table 4. Emerging alternative cement products

Technology Name	Energy/Environment/Other Benefits/Costs	Commercial Status	References
Cement primarily of fly ash and recycled materials	• Recycling fly ash to produce concrete avoids the need for landfill disposal of this industrial byproduct. • Use of fly ash reduces or eliminates the need to mine virgin raw materials for Portland cement production and provides a constructive use for waste fly ash. • Increasing use of fly ash will significantly reduce the energy use needed for cement and concrete production. • Increasing use of fly ash can significantly reduce the greenhouse gas footprint of concrete production by eliminating CO_2 emissions from energy use and calcination in cement production. • Using recycled materials as aggregate in concrete diverts these materials from landfills and reduces the need for mined aggregate. Pulverized post-consumer glass is a recycled material that can be used as concrete aggregate.	Semi-commercial	Roskos et al. (2011); Cross et al. (2005); RecoCement (2011); CERATECH (2012)
Geopolymer cement	• Potential energy and CO_2 savings from the use of geopolymers are significant. • Expected CO_2 emissions for geopolymers are about 300 kg CO_2/tonne product. This estimate does not take into account emissions from production of the activators, such as sodium silicate, for which no data are available (CSI/ECRA 2009). • Major geopolymer systems rely on minimally processed natural materials or industrial byproducts as binding agents. • The use of industrial byproducts/wastes in the production of geopolymers creates a constructive use for these materials.	Demonstration stage[1]	Geopolymer Institute (2012); CSI/ECRA (2009); Blue World Crete (2012)

2.5. Emerging Carbon Capture Technologies for the Cement Industry

Table 5 shows the energy, environmental and other benefits as well as commercialization status of emerging carbon capture technologies for the cement industry. The description of each technology is given below.

2.5.1. Oxygen Enrichment and Oxy-fuel Technologies

The U.S. cement industry has used oxygen-enriched combustion since the 1960s. Using oxygen-enriched combustion air increases energy efficiency, production capacity, and allows fuels with low calorific value to be used in place of fossil fuels. This increases kiln flame temperatures while reducing CO_2 emissions. Short-term experiments have demonstrated a kiln capacity increase of 25 to 50 percent when combustion air is enriched with 30 to 35 percent oxygen (by volume). Oxygen enrichment has not yet been applied for purposes of reducing CO_2 emissions. Enriched combustion air might reduce kiln fuel use and thus CO_2 emissions, but additional power is required to produce oxygen, so it is not clear whether there would be a net reduction in total energy use.

Oxy-fuel technology is another emerging candidate for CO_2 capture in new cement kilns. This technology is currently still being researched (ECRA 2007 and 2009). Oxy-fuel technology differs from oxygen enrichment in that oxygen enrichment does not replace air but injects oxygen into the combustion zone along with combustion air.

In contrast, oxy-fuel technology replaces the air with an oxygen stream, using pure oxygen instead of air for fuel burning. Because this eliminates the nitrogen that would normally be in the air that is traditionally used for fuel burning, fuel requirements and flue gas volumes are reduced. When the oxygen stream is fed to the kiln, the resulting kiln exhaust gas contains up to 80 percent of the CO_2 concentration from the fuel burning. This fraction of the exhaust stream is transported to a CO_2 separation, purification, and compression facility (U.S. EPA 2010).

Technical issues associated with use of oxy-combustion (oxy-fuel technology) at a cement plant include: the high flame temperatures (3,500°C) produced by this process which is too hot for proper operation of a cement kiln and the need for recycling a portion of the flue gases back to the combustion zone to provide the necessary dilution; heat-transfer characteristics that are influenced by changing the atmosphere within the combustion chamber; deterioration of kiln walls at higher oxygen levels; clinkering process chemistry under different atmospheres need further investigation; costly removal of contamination from the CO_2-rich exhaust gas resulting from excessive air infiltration; power consumption increases of 200 to 240 kWh/tonne O_2 for oxygen delivery using an air separation unit (see table 5) (Barker et al. 2009).

Table 5. Emerging carbon capture technologies for the cement industry

Technology Name	Energy/Environment/Other Benefits/Costs	Commercial Status	References
Oxygen Enrichment and Oxy-fuel Technologies	• Oxygen enrichment technology reduces fuel use by 100 to 200 MJ/tonne clinker but increases electricity use by 10 to 35 kWh/tonne clinker compared to fuel and electricity use in conventional processes (CSI/ECRA 2009). • Short-term experiments have papered a 25- to 50-percent increase in kiln capacity with oxygen enrichment at 30 to 35 percent (volume) in combustion air (CSI/ECRA 2009). • With oxy-fuel technology, overall energy requirements drop by 75 to 84MJ/tonne cement despite an increase of 92 to 96 kWh/tonne cement that is attributable primarily to operation of the CO_2 separation, purification, and compression facility as well as the oxygen production (U.S. EPA 2010). • With oxy-fuel technology, reduction in CO_2 emissions from reduced fuel combustion ranges from 454 to 726 kg CO_2/tonne cement; however, this would be partially offset by CO_2 emissions increasing by between 50 and 68 kg CO_2/tonne cement because of increased electricity use (U.S. EPA 2010). • Using oxy-fuel technology only in the precalciner avoids approximately 61 percent of CO_2 emissions from the process. Using the technology in both precalciner and kiln could avoid almost 100 percent of CO_2 emissions although greater technical uncertainties are associated with this approach (Barker et al. 2009). • The additional investment costs for oxy-fuel technology in a new facility are estimated to range from $495 to $540 million, and operational costs would increase by $10 to 13/tonne cement for a facility producing 2.2 million ton /yr. Costs related to transport and storage of CO_2 are not included (U.S. EPA 2010).	Oxy-fuel technology: Pilot stage Oxygen enrichment: Commercial	ECRA (2007 and 2009); U.S. EPA (2010); Barker et al. (2009); CSI/ECRA (2009)
Post-combustion carbon capture using absorption technologies	• When post-combustion absorption technologies are used, thermal energy consumption increases by 1,000 to 3,500 MJ/tonne clinker, and electricity consumption increases by 50 to 90 kWh/tonne clinker. Overall, primary energy consumption will be high, likely more than 3 MJ per kg CO_2 avoided. • Direct CO_2 reduction potential from a carbon-capture system is up to 750 CO_2/tonne clinker. Indirect CO_2 emissions increase by 25 to 60 kg CO_2/tonne clinker because of increased electricity consumption. • A rough prediction is that an investment of $130 to $443 million will be needed for this technology, and operations will cost $13 to 96/tonne cement, excluding the cost of CO_2 transport and storage (CSI/ECRA 2009; EPA 2010).	Pilot stage	CSI/ECRA (2009); ECRA (2009); U.S. EPA (2010); Barker et al. (2009); Bosoaga et al. (2009)
Calera process	• Using less cement and more supplementary cementitious material from the Calera process could reduce CO_2 emissions from concrete production. Calera claims that its process requires less additional energy than many other carbon capture and storage processes if off-peak and low-carbon energy sources are utilized for manufacturing the required alkalinity. • Calera technology focuses not only on capturing CO_2 that would otherwise be released into the atmosphere but also on recycling this CO_2 for concrete production. This is an advantage compared to some other CCS technologies (e.g., post-combustion absorption) in which CO_2 would be stored underground, a technique whose safety is still in question. • In addition to capturing CO_2, the Calera technology can capture SO_2 and other acid gases, mercury, and other heavy metals (e.g., silver, arsenic, barium, cadmium, chromium, lead, and selenium) and can safely isolate them in calcium carbonate precipitate (Bren 2011).	Pilot stage	Calera (2012); Bren (2011)
Carbonate looping technology	• In addition to the benefit of the CO_2 captured by the calcium looping system, use of the spent precalcined CaO as the raw material for cement production would reduce cement plant CO_2 emissions by more than 50 percent. • Reusing spent sorbent reduces the waste stream. • Using spent sorbent instead of limestone for the cement production conserves natural limestone resources.	Development stage	Dean et al. (2011); Pathi et al. (2011); Hollingshead and Venta (2009)
Industrial recycling of CO_2 from cement process into high-energy algal biomass	• On average, about 1.8 tons of CO_2 will be utilized per ton of dry algal biomass produced. • This technology has significant potential for large-scale reuse of CO_2. • Existing crude oil refineries can use algal oil. • Local use of CO_2 emissions avoids the need for transportation and storage. • Algae cultivation systems can avoid competing with terrestrial food crops, a challenge that has restricted development of first-generation biofuels. • Sewage wastewater can be utilized as a source of nutrients for this technology. • The yield of an algae cultivation system is forecast to be 10 times greater per land area than the yields of terrestrial vegetable oil crops. • This technology could offer a carbon negative pathway in which carbonization is used to produce fuel (Parsons Brinckerhoff and GCCSI 2011).	Demonstration stage	Parsons Brinckerhoff and GCCSI (2011); APP (2008); Pond Biofuels (2012)

2.5.2. Post-combustion Carbon Capture Using Absorption Technologies

Solvent scrubbing has been used to separate CO_2 in chemical industry exhaust streams (Bosoago et al. 2009). Post-combustion carbon capture takes advantage of this commercially mature technology and applies a common solvent, monoethanolamine (MEA), for CO_2 scrubbing. Because of the high cost of this solvent, it has to be regenerated and reused, an energy-consuming process that results in additional CO_2 emissions. SO_2, NO_2, and oxygen play an important role in solvent degradation mechanisms. Therefore, the SO_2, NOx, and particulate matter concentrations in flue gases need to be reduced to a minimum before the flue gases go through the solvent scrubbing CO_2 capture system (CSI/ECRA 2009).

Barker et al. (2009) evaluated several technical issues associated with post-combustion amine scrubbing using MEA in a new cement plant. An extensive study by the International Energy Agency (IEA) proposes that cement plants make major changes to implement absorbent technologies. These changes include: addition of a solvent scrubber and regenerator as well as a compressor to increase the pressure of CO_2 emissions for transport by pipeline, high-efficiency flue gas desulphurization and de-NO_x to meet flue gas purity requirements, and a combined heat and power plant to provide steam for regeneration of the solvent. IEA performed a techno-economic analysis of these changes for a new dry-feed-process cement plant located in the UK, with a five-stage preheater and production capacity of 1.1 million tons of cement/yr. The analysis showed that total fuel consumption (coal) increased by 207.2 MW, and net power consumption from the grid decreased by 13.1 MW (because of onsite electricity generation) compared to fuel and power consumption of a similar cement process without the CO_2 capture system. This takes into account excess electricity generation of 2.9 MW by the combined heat and power plant. Avoided CO_2 emissions were 594,000 tons/yr, or 653,200 tons/yr, taking into account the import and export of electricity, which showed 74-percent and 77-percent reductions, respectively. Capital costs increased by $443M, and operating costs, taking into account the export of excess electricity generation for the steam plant, increased $95.7 M/yr (U.S. EPA 2010).

Absorption technologies are currently only being used at a pilot scale in the energy sector. Demonstration plants are in the planning phase (ECRA 2009), with the first industrial application expected around 2020. With modifications, these technologies should then be available for the cement industry (CSI/ECRA 2009). Availability of a transport (pipeline) grid and storage sites are also important factors necessary to support this CO_2-capture technology (see table 5).

2.5.3. Calera Process

The Calera process captures power-plant CO_2 and stores it as a carbonaceous material. Using a process known as “mineralization via aqueous precipitation,” the Calera process converts gas into stable solids such as metastable calcium, magnesium carbonate, and bicarbonate minerals. The process requires a high pH and thus is most economic when power plants are located near sources of suitable brines, which are extracted from geologic formations, as well as alternative sources of alkalinity and minerals. Calera cement is similar to Portland cement and aggregate but can differ by site based on the inclusion of trace components. After processing, the solid materials produced by the Calera process can be used in various construction applications. Calera has another proprietary high-efficiency electrochemical process called “alkalinity based on low energy” uses only salt and electricity to produce NaOH and HCl ($NaCl + H_2O \rightarrow NaOH + HCl$) (Calera 2012).

Co-producing electricity with the Calera carbon capture process could reduce power plant emissions by up to 90 percent, with offsetting CO_2 emissions of 10 to 30 percent from the Calera process (CO_2 emissions associated with the energy use by Calera process). It is possible that Calera supplementary cementitious material could replace 20 percent of ordinary Portland cement in concrete, significantly decreasing concrete’s carbon footprint. Challenges associated with the Calera process include dependence on brines extracted from geologic deposits; the need for alternative natural alkalinity resources and/or minerals near the power plant; increase in energy use by Calera process (energy penalty); production of more calcareous material than needed in the current market; potential impact on water balances and hydrology from extraction and reinjection of brines; and the need for environmentally acceptable management of the brines and bicarbonate solutions that must be pumped from and returned to geologic formations as part of the process (Bren 2011).

Calera has a demonstration project at Moss Landing, California that is capable of capturing 30,000 tons per year of CO_2, which is equivalent to a 10-MW electric (MWe) natural gas power plant (Calera 2012). Other Calera demonstrations are planned in California and Wyoming in the USA as well as in China and Australia during the next few years.

2.5.4. Carbonate Looping Technology

Amine scrubbing carbon capture technology uses a significant amount of additional energy that

can be reduced by using lime (CaO) as a regenerable sorbent. After reacting with CO_2 for a number of cycles, CaO loses its ability to react with CO_2 and usually becomes waste. However, the exhausted (spent) sorbent could partially replace the main raw material in cement manufacturing, $CaCO_3$. Because the spent sorbent would not need to be calcined in the kiln (releasing CO_2 to form CaO), using it as a replacement for limestone in cement would reduce CO_2 emissions from calcination, which accounts for more than 50 percent of total CO_2 emissions from the cement production process. This process is also known as a "looping cycle" or "carbonate looping" technology (Dean et al. 2011).

Abanades (2008) describes the fundamentals of the carbonate looping process, and Pathi et al. (2011) created a model of a simple carbonate looping process based on the average conversion of calcined limestone. The model is used to study the influence of average conversions of limestone in the carbonator on the flow rates of various streams within the looping process, and to study the energy necessary for calciner reactivation. In addition, the model is used to study the carbonate looping process as implemented in the cement pyroprocess.

The European *Cement* Research Academy (*ECRA*) has estimated that modern anthracite- and lignite-fired power plants emit 750 or 950 grams(g) CO_2 /kWh, respectively. An 800-MWe power generation plant discharges approximately 620 or 780 tpd of degraded CaO sorbent (the sorbet has a lifetime of 30 cycles). For a mid-sized plant producing 3,000 tpd of clinker, use of precalcined CaO could meet approximately one-third of the raw material needs. This looping technology would be feasible if the cement plant and the power plant both function in close cooperation, ideally, next to each other in an operational link (see table 5) (Hollingshead and Venta 2009).

2.5.5. Industrial Recycling of Cement Process CO_2 Emissions into High-energy Algal Biomass

Concentrated CO_2 streams produced by cement or power plants could be used to cultivate algae. Due to algae's sensitivity to impurities, the recycled CO_2 would have to undergo a cleaning process before being used for this purpose. Currently, closed algal cultivation systems for biofuel production have moved from the research phase to pilot and demonstration projects. Because of algae's potential as a feedstock for biodiesel production, food products, and chemicals, several large global companies, including BP, Chevron, Virgin, and Royal Dutch Shell, have invested research funding in this area (APP 2008).

Commercial-scale systems range from 10 to 100 hectares and are estimated to absorb between 500 and 55,000 tonne CO_2 per system per year. Algae biomass fuels are predicted to become the largest biofuel class by 2022 when they will account for an estimated 37 percent of all biofuels produced. However, large land areas are required for algae cultivation, so the potential for this technology could be limited in areas with high land prices (Parsons Brinckerhoff and GCCSI 2011). Similar to existing agricultural systems, algal cultivation requires large quantities of nutrients, which makes it CO_2 intensive. The technical and reliability barriers to this technology are expected to be overcome within 3 to 5 years, and commercial deployment is expected in 5 to 10 years (APP 2008).

Pond Biofuels, a Canadian company, captures CO_2 and other emissions from a cement plant to create nutrient-rich algae slime. The algae are grown at a facility next to the cement plant to be harvested, dried, and then used as fuel in the plant (Pond Biofuels 2012). Algenol is a U.S. company planning to develop a $850-million algae plant in the Sonora Desert. Approximately 6 million tons of CO_2 per year would be reused to produce 3.8 million cubic meters of ethanol. Solazyme is another company taking advantage of the microbial fermentation process, fermenting algae on a large scale without the need for sunlight, to produce algae oil. A third company, MBD Energy, uses algae to recycle captured industrial flue-gas emissions and produce algae oils suitable for manufacture of high-grade plastics, transport fuel, and livestock feed (see table 5) (APP 2008).

3. CONCLUSIONS

This paper describes eleven emerging energy-efficiency and CO_2 emissions reduction technologies for cement and concrete production. The information presented for each technology was collected from various sources, including manufacturers. As can be seen from the information presented in this paper, most of the technologies have an energy penalty associated with their operation. Therefore, further research is needed to improve and optimized these technologies in order to minimize their energy penalty. In addition, for some technologies, there was not much information available except from the technology developer. Conducting independent studies and validation on the fundamentals, development, and operation of these emerging technologies can be helpful to private and public sectors as well as academia.

Shifting away from conventional processes and products will require a number of developments including: education of producers and consumers; new standards; aggressive research and development to address the issues and barriers confronting emerging technologies; government

support and funding for development and deployment of emerging technologies; rules to address the intellectual property issues related to dissemination of new technologies; and financial incentives (e.g., through carbon trading mechanisms) to make emerging low-carbon technologies, which might have a higher initial costs, competitive with the conventional processes and products.

The purpose of this paper is solely informational. Neither the authors nor Lawrence Berkeley National Laboratory endorses or certifies any of the companies or technologies mentioned, nor do we take responsibility for any actions that readers might take in regard to these technologies.

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Case Study of Optimal Byproduct Gas Distribution in Integrated Steel Mill Using Multi-Period Optimization

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ABSTRACT

Energy constitutes about 20 % of the total production cost in an integrated steel mill, and therefore energy efficiency is crucial for profitability within the environmental policy context.

An integrated steel mill generates high calorific value byproduct gases at varying rates. The differences between gas generation and consumption rates are compensated with gas holders. However, under certain circumstances the imbalances can lead to the flaring of excessive gas or require the purchase of supplementary fuel.

This presentation describes a steel mill energy management system with sophisticated monitoring, planning, and optimization tools. It models the complex energy interconnections between various processes of the mill and determines the optimal trade-off between gas holder level control, flare minimization, and optimization of electricity purchase versus internal power generation. The system reduces energy cost, improves energy efficiency, manages carbon footprint, and provides environmental reporting features.

INTRODUCTION

The principal energy flows between the various production sections in an integrated steel mill are outlined in the energy map in Figure 1.

Byproduct gases are generated in the primary reduction process in Blast Furnaces or Corex Furnaces, in coke ovens and in the steelmaking process in Basic Oxygen Furnaces. Gas holders are available for gas storage to compensate for the temporary imbalances between consumption and production rates. Surplus gas that cannot be used in the processes or in the power plant is flared and additional Natural Gas can be imported from the grid in case of shortage.

The power plant has steam boilers that can be fired with various combinations of fuels, including byproduct gases, imported natural gas, and byproduct or purchased liquid fuels. The steam produced in the boilers is used to generate electricity in the power plant and supplied to various consumers in the production sections, building heating, etc.

Most production sections will be consumers of the byproduct gases. Different users require different calorific values (compositions) resulting in use of gas from specific streams or from gas mixing stations.

All production sections consume electricity. Electric power is imported from the grid and generated in the mill power plant steam turbine generators or by blast furnace reduction turbine(s). Electric power may potentially be also exported.

As appears from the above, the different forms of energy consumed and generated at the plant are interconnected and interactive and should therefore be optimized together. The optimization calculates optimal byproduct gas distribution schedules to the consumers in the production sections and to the boilers in the power plant. The optimization will maintain the levels of the gas holders within the allowed ranges and minimize gas flaring. At the same time it will also calculate the

optimal own power generation and purchased power schedules.

The efficient use of the byproduct gases is essentially important for the profitability of steel mill operation because of the high energy volumes and costs involved. The improved efficiency will also reduce carbon emissions, which are traditionally large in the steel industry. Despite the importance and the potential benefits, the reported optimization applications tend to be more like academic feasibility studies while descriptions of actual robust real time multi-period optimization systems of steel mill byproduct gases are still missing (1), (2).

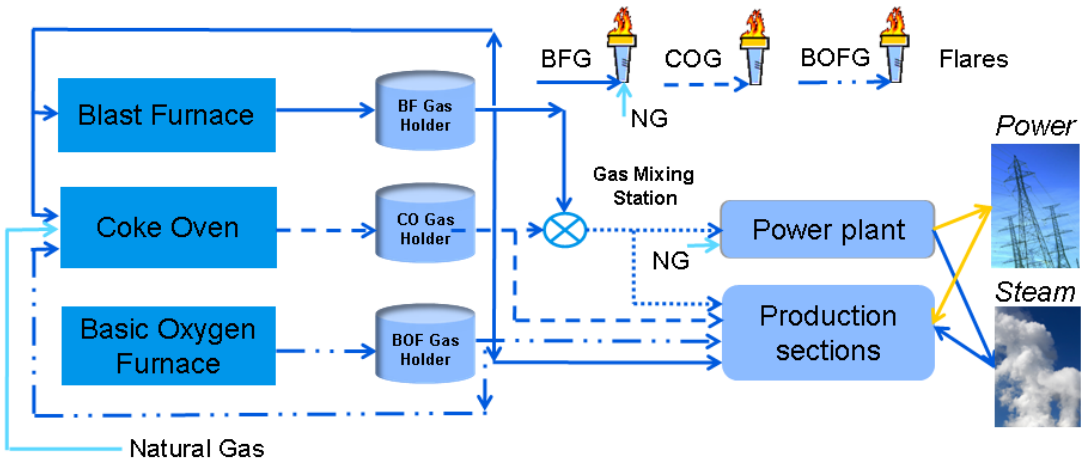

Figure 1. Integrated steel mill energy flows

FEASIBILITY STUDY

ABB has carried out a feasibility study for an integrated steel mill that produces multiple types of high calorific value gases that have to be distributed between multiple consumers. In this case, the gas network consists of five different types of gases with different calorific values as follows:

- Blast Furnace Gas (BFG)
- Coke Oven Gas (COG)
- Basic Oxygen Furnace Gas (BOFG)
- High Pressure Corex Gas (HPCX)
- Low pressure Corex Gas (LPCX)

In addition, there are two Gas Mixing Stations that produce mixed gas using BFG and COG.

Byproduct gases are supplied to 40 consumers, which include in-house as well as external consumers.

Currently, the gases are distributed to various consumers based on heuristic rules derived from operator experience. The procedures may not allow timely handling of uncertainties in the gas generation and demand of various consumers in an optimal manner. This increases the flaring of byproduct gases resulting in loss of energy and money.

The problem is to optimally distribute the above gases among the consumers to meet the demands of all the consumers while minimizing the flaring of gases. While achieving these objectives, the optimal distribution has to respect various types of restrictions related to the gas network configuration due to compressors, gas mixing stations, and the gas combinations that can be supplied to the consumers. In addition, the flow rate limitations in the gas networks and gas holder level rise rate limitations shall be respected.

The gas network configuration restrictions lead to integer type decision variables to select between the possible alternative configurations. In the study the optimization problem was configured as a Mixed Integer Linear Programming (MILP) model which was solved using a commercial solver. The model was tested with data recorded from the steel plant. In order to make the tests more

realistic, ± 10% to 15% variations were considered in demand and supply of the gases, respectively. The tested variations simulated disturbance scenarios, which can frequently occur in a steel plant.

For all of the tested cases, the flaring of gases was less than 50% of the current practice at the steel plant. Thus, the proposed optimization solution reduced significant amount of flaring, and Increased energy efficiency. This will finally lead to significant amount of profit, i.e. about 2 - 5 MUSD/year for a steel plant with 8 million tons/year steel production.

ENERGY MANAGEMENT WITH GAS OPTIMIZATION

ABB is currently implementing an Energy Management System (EMS) project that includes real time energy optimization for gas, electrical and steam networks and power plant of an integrated steel mill. The project is being carried out as a joint effort together with the project teams of ABB and the steel mill, and it is now in the commissioning phase.

Process Description

The mill has the capacity to produce up to 5 Million tons of steel per year. The main production sections considered include the sintering plant, coke oven plant, two blast furnaces, steel plant with basic oxygen converters and in ladle vacuum degassing, continuous casters, hot strip mill and multiple finishing lines.

The gas fuels include byproduct gases (COG, BFG and BOFG, also called LDG) and imported Natural Gas (NG). Liquid fuels used at the Power Plant include byproduct tar and naphthalene and imported oil.

The Power Plant produces steam in four steam boilers. The boilers can be fired with the available gas and liquid fuels in various combinations. Boiler efficiencies are different depending on the boiler unit and the fuel used. For some boilers and fuels the efficiency is relatively constant in the allowed operating range, but for others the efficiency depends on the operating point.

The high pressure steam is used to generate electricity in four turbine-generators and to run two turbo-blowers that deliver air to the blast furnaces. Medium or low pressure steam is used for vacuum degassing in the steel plant, heating of buildings, etc.

In addition to the power generated in-house, purchased electricity is supplied from the grid as needed to meet the total mill demand. The time schedule of electricity volumes to be purchased from the day-ahead market shall be forecasted daily for the next day.

Production rates of byproduct gases as well as gas, electrical and steam energy demands of the production sections are based on the mill's production schedule and there is little or no flexibility to change them.

Optimization Model and Goals

The optimization model maximizes the efficiency of using the byproduct gases in the production sections and power plant. To support daily planning and monitoring of operation, the time horizon of the model is up to one week with ½h time steps.

The optimal solution minimizes the total cost under the following conditions:

- Gas holder levels shall be maintained within allowed operating ranges to avoid flaring of gases
- The power plant shall be operated in the most efficient configuration possible within appropriate constraints, i.e.
    - Allocation of gas and liquid fuels to the boilers shall consider boiler efficiencies on each fuel. For some boiler/fuels, the efficiency changes with operating point
    - Boiler startup ramp rates and costs shall be considered
    - The constraints on connecting boilers and turbines into the HP steam networks shall be respected
    - The required operating margins (spinning reserves) of the generation units shall be respected
- The volumes of purchased electricity and own power generation are optimized. The price of purchased electricity may include penalty costs due to forecast errors.

- The model can also be extended to optimize the volumes of sold electricity and byproduct gas, if the technical and contractual opportunities are available to export them.

The total energy cost to be minimized consists of the cost of purchased fuels (NG, oil) and electricity. The optimal solution will also minimize the flaring of gases and maximize the efficiency of steam and power generation and use.

EMS Implementation

The forecasted energy consumption and byproduct gas generation schedules are based on previously recorded correlations between mill production rates and the variables to be forecasted. Medium term production planning data needed for the calculation of the forecasts is entered into the EMS from an interface to the mill's order processing and production planning system. This data may be updated later by production schedules received from short term production planning and tracking systems. Forecasted production rates and interruptions can also be entered and modified by production section operators from EMS user interface.

The optimization model is configured using ABB's Economic Flow Network (EFN) modeling tool. Energy consumers, suppliers, boilers, turbines, gas holders, etc. components and networks with related contracts, prices, costs and constraints can be configured into the model from EMS user interface and maintained without programming. The EFN modeling tool transforms the configured model into an optimization problem that is then solved by a 3rd party MILP Solver.

The input variables to the model include

- current state of production sections and power plant as measured by the instrumentation and control systems
- forecasted schedules of (gas, electrical and steam) energy demand and gas and liquid fuel generation in the production sections

The solution of the problem provides the optimal energy supply schedules for the production sections and the power plant, including schedules of

- supply of fuels to production sections and the boilers
- boiler states and steam generation rates
- steam turbine states and electricity generation rates
- in-house electricity and steam consumption at power plant
- electrical power purchased from the grid.
- NG purchased from the grid
- consumption of liquid fuels
- gas holder levels and flared gas volumes
- fuel tank storage levels

The forecasts are updated from time to time as new production plans are received from the production planning systems and the user interface. The execution of optimization is automatically activated to calculate the new optimal schedules after the changing of the forecasts and other input variables based on specified conditions.

User Interface

The main users of real time optimization are the operators of the production sections and the power plant. Production section operators will update each morning the section's production schedule and validate the forecasted schedules of gas, electrical and steam demand and byproduct gas generation. Each production section has a dedicated user interface display for the entry of the data in Gantt or trend chart from.

Power plant operators supervise and control the operation of the power plant. Each morning they will run the optimization after verifying that the production section forecasts have been properly entered and after updating the power plant inputs needed for the optimization.

The operators shall implement the optimal byproduct gas distribution and power plant operating schedules by controlling their processes and the power plant accordingly. The optimal schedules are presented on the EMS user interface using displays specifically configured for each production section and the

power plant. The display will show the optimal schedule as a bar chart diagram in parallel with the corresponding actual schedule that is updated in real time. This will help the operators to detect deviations from the optimal schedule.

Any unplanned changes in the schedules of the production sections or the power plant should be entered into the EMS by the operators. Because the quality of the optimization results is dependent on the accuracy of the optimization input variables, any changes to forecasts should be updated in advance as soon as possible.

Power plant operators have the means to control the optimization to use the available fuels and the power plant resources according to their preferences. For each boiler, the operator can select from a Gantt diagram a time-range and fuel. He can then control the use of the selected fuel in optimization by entering (*use / deny*) below the Gantt line as shown in Figure 2. If no *use / deny* data has been entered, the optimization will calculate the usage. In this way the operator can override the corresponding previous results of the optimization and start a new optimization run that will respect the settings given by the operator. The same technique can also be applied for other optimized variables.

The diagram in Figure 2 below presents actual historical data on the left, and future planned and optimized data on the right. The lower part of the diagram shows the boiler fuel flows as bars and the steam flow as a line.

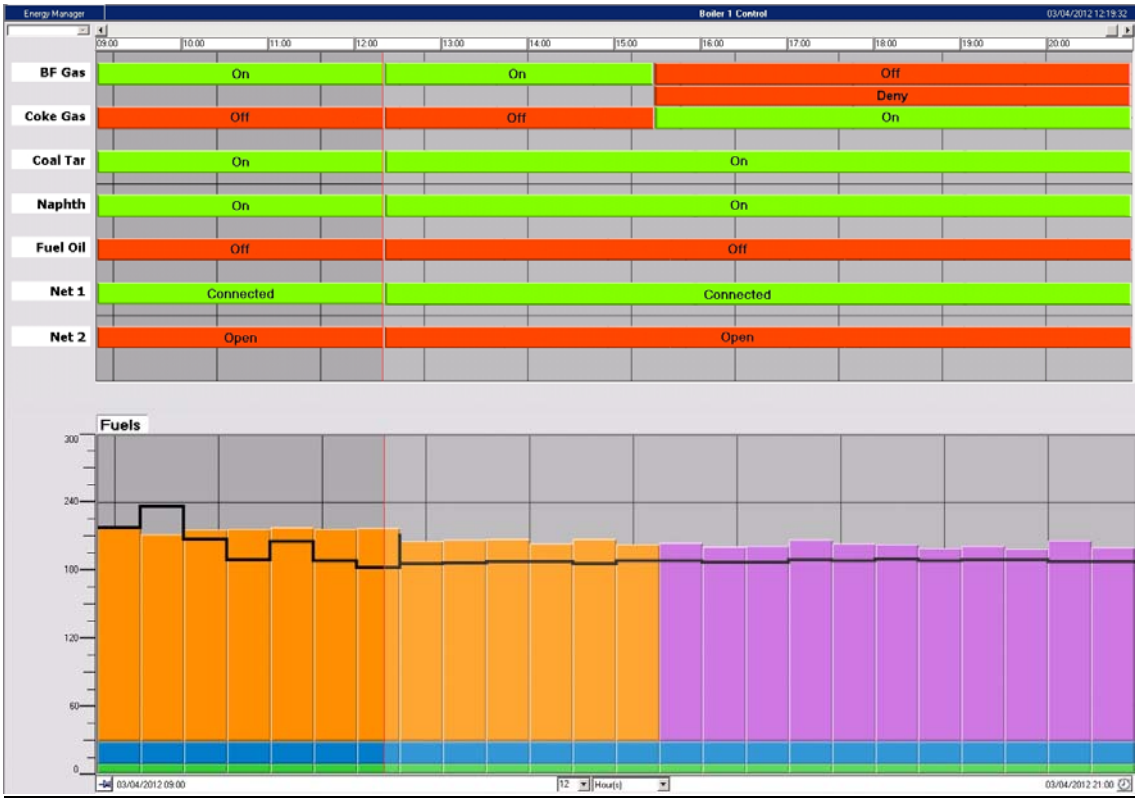

Figure 2. Boiler optimization control display

Monitoring and Targeting dashboards

The benefits of the EMS can be extended by long term Monitoring and Targeting display dashboards to visualize and analyze energy and utility consumption and other energy KPIs. A mil specific set of dashboards can be made available for the total mill and each production section in the same form.

As an example, the Energy Performance Dashboard in Figure 3 presents energy consumption, energy costs, or CO2 emissions with corresponding targets by energy type and over a time range as selected by the user. Additional dashboards are provided for the setting of targets, and analysis and reporting of the energy data.

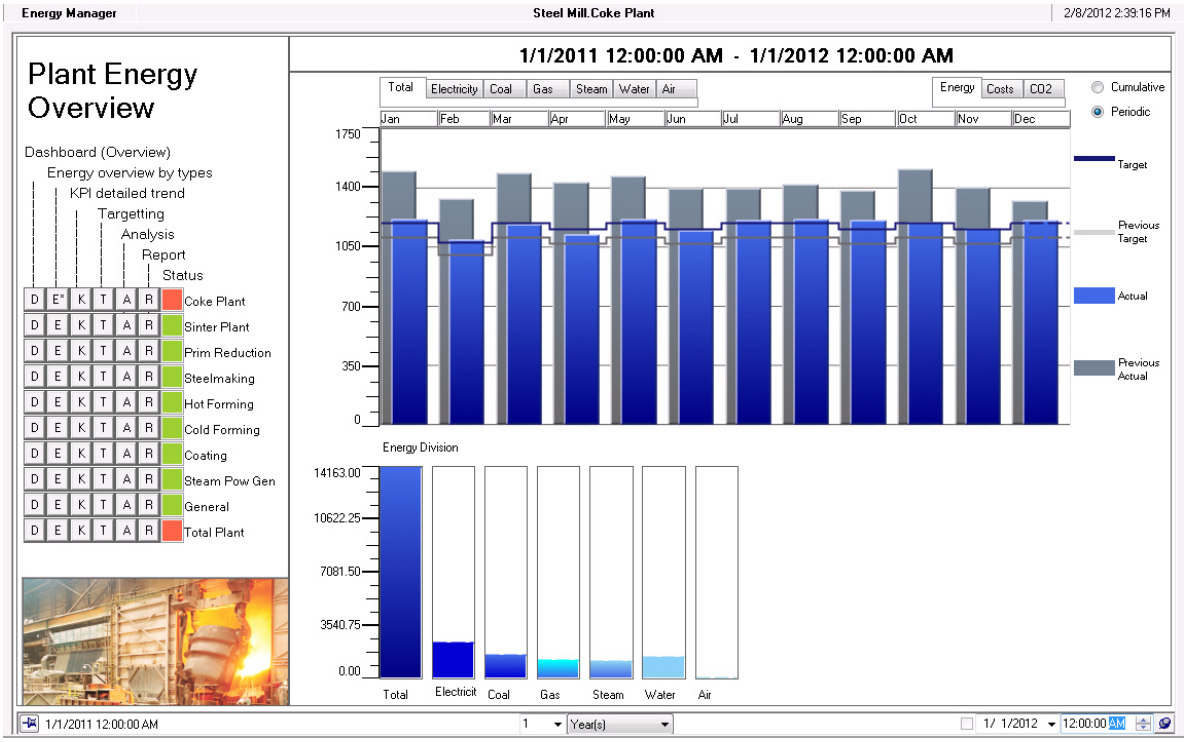

Figure 3. Energy Performance Dashboard

CONCLUSION

The implementation of the system has proceeded to the commissioning stage and as the first step the production section operators are using it to enter the electricity demand forecasts. The accuracies of the forecasts are verified by comparing with measured data.

In the early project phase the emphasis in the optimization model development was on the specification of the requirements in detail to allow model configuring. After configuring, the model is first tested using historical data recorded from the mill.

At the final step the optimization model is integrated with the demand forecasts and validated in various operating situations.

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ENERGY AUDIT EQUIPMENT

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ABSTRACT
The tools (equipment) needed to perform an energy audit include include those items which assist the auditor in measuring the energy used by equipment or lost in inefficiency. Each tool is designed for a specific measurement. They can be inexpensive simple tools or expensive technically complex or multifunctional tools. In general, tools are needed which measure light, temperature and humidity, electricity, air flow, heat loss, and general energy information.

LIGHT METER
A light meter may be used to determine the type of ballasted in a light fixture A lamp ballast is an electrical device used to limit the amount of current to the lamp. They exist as either magnetic or electronic, the electronic type being the more modern and energy efficient. An energy audit needs to determine which type of ballast is controlling the lamp.

A ballast checker is an electronic device that determines whether the ballast is magnetic or electronic. An LED light turns green if the ballast is electronic and orange if it is magnetic. It is powered by two AA batteries and is good for 15 feet from the light source.

Another type of light meter measures the lumen output of a light source. The amount of light reaching a specified location is measured to determine if the amount is sufficient for the task. The amount of light is measured in foot candles (one foot candle is equal to the light of one candle one foot from the source).

THERMOMETER
Thermometers measures the temperature of an object. Knowing the temperature is important in an energy audit because heat loss is energy loss. If it can be mitigated or eliminated, energy will be conserved. Infrared thermometer "guns" are very useful for this. They can be aimed at any object, even from a distance of 15 feet, to obtain the object's temperature.

PSYCHROMETER – measures the humidity in the air and is useful in determining comfort levels. Humidity level is also important to several industrial processes. In HVAC application analysis, changes in humidity and temperature affect the efficiency of air conditioners and chillers.

POWER METER (Volt/Amp/Watt/PF) – a combination meter to measure the voltage and amperage draw of a piece of equipment as well as calculate the wattage and power factor consumed by electrical equipment. This information is used to analyze the operating efficiency of electrically operated equipment.

VELOCITY/AIR FLOW METER – this meter measure the velocity of air through door/window gaps and other leakages, across filters, and air flow from air conditioning registers. These measurement is used to determine infiltration/exfiltration cooling and heating losses and motor and fan efficiencies. They are also used to determine if equipment is meeting efficiency standards.

ULTRASONIC METER – it is used to locate air and steam leaks and motor bearing problems. The meter measures the decibel sound level to determine the size of the leak. This is an expensive device (several thousand dollars).

INFRARED THEMOGRAPHY – infrared cameras are used to locate building and electrical heat profiles. A temperature picture is taken recording heat radiation. Roof leaks, lack of insulation, poor wiring connections, electrical power overload, and other heat differential problems can be determined. This is an expensive device (several thousand dollars) but extremely useful in an energy audit.

COMBUSTION ANALYZER – measures the oxygen in the exhaust gas of a boiler. From the oxygen value the boiler's efficiency is calculated. Most analyzers are able to detect several gases ( ) and their concentration percentage.

DIGITAL CAMERA – it used to take pictures of the typical energy using systems (lighting, AC, production equipment, etc.) as well as document problems encountered (bad insulation, air gaps, poor filters, etc).

NOTEPAD/PEN – they keep a record of your findings. Each piece of equipment is documented as to its location, power rating or energy usage, and time of operation.

Your most valuable tool is your MIND and your EDUCATION.

Understanding Steam Systems

What To Do With COLD Traps …. And Why

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Presenter: Jonathan P. Walter, C.E.M.

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STEAM SYSTEMS: WHAT TO DO WITH COLD TRAPS…. AND WHY?

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ABSTRACT

Increased emphasis on energy management has helped sites reduce system cost through the diagnosis and repair of "Leaking" or "Blowing" steam traps ("Leakage Failures"). Timely maintenance response is a significant action to lower energy use and GHG emissions generated by steam production. But, what action should be taken with Cold Traps?

In every steam trap survey to determine the steam trap population's current state of health, there are usually a significant amount of steam traps determined to be "Cold" or "Low Temp" ("Drainage Failures" or "Cold Traps"). It seems that site personnel commonly assign a lower response priority to these Drainage Failures traps, and sometimes actually implement a practice to intentionally convert Leaking traps into Cold Traps by closing the inlet stop valve to immediately stop energy leakage. Subsequently, they may label those traps as "Valved-Out" or "Out of Service," but those trap stations were originally designed as needed to drain retained condensate from the system. So, the correct designation for such a trap station is "Cold," regardless of the current intention. If the trap station does not drain condensate and is not hot, it is "Cold."

It can be astounding that many sites are not convinced of what actions or priority to take to repair Cold Traps, even while intrinsically understanding that there is something wrong with having Cold Traps that can not drain condensate from a steam system. It often is simply because sites may not be fully aware of the potential dangers of uncorrected Cold Traps or the significant safety, reliability, and energy benefits of addressing them. Although safety is always the main priority, it cannot be overstated that there are huge reliability and energy benefits to prioritized repair of Cold Traps.

Unfortunately, proactive response to repair Cold Traps in a steam system is not always achieved, often because the real benefits of such a response are not understood. Therefore, further review of "WHAT TO DO ABOUT COLD TRAPS…AND WHY?" is warranted for safe, reliable, and energy-efficient management of the condensate discharge locations (**CDL**s). Several tables are provided to help sites valuate the cost impact of Cold Traps in their steam systems by using readily available historical data.

WHY ARE STEAM TRAPS NEEDED AT ALL?

Understanding Steam Systems

Users know that steam is the most reliable, effective, and efficient method to provide large amounts of heat to many industrial process and comfort heating applications. As with any system, there are maintenance requirements to keep the system operating at peak performance. With steam, typical requirements include repair of external steam leaks and malfunctioning steam traps. While the length of a steam system pipeline is relatively fixed and sections cannot be removed, some site personnel question the specific amount of steam traps installed in their system, and may ask if certain traps are needed at all – or if those traps can be removed or decommissioned. From past experience, some sites actually remove installed traps from service rather than maintain them, with the apparent goal to reduce the number of traps that may eventually require servicing. It brings about the basic question, "Why are traps needed at all?"

Some readers might imagine a steam system without the maintenance requirement for any valves or traps. It may seem unrealistic to consider a steam system without any steam traps installed, but why not begin the analysis by wondering what would happen in a steam system with no steam traps? A basic knowledge of steam systems is needed first in order to answer that question.

- Our Steam System is Saturated….. or Superheated

Misunderstanding steam systems might be at the heart of the matter. Ever hear someone describe the plant's steam system as having "Saturated" steam (**Figure 1**)? Well, if so it might be interesting to know that such a condition is impossible to obtain in a plant steam system. Steam systems contain either "Superheated" steam or "Wet" steam; but not "Saturated" steam. There are no "Saturated" steam systems providing steam to industrial plants.

Saturated steam is a condition where a perfect amount of latent heat vaporizes all water into steam. It is a "Threshold", a singular point on a total heat scale – not a region. Superheated steam is a condition generated when sensible heat is added above the required latent heat content that provides saturated steam, and is represented on a steam chart as the steam region above the total heat content of Saturated steam. Conversely, the region of steam that is below the Saturated steam threshold line is

"Wet" steam; a condition where less than 100% of the water has been evaporated (**Figure 2**).

Boilers cannot produce Saturated steam. They produce Wet steam, which must be sent through a Superheater in order to create Superheated steam. So, within the superheater, steam must first cross the Saturated steam threshold before becoming superheated. Similarly, the Saturated steam threshold is reached again as Superheated steam loses heat and eventually becomes Wet steam. For all other typical boiler conditions in a plant, boiler steam is Wet, containing water particles that attach to the steam bubbles rising though the boiled water. Boilers can include designs to separate some of the water before it exits, but not all water is removed and some remains entrained in the utility steam supplied to the plant. Then, since non-superheated, utility steam contains entrained water, the next question might be, "How wet is Wet steam?"

The best operating boilers may still contain 3 – 5% wetness in the utility steam immediately after it exits the boiler, if the boiler itself is not "pushed" to supply more steam than its capacity rating. Assuming a best condition of 95% dry steam (5% wet) from the initial supply point, what happens to its dryness throughout its path to individual use locations, such as heat exchangers, air coils, and a multitude of other applications? One thing is certain; the steam does not become drier up to the point of becoming Saturated; and just becomes increasingly Wet as it loses heat during its travels throughout the distribution pipeline. This is evident in many plants that describe the "Wet" end of the steam line.

Because steam is vapor, it has a capability to carry much entrained water with it as it travels through the distribution system, increasing the amount of water that can dis-entrain from flowing steam due to various mechanical or thermodynamic influences throughout its path. That dis-entrained water must be removed from the system to avoid being propelled at high velocity from the pressurized moving steam that shares the pipeline with it (**Figure 3**). Which leads to the next question, how high is the typical velocity of steam?

Utility steam may flow at velocities of 8,800 feet per minute (typically 6 – 8,000 fpm or more), which is equivalent to 100 miles per hour speed as long as the pipeline cross-sectional area is not restricted. Any restrictions could cause the localized steam flow at the restriction to accelerate to well over 100 mph. Imagine a slug of retained condensate, being propelled along a steam system at speeds exceeding 100 mph (**Figure 4**). What stops the slug before it impacts into piping or equipment? It nothing is done to remove the retained condensate, high velocity steam flow propelling the liquid can cause tremendous impacts on elbows, nozzle, equipment, valve packing, and flanges (**Figure 5**). Commonly known as "water hammer", the cause may be locally based in some instances, but typically it can be the result of a systemic condition caused by retention of condensate throughout.

<u>- Our Steam System is Superheated… No Traps or Maintenance of Traps Needed</u>

This can also be a misunderstanding in some plants. The question arises, "Why worry about steam traps in a superheated steam system which by its very composition cannot have condensate present?" It can sometimes also lead plant personnel to use a lower priority to repair traps on superheated steam systems, wrongly believing that superheated systems have no condensate present. Regarding condensate presence in those systems, there are several situations to consider, the first of which is start-up.

On start-up, the pipeline must be heated slowly, which generates condensate requiring drop legs and full CDLs for its removal. Start-up is also a good time to use those same drop legs for blowdown of system debris and mud, along with the condensate.

After the start-up condensate is drained and the system reaches superheat, those same drop legs and associated CDLs become a stagnant flow heat sink that causes superheat within to be lost, generating small condensate loads. Additionally, those CDLs are important safeguards for instances where superheat is lost, or when slugs enter the system - such as from opened valves that had condensate pooled above them, or when desuperheaters go awry and insert too much water into the steam flow. One of the most prevalent failures in steam systems is damage to superheated turbines from retained condensate that site personnel felt would not be present in the system.

<u>Removing Retained Condensate?</u>

"Out of sight, out of mind" is sometimes an appropriate expression that could be applied to handling of retained condensate. Unlike steam leaks that are visible to all site members, retained condensate is never seen as long as it is contained inside the pipeline, and steam has an ability to carry significant amounts of destructive condensate throughout the system. Retained condensate is easy to forget because there are no typical visual reminders – until a catastrophic event caused by retained condensate occurs.

Fortunately, steam system engineers at Consulting Engineering firms experienced in designing safe, reliable, and cost-effective systems

use best practice standards to determine the most suitable location for every CDL to prevent those types of catastrophic events.

Why Not Just Remove Some Steam Traps If They Are Not Needed?

Sites are sometimes interested to know which steam traps can be safely decommissioned for removal from the steam system; to reduce their maintenance responsibility. It can be a frightening question.

Each CDL designed into a system contains a steam trap at its core to discharge the condensate, as well as various piping and related components that represent considerable investment. Individual CDL often consist of up to a full-size tee on a distribution line, inlet strainer, isolation valves, steam trap, check valve, mud leg, blowdown valve, bypass line, tagging, and pipe insulation. The initial cost for designing and installing each original CDL represents a limiting factor that reduces redundant CDL unnecessary for safe and reliable long-term operation of the system. The design process for capital projects is budget-constrained to not implement unnecessary equipment; which means that design engineers pay careful attention to avoid redundant CDL. Therefore, it is a reasonable assumption that ALL originally-designed CDLs were determined to be necessary for safe and reliable plant operation.

Consider that the original Consulting Engineering firm was selected by the client site based on the firm's reputation for credible design capability, specialized to perform design work, using best practices as necessary to design a safe and reliable system. With full system knowledge, these consulting firm's designers designate the necessary CDLs. Many years later, how can a single individual with limited plant design knowledge decide to override that decision to decommission a CDL? From an objective viewpoint, because the internal operations of the steam system piping cannot be seen by individuals on site, what is the justification to overrule the original design of a registered Professional Engineering firm?

We Don't Want To Decommission Steam Traps, But We Don't Want To Fix Cold Traps Either?

Commonly, it is heard that budget priority is sometimes given to repair of Leakage Failure steam traps first, Cold traps second. Cold traps are Drainage Failures, the inability to discharge retained condensate from a system (**Figures 6 - 7**). This is a most serious situation that should be prevented from occurring because of the potential for severe ramifications, but site personnel often may not have sufficient data to justify changing the priority or valuating the risk for each Cold trap. Without an investment – return basis, such as is easily possible with the repair of Leakage Failures, Drainage Failure traps are sometimes carried over year after year, with the subsequent result of degrading the steam system over time from corrosion, erosion, hammer, and thermal effects.

Why Not Remove or Ignore All Steam Traps?

Perhaps a starting point to understand the importance of swift maintenance response for Drainage Failures would be to start at the opposite end of the topic by imagining a steam system with no steam traps to repair. Hypothetically, if the total cost to install a single Utility line CDL is $10,000 and a single Tracer CDL is $5,000; an unknowledgeable evaluator could make several estimations on paper.

For example, on a new construction project, if 100 Utility line and 500 Tracer CDLs are not installed, the capital investment for new construction could be reduced by $3.5 Million, which is a substantial amount. Furthermore, the cost of steam trap maintenance would be reduced to zero expense, so it could seem like a perfect situation to the estimator - provided that the system would work well. However, it is clear that such situation would lead to awful results, so a system with no steam traps can never be considered.

If both sides discussing the topic equally compromise, then 50% of the originally designed steam traps would be installed, saving $1.75 Million in capital investment. Does this argument still seem outrageous? Sure it does. This type iteration occurs naturally during design, so that the installed traps in a system can be considered as the most economically feasible design that met the client's requirements for new construction and long-term safety and reliability.

In the author's 2011 presentation to the IETC, "Use Available Data to Lower System Cost," a 25 Question Self-Help Checklist was provided. It is repeated below, but this time with the issues directly related Cold Traps shown by standard font with unrelated issues shown by a lighter, italicized font. This chart can facilitate an understanding of the types of issues that can occur from Drainage Failures.

A Self-Help Checklist With Focus on Cold Trap Issues

Here's a quick checklist of 25 questions to determine the real importance of steam at a site:

1. Are there multiple instances of external steam leaks from piping, especially flanges or valves?

2. Is water hammer present in the system?
3. Are multiple bypass valves opened around steam trap locations, particularly at process equipment (like heat exchangers)?
4. Are multiple blowdown or bleed valves open and discharging live steam to the atmosphere?
5. Is condensate at key process equipment being wasted to drain?
6. Are key steam-using process equipment suffering unexpected failures or shortened service life, particularly;
   - Loss of flare control or damaged flare tips?
   - Channel head gaskets leaking steam?
   - Turbine trips or blade plating?
   - Rotted heat exchange tubes / stratified coils?
7. *Is the "annual" steam trap testing program sometimes skipped for a year or two?*
8. *Is steam trap testing and replacement given a third-tier priority?*
9. Were less than 90% of all steam traps working properly after installing intended replacements following the last survey?
10. Are cold / blocked traps replaced as a second priority – with leaking traps replaced first?
11. Would the site like to improve the quality of the steam system, but there's never enough time or budget?
12. Does the site have a shortage of qualified personnel to replace steam traps?
13. Is there never enough time or resource to periodically blow down strainers / drip pockets?
14. Is there a "one size fits all" approach towards steam trap selection; using the same model for all drip and tracer applications?
15. Does the site remove strainer screens from steam traps to prevent blockage?
16. Is at least the same amount of steam produced today as 4 years ago?
17. In the past 3 years, has the plant suffered a major outage caused by retained condensate damage?
18. Do product lines or tracing lines freeze?
19. Is the sulfur area a nightmare?
20. Is the site worried about excessive CO2 emission?
21. Is the same amount of condensate (or less) recovered today as 4 year ago?
22. Is vent steam increasing?
23. Has the plant identified valuable recoverable condensate for which no project has yet been established?
24. Has the site suffered a water-induced flare-out in the past 3 years?
25. Are the majority of single stage turbines slow-rolled?

These are just some of the issues than can occur when a system has steam traps installed, but perhaps with lessened maintenance practice, including low priority to repair and subsequent carryover of Cold traps. Can it be imagined what could happen with reduced CDL locations? It leads to the question, "Just how many steam traps in an already-designed system can be decommissioned by site personnel in accordance with proper safety and risk mitigation considerations?" From the author's perspective, the correct answer is, "None", unless the original Consulting Engineering firm or a similarly-skilled firm re-evaluates the system and redesigns it for any possible updates to the piping or processes.

If this point were agreed, then site personnel would want to ensure the proper functioning of all CDLs possible, by performing Zero Reset with the maintenance response. In particular, any Cold trap not repaired has the same result as decommissioning the trap from the line – because a Cold trap is a Drainage Failure, and retained condensate will be left inside the system where it can create havoc in everyday operations.

EVENTS AND ECONOMICS

What Are Some Typical Effects of Cold Traps In A System?

Commonly, site users realize that Cold traps negatively affect the system, but sometimes there is difficulty to justify with investment – return economics. With a Leakage Failure, there is a quantifiable value estimated for each leaking steam trap. With a Cold Trap, the estimation is not as readily available, but it is still possible for a site to use historical data to provide a clearly quantifiable value estimate for each blocked trap. Once the average value is quantified, future investment to repair all cold traps becomes easily justifiable.

Relative to negative events caused by Cold traps, please consider the following typical safety and otherwise painful events;

- Personnel injury from flying pipe shrapnel
- Pipeline jumping off supports
- Plant Shutdown from Shattered Steam Pipe
- Plant Shutdown from Critical Turbine Compressor Failure
- Turbine Generator Failures
- Turbine Pump Failures
- Plant Shutdown from Analyzer failure
- Flare Tip or Ring Destruction
- Flare-out or Loss of Flare Control

- Frequent Utility Line Leaks from Erosion, Valve Packing, Fittings, or Flanges
- High Cost of Operations from Open Bypasses, Excessive Steam Leaks, Steam Bleeding, Wasted Condensate
- Process or Atomization Problems Caused by Injection of Wet Steam
- Gradual Deterioration of Vacuum System

Valuing the Painful Events

Plant shutdowns can easily exceed $1 Million per day, so any major equipment failure in single train sites is catastrophic. Here are some possible values for painful events based on reports from various sites (**Table 1)**:

Flare Nozzle Repair:	$ 750,000
Analyzer Failure:	$1 Million
Flare Failure:	$1.7 Million
Compressor Failure:	$3.6 Million
Main Turbine Failure:	$20 Million

Allocating Painful Events Cost Per Trap

With Leakage Failure traps, it is relatively easy to allocate avoided operational cost per investment because of the quantifiable cost per leakage event. Allocating cost per Drainage Failures from blocked traps requires a little more effort and access to historical data in order to have meaning to a particular site. Here is a process that can be used for gathering and using necessary data (**Tables 2 - 6)**:

- Determine historical painful events for past 3 – 5 years that were caused by retained condensate
- For repeat painful events, verify the average time between events
- Gather accurate cost information for each event
- Quantify the total number of steam traps located in each unit supplying the damaged equipment

Suppose that an Operating Unit had 360 steam traps, and that the entire plant site contained 8,000 total steam traps. In order to determine an average value for Painful Events damage caused by Cold traps, there are several steps. First, divide the historical cost associated with the damage by either the traps directly involved (which provides a really high value due to the small amount of traps), or the damage can be allocated over the total population of traps in a Unit (such as 360 traps, which provides a lower value). This provides a loss value per individual trap.

Next, divide that value by the number of years between events to estimate the loss value per trap year, allocated either by directly involved steam traps – or by the total traps in the Unit.

Third, list the annualized low values per trap for the Unit, and total the list (**Table 7)**. Admittedly, the examples show a lot of catastrophic events for a single unit. The examples focused on one Unit for simplicity. However, the Total of all historical Painful Events can be allocated over the entire trap population of 8,000 steam traps, and this provides an excellent basis to provide an individual loss value for Cold Traps (**Table 8)**.

CONCLUSIONS

Previously, site members may not have known how to provide a credible, estimated loss value for Cold Traps. Now, the methods provided herein can be used with a site's historical records for accurate and effective loss valuation to justify "Zero Reset" replacement. To answer the question, "What to do with Cold Traps, … and why?" - repair them with all haste to help avoid unnecessary occurrence of retained condensate and subsequent painful events that can shut down the plant.

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7. **Risko, James R.**, 2008. "Steam Traps – Operating Principles and Types," *Fluid Controls Institute*, Technical Sheet #ST107, Cleveland, OH, April. www.fluidcontrolsinstitute.org/pdf/resource/steam/ST107OperatingPrinciplesandTypes.pdf
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10. **"Steam Trap Management System,"** 2010. *TLV Co., Ltd.*, Kakogawa, Japan. www.tlv.com/global/US/products/070800.html
11. **Risko, James R**., 2008. "Ask the Experts – Optimize the Entire Steam System," *Chemical Engineering Progress*, New York, NY, February, p. 32. www.tlv.com/global/US/articles/optimize-the-entire-steam-system.html
12. **"What is Water Hammer,"** 2011. *TLV Co., Ltd.*, Kakogawa, Japan. www.tlv.com/global/TI/steam-theory/what-is-waterhammer.html
13. **"What Causes Stall to Occur,"** 2010. *TLV Co., Ltd.*, Kakogawa, Japan. www.tlv.com/global/US/steam-theory/stall-phenomenon-pt1.

Understanding Steam Systems

What To Do With COLD Traps …. And Why

Author: James R. Risko, C.E.M.

Presenter: Jonathan P. Walter, C.E.M.

IETC 2012
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Saturated Steam System

Do You Think Steam Is Saturated?

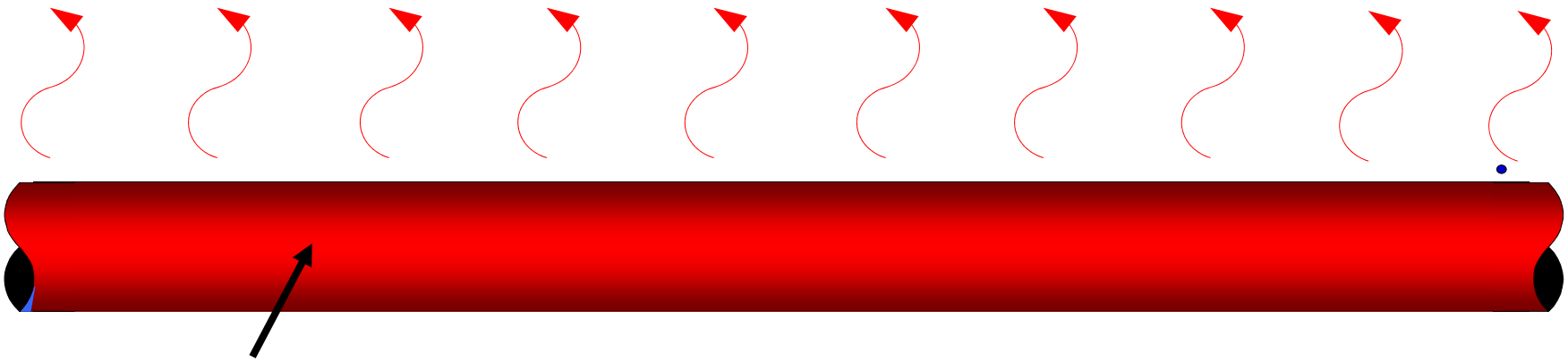


Figure 1

Wet Steam

Condensate entrained in steam flow = WET STEAM

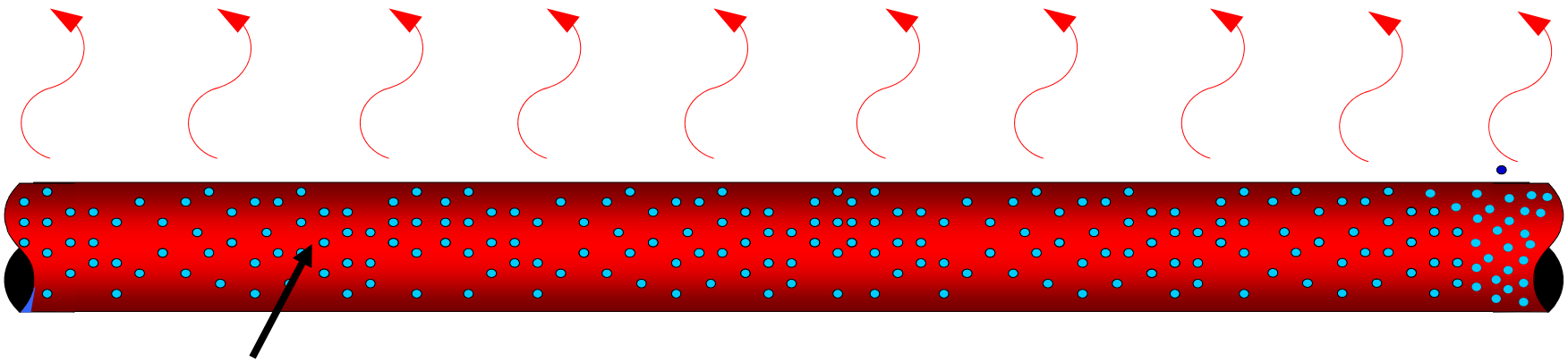


Figure 2

Condensate Slugs Can Form

Condensate Slugs Cause Water Hammer!

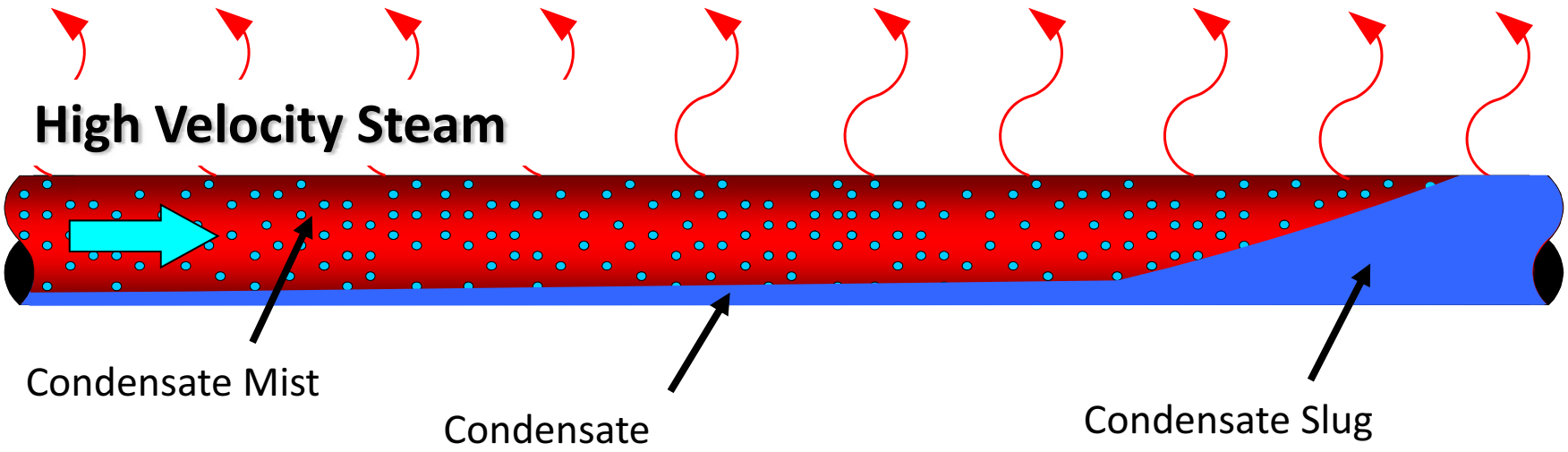
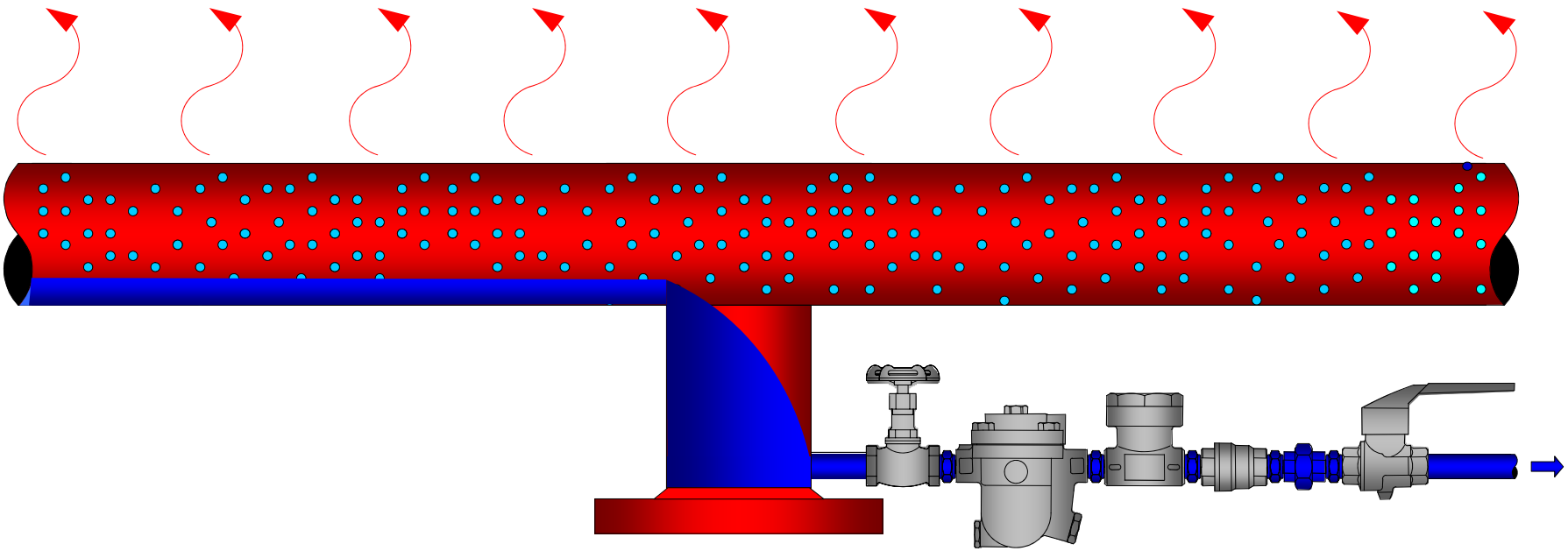


Figure 3

1st Priority

REMOVE CONDENSATE!



Condensate Discharge Location (CDL)

Figure 4

Condensate Caused Problems

Dangerous Events

From HPAC (Heating/Piping/AirConditioning)
http://www.kirsner.org/kce/media/pdfs/KirsnerHammer.pdf

Accidents can cause serious injury due to water hammer

Reduced Productivity

- Shutdowns
- Uneven heating
- Poor quality
- Corrosion

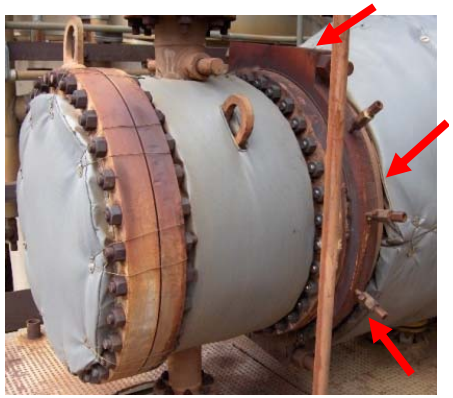
Retained Condensate Causes Various Problems in Steam Systems

Figure 5

Typical Painful Events

* Cracked Bleeder Or Drain Valves
* Bypass Steam

* Turbine Loss
* HX Channel Gasket Leaks



Flare Issues

* Loss of Control Or Flame-Out

* Tip Damage

* Flaring Fines

Steam Trap Population Analysis

Summary Performance

Total Failure Analysis by Number of Traps - Summary for /

Period	Category	Percentage	Annual Loss	Total	Good	Failed	No Service
Current	Leaking	6.95%	41.535	51	0	51	0
	Blowing	1.91%	31.609	14	0	14	0
	Good	68.66%	0	504	504	0	0
	No Service	14.25%	0	122	0	0	122
	Blocked	13.76%	0	101	0	101	0
	Low Temp.	5.31%	0	39	0	39	0
	Other	3.41%	0	25	0	25	0
	Summary	31.34%	73,144	856	504	230	122

Period	Category	Percentage	Annual Loss	Total	Good	Failed	No Service
Previous	Leaking	1.33%	9.716	9	0	9	0
	Blowing	0.29%	4.842	2	0	2	0
	Good	77.17%	0	524	524	0	0
	No Service	20.68%	0	177	0	0	177
	Blocked	11.78%	0	80	0	80	0
	Low Temp.	9.13%	0	62	0	62	0
	Other	0.29%	0	2	0	2	0
	Summary	22.83%	14,558	856	524	155	177

Failed Trap Priority List

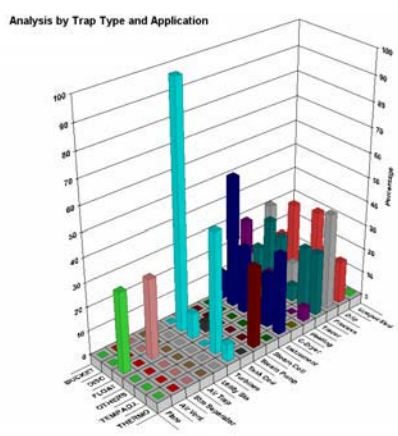
Failed Trap Report

Group By: Area No: Mixed Data

Trap Count: 28 Current Monetary Loss: 19,203 Current Steam Leakage: 3,841

Area-Trap ID	Model Name Trap Type Manufacturer	Application Priority Operation	Elevation Orientation	Connects. Type Size	Condensate Rate Recovered?	Installed Months Use Freq.	Pressure B. Press. Set Temp	Hr/Day Day/Yr Stm Cost	Trap Location	Test Results Judgement Inspection Date	Dollar Loss Steam Loss Leak Level
003-00509	MK21 THERMO GESTRA	Tracer Aux Continuous	Outdoor low horizontal	FN 16 RF 1.00	110 No (To drain)	9/18/1996 12-24 6	75 0 0	24 365 5.00		BLOWING Modified / Trap 10/1/1998	545 109 15
003-00507	MK21 THERMO GESTRA	Tracer Important Continuous	Outdoor low horizontal	FN 16 RF 4.00	110 No (To drain)	2/14/1995 24-36 6	75 0 0	24 365 5.00		BLOWING Modified / Trap 10/1/1998	545 109 15
003-00512	MK21 THERMO GESTRA	Tracer Critical Continuous	Outdoor low horizontal	FN 16 RF 1.00	110 No (To drain)	6/1/1994 36-48 6	130 0 0	24 365 5.00		BLOWING Modified / Trap 10/1/1998	545 109 15
003-00320	125-A5 FLOAT ARMSTRONG	Heat exch Aux. Continuous	Outdoor low horizontal	ANSI 400lb.RF 1.00	300 No (To drain)	10/26/1997 0-12 6	300 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	1,201 240 13
003-00310	125-A5 FLOAT ARMSTRONG	Heat exch Aux. Continuous	Outdoor low horizontal	ANSI 400lb.RF 1.00	330 No (To drain)	9/18/1996 12-24 6	300 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	1,201 240 13
003-00111	TD42 DISC SPIRAX SARC	Drip Aux. Continuous	Outdoor low horizontal	SCREW PT 0.50	220 No (To drain)	9/18/1996 12-24 6	300 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	961 192 13
003-00112	TD42 DISC SPIRAX SARC	Drip Aux. Continuous	Outdoor low horizontal	SCREW PT 0.50	220 No (To drain)	10/25/1997 0-12 6	300 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	961 192 13
003-00607A	ES8-12 BUCKET MIYAWAKI	Tank coil Aux. Continuous	Outdoor low horizontal	SCREW PT 1.00	110 No (To drain)	10/22/1997 0-12 6	130 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	961 192 13
003-00608A	ES8-12 BUCKET MIYAWAKI	Drip Aux. Continuous	Outdoor low horizontal	WELD SW 1.00	110 No (To drain)	10/21/1997 0-12 6	130 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	961 192 13
003-00510	MK21 THERMO GESTRA	Tracer Aux. Continuous	Outdoor low horizontal	FN 16 RF 1.00	110 No (To drain)	9/18/1996 12-24 6	130 0 0	24 365 5.00		LEAKS Modified / Trap 10/1/1998	401 96 13

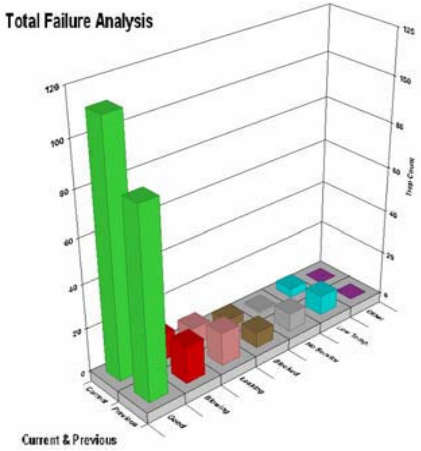
Data Investigation & Improvement Comparison



TrapManager - [Analysis - Untitled 1 *]

Site Analysis Reports Utilities Setup View Window Help

Category	Percentage	Monetary Loss	Total	Good	No Service	Failed	
Blocked	2.86	0	4	0	0	4	Current
Blowing	8.57	11,995	12	0	0	12	Current
Good	80.00	0	112	112	0	0	Current
Leaking	5.71	7,208	8	0	0	8	Current
Low Temp.	2.86	0	4	0	0	4	Current
No Service	0.71	0	1	0	1	0	Current
Summary	20.00	19,203	141	112	1	28	Current
Blocked	5.26	0	7	0	0	7	Previous
Blowing	12.78	19,901	17	0	0	17	Previous
Good	63.91	0	85	85	0	0	Previous
Leaking	11.28	6,575	15	0	0	15	Previous
Low Temp.	6.77	0	9	0	0	9	Previous
No Service	5.67	0	8	0	8	0	Previous
Summary	36.09	26,476	141	85	8	48	Previous



Typical Trap Population Health

Drain Condensate

Trap Steam

FAILURES

Drainage (Cold)	Leakage
13% = Reliability Issues	18% = Energy Issues

Good Traps	69 %

Steam Trap Population Action

Summary Performance

Total Failure Analysis by Number of Traps - Summary for

Period	Category	Percentage	Annual Loss	Total	Good	Failed	No Service
Current	Leaking	6.95%	41.535	51	0	51	0
	Blowing	1.91%	31.609	14	0	14	0
	Good	68.66%	0	504	504	0	0
Period							
Previous	Leaking	1.33%	9.716	9	0	9	0
	Blowing	0.29%	4.842	2	0	2	0
	Good	77.17%	0	524	524	0	0
	No Service	20.68%	0	177	0	0	177
	Blocked	11.78%	0	80	0	80	0
	Low Temp.	9.13%	0	62	0	62	0
	Other	0.29%	0	2	0	2	0
	Summary	22.83%	14,558	856	524	155	177

Identify Opportunities

Failed Trap Priority List

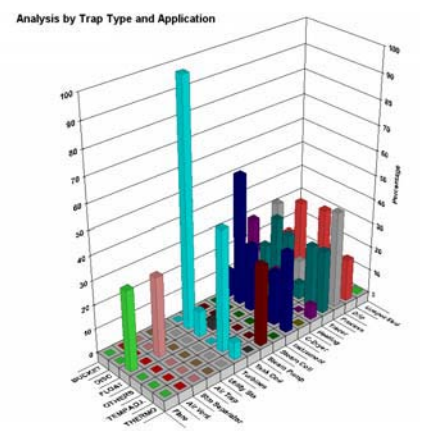
Failed Trap Report

Group By: Area No: Mixed Data

Trap Count: 28 Current Monetary Loss: 19,203 Current Steam Leakage: 3,841

Schedule Maintenance

Data Investigation & Improvement Comparison

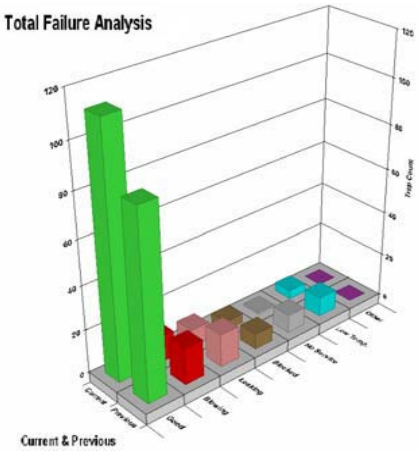


TrapManager - [Analysis - Untitled 1 *]

Site Analysis Reports Utilities Setup View Window Help

Category	Percentage	Monetary Loss	Total	Good	No Service	Failed	
Blocked	2.86	0	4	0	0	4	Current
Blowing	8.57	11,995	12	0	0	12	Current
Good	63.91	0	85	85	0	0	Previous
Leaking	11.28	6,575	15	0	0	15	Previous
Low Temp.	6.77	0	9	0	0	9	Previous
No Service	5.67	0	8	0	0	8	Previous
Summary	36.09	26,476	141	85	8	48	Previous

Perform Analysis of Failure Cause



2 Failure Modes

Steam Trap Failure Types

FAILURES

Blocked (Cold)	Leaking
Loss of Basic Function	Wasting Energy
No Condensate Discharge	Expensive Operation

Blocked Locations Cannot Drain!

Figure 6

2 Failure Modes – Population %

Steam Trap Failure Types

FAILURES

Drainage Failure	Leakage Failure
13%	18%
Cold - NO Drainage	Hot – Inefficient Drainage

Fix Blockage Failures First!

Figure 7

Cold Trap Issues

- **A 25 Question Checklist:**
  - Multiple Steam Leaks – Flanges, Piping, Packing
  - Water hammer
  - Bypasses or Bleeders Opened
  - Unexpected Process Shutdowns
  - <90% Steam Traps Functioning Normally
  - Cold Traps Replaced Last (or not at all)
  - Major Condensate-Induced Outage (3 Years)
  - Single-state Turbines Slow-rolled

Historical Loss Values

TABLE 1	
Failure Event	**Historical Value**
Flare Nozzle Replacement	$750,000
Analyzer Failure Plant Shutdown	$1,000,000
Flare-out Fine	$1,700,000
Gas Compressor Failure	$3,600,000
Main Turbine Failure	$20,000,000

Avoidable When Caused by Cold Traps

Cold Traps Value: Use Event Data

TABLE 2					
Failure Event	Term	Historical Value	# Traps	Cost / Trap	Annual Cost / Trap
Flare Replacement	3	$750,000	**360**	$2,083	**$694**
Flare Replacement	3	$750,000	**10**	$75,000	**$25,000**

Value Could be Higher Value if Restart Takes Several Days

Cold Traps Value: Use Event Data

TABLE 3					
Failure Event	Term	Historical Value	# Traps	Cost / Trap	Annual Cost / Trap
Analyzer Failure	2	$1,000,000	**360**	$2,778	**$1,389**
Analyzer Failure	2	$1,000,000	**1**	$1,000,000	**$500,000**

Value Could be Higher Value if Restart Takes Several Days

Cold Traps Value: Use Event Data

TABLE 4					
Failure Event	Term	Historical Value	# Traps	Cost / Trap	Annual Cost / Trap
Flare-out Failure	1.5	$1,700,000	**360**	$4,722	**$3,148**
Flare-out Failure	1.5	$1,700,000	**10**	$700,000	**$113,333**

Multiple Flare-outs Can Result in Escalating Fines

Cold Traps Value: Use Event Data

TABLE 5					
Failure Event	Term	Historical Value	# Traps	Cost / Trap	Annual Cost / Trap
Turbine Failure	2	$3,600,000	**360**	$10,000	**$5,000**
Turbine Failure	2	$3,600,000	**4**	$900,000	**$450,000**

A Unit Compressor May Allow Operation of a Second Train

Cold Traps Value: Use Event Data

TABLE 6					
Failure Event	Term	Historical Value	# Traps	Cost / Trap	Annual Cost / Trap
Main Turbine Failure	5	$20,000,000	**360**	$55,556	**$11,111**
Main Turbine Failure	5	$20,000,000	**20**	$1,000,000	**$200,000**

Everything Stops When a Main Failure Occurs

Allocated Event Cost / Trap Year

TABLE 7	
Failure Events	**Annual Cost / Trap** (360 Traps in Unit)
Flare Nozzle Replacement	$694
Analyzer Failure Shuts Plant	$1,389
Flare-out Fine	$3,148
Gas Compressor Failure	$5,000
Main Turbine Failure	$11,111
TOTAL	**$21,342**

Lots of Opportunity… to Lower System Cost

Population Annual Event Cost / Trap

TABLE 8	
Failure Events	**Annual Cost / Trap**
360 TRAP TOTAL	**$21,342**
8,000 TRAP TOTAL	**$960**

Fix Blocked Traps… as 1st Priority!

Understanding Steam Systems

Thank You

James R. Risko, C.E.M.

Jonathan P. Walter, C.E.M.

IETC 2012
34th Industrial Energy Technology Conference

Why Pressure Reducing Valves (PRV's) are costing you money

Andrew Downing, Dresser-Rand

Abstract

Throughout many manufacturing facilities, colleges, commercial sites or industrial complexes, pressure reducing valves (PRV's) provide a cheap, reliable method to produce low pressure steam from a high pressure source in order to meet a process requirement or heating load. This simple method of expanding steam in a PRV creates no work and supplies the same heat content available in the high pressure steam at a more manageable low pressure. What if you could produce the same low pressure steam while saving hundreds of thousands of dollars on your electric bill and taking only a minimal hit in the available heat content? Why let steam down and get no benefit from it, when putting it through a low pressure steam turbine coupled to a generator would produce the heat you need for process with the byproduct of onsite electrical generation.

This paper analyzes the costs, concerns and benefits of replacing a pressure reducing valve with a Steam Turbine Generator set including illustrations of what the marginal fuel increase would be in order to take advantage of the added benefits of clean, cheap and reliable onsite power production.

Introduction

Any and every industry that operates steam boilers at a pressure greater than required for a process or a heating load utilizes pressure reducing valves (PRV's). This common tool has been around as long as high pressure boilers and provides an extremely efficient method for the heat requirements of a thermal load at lower operating pressures. This paper explains why operating your facility in this manor, utilizing large flow pressure reducing valves, could be costing you hundreds of thousands of dollars annually in possible energy savings.

The core purpose of the steam PRV is to reduce operating pressure to meet the maximum allowable operating pressure (MAOP) of any given process. As facilities begin to grow in process requirements and product output, services requiring steam tend to move farther from the central boiler plant, PRV's allow process engineers to operate a high pressure steam boiler and transport steam to various locations around their facility with no concern of pressure loss. Losses due to distance are easily accounted with high pressure steam lines and the pressure let down is precisely controlled at site of use.

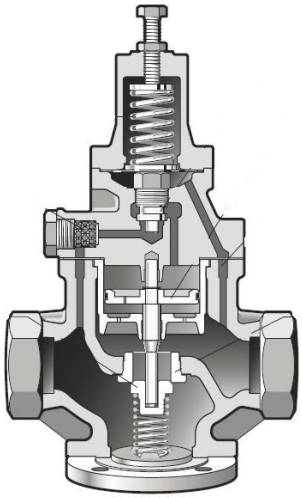


Fig. 1- Pressure Reducing Valve (PRV)

The method of expanding steam through a PRV produces the same heat at the exit as inlet, but generates no work. PRV's are an isenthalpic process meaning that enthalpy is conserved across the valve. In simple terms 1,204 Btu/Hr of 400 psig dry and saturated steam into a PRV will drop to your required pressure (for an example, 50 psig) still at 1,204 Btu/Hr out. In contrast with a PRV, a backpressure steam turbine (figure 2) will still give the pressure drop but consumes a small percentage of the enthalpy to generate work, spinning a shaft. Coupling the turbine to an electric generator makes that work not only useful, but transferable to other locations of the facility.

Using Backpressure steam turbines in place of PRV's is not a new concept. Back pressure Steam Turbine Generators sets utilize some of the most well established technology available. They were commonly used for onsite power generation some 100 years ago, but as electricity prices dropped, there was no need to integrate them into most plant processes. That was then, and now, electricity prices have steadily increased over the years. Replacing a PRV is not a complicated process and produces real savings.

For our analysis, a company is performing a steam audit of their facility and examining the economic and operating variables inherit with replacing large PRV's with Back Pressure Steam Turbine Generator sets. This paper takes you through estimating the impact associated with:

- Sizing the correct steam turbine
- Generating electricity to offset purchased electricity
- Increased fuel consumption

We will demonstrate that the two locations identified would benefit from a single stage (Dresser-Rand RLHA 24 turbine) and a multistage (Dresser-Rand R-Frame)

Knowing your current steam load / electrical distribution system

Before investing several thousand or potentially millions of dollars on a turbine generator set, potential users should perform a complete audit of their existing steam system and the facility's electrical consumption. The data gathered will be used to determine if there is an application and what the best equipment solution would be. By isolating and monitoring key PRV's throughout the facility, plant personal will be able to calculate potential payback scenarios along with predicting installation and operation costs (if there are suitable locations for installation of a system in close proximity to the PRV). A PRV's sole purpose is to expand steam in order to provide required heat to process at lower pressure. Back pressure steam turbines are designed fundamentally the same way, operating as a heat to process first device that also generates electricity as a byproduct. Just like PRV's, Steam turbines have optimal operating ranges, this consists of a performance curve (figure 2a, 2b) and depending on the model, a specific operating range.

Figure 2 – A Dresser-Rand RLHA Backpressure steam turbine packaged by Turbosteam LLC

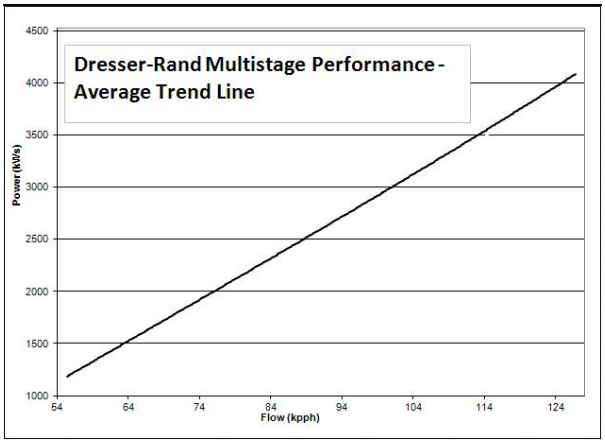


Figure 3a – A Dresser-Rand R-frame multistage/multivalve turbine can be sized for a greater amount of steam flow and operating range. The increased size and number of stages provide a more efficient machine.

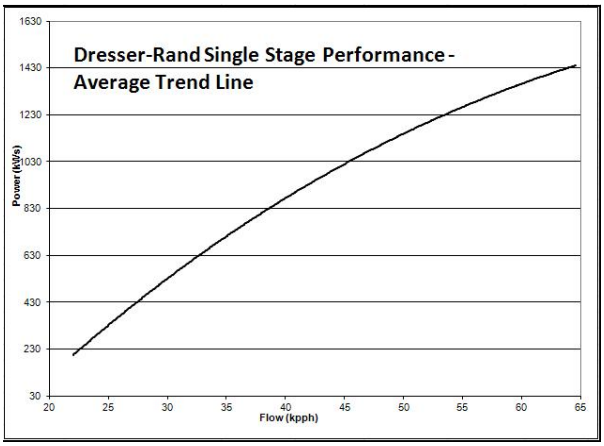


Figure 3b – A Dresser-Rand RLHA 24 / 700 series single stage turbine is ideal for smaller applications where cost and low steam flow need to be optimized.

Our example facility is a large industrial complex that utilizes multiple boilers with several high and low pressure steam users. This example illustrates design analysis with differing high pressure steam supply at opposite locations in the same facility. Quite often, during expansions, industrial and commercial facilities may purchases additional boilers that operate at higher or lower pressures than existing equipment. The analysis contained in this paper would be the same for any size facility ranging from a single boiler to multiple boilers.

Upon completion of an audit, plant personnel have located two potential PRV's supplying low pressure steam to processes from two separate high pressure steam distribution lines. Both locations have significant electrical loads currently supplied by the facilities internal electrical distribution system. For analysis purposes, we will call the first site *'Location A'* and the second *'Location B'*. After a preliminary analysis, these two locations provide the most feasible opportunities for onsite power generation using a Steam Turbine Generator system.

The qualities to identify for a suitable location are:

- Access to utility services, such as low voltage power sources, water, compressed air
- Open area suitable for installation of a turbine generator set and potential outhouse for controls/switchgear
- Switchboard or power line tie in points with suitable load for the potential power generation
- Proximity to both the high and low pressure steam lines, preferably with in the vicinity of the PRV to be replaced

Analyzing your potential – Single Stage Opportunity

After a preliminary analysis has been completed, plant personnel need to compare the operation of their current PRV versus the substitution of a Steam Turbine Generator set. In both locations the PRV will not be removed, but bypassed during normal operation through the steam turbine. This allows the operator to isolate the turbines for service while ensuring the process continues to receive low pressure supply.

Based on steam process requirements, *Location A* currently utilizes 50 psig steam that is let down from a 400 psig dry/saturated high pressure header. The equipment that best suits these conditions would be a single stage, axial flow, horizontally split steam turbine coupled to a gear reducer and generator. A single stage turbine was selected due to considerations of installation size and cost. Process engineers have installed a steam meter just upstream of the PRV to record seasonal variations in the steam flow (figure 3a,3b)

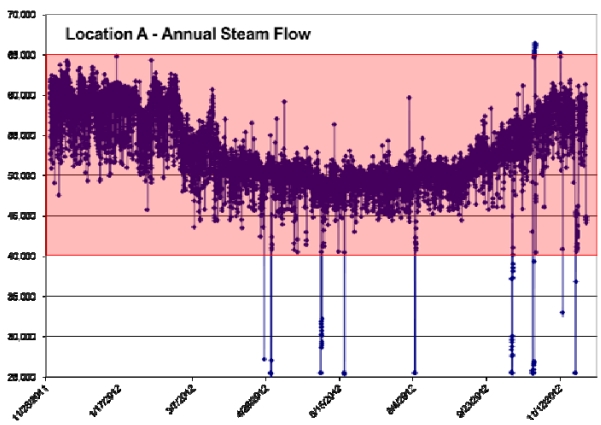


Figure 4a – Steam flow charted for one year with ideal turbine operating range highlighted in red

At any given time the plant operation needs between ~40,000 and ~65,000 lbs/hr of 50 psig steam. To compare a PRV against a turbine, we analyze the heat requirements of the process instead of the actual operating pressure. In many cases, the pressure is arbitrary (as long as it is at or below the MAOP). As with a PRV, the exhaust pressure can be adjusted to fit the requirements of the process. Critical to the facility is the heat content (Enthalpy) of the steam. For this example, we have isolated the highest and lowest heat requirements for process at this location (based on the historical steam flow data for 1 year):

Steam Flow	Btu/lbm	Heat (Btu/hr
65,000	1,179.10	76,641,500
45,000	1,179.10	53,059,500

From the table above, we have to match the heat requirement established with a Steam Turbine Generator set. Due to the electrical generation produced by the Steam Turbine, the enthalpy of the exhaust of the turbine is going to be below that of a PRV, the differential becomes our fuel make up calculation which we will determine after calculating electrical production.

The first stage in calculating the potential savings is realizing what the electricity generated from the turbine generator set will be. The system will offset a percentage of purchased electricity which equates to a dollar value. This facility has assumed that each kw-hr of electricity has a blended electric cost (blended refers to all energy, demand, and other service charges added together) of $0.07/kWh.

Combining the historical steam flow from the facility with a turbine performance curve will give you expected power outputs (and in turn expected savings) over a predefined operating range. For the single stage turbine, graphically representing the turbine performance curve will allow you to input a steam flow and calculate an expected power output. As with any theoretical model, the greater the measured points on the curve, the higher the probability of predicting the performance will be. Based on the turbine selection, we have calculated the operating performance of to be:

$$y = x^3 - x^2 + X - B$$

$$R^2 = 98\%$$

Where ‘y’ is the expected power, ‘x’ is the steam flow (simplified to kpph for this formula),

B is the y intercept of the graph and our ‘R^2’ is the predicted accuracy of the equation.

Plant Operating Information		Electric Generation Savings (Gross Calculations)		
Date/Time Stamp	Steam to process (Lbs/hr)	Turbine Power (kWs)	Electricity at Terminals (kWe)	Gross Electric Savings ($$)
2/15/12 12:00	58,575	1337.8	1258.2	$ 88
2/15/12 13:00	55,236	1270.1	1194.5	$ 84
2/15/12 14:00	60,762	1378.7	1296.7	$ 91
2/15/12 15:00	58,815	1342.4	1262.6	$ 88
2/15/12 16:00	52,783	1216.2	1143.8	$ 80
2/15/12 17:00	59,089	1347.7	1267.5	$ 89
2/15/12 18:00	59,345	1352.5	1272.1	$ 89
2/15/12 19:00	58,286	1332.2	1252.9	$ 88
2/15/12 20:00	58,639	1339.0	1259.4	$ 88
2/15/12 21:00	58,578	1337.9	1258.3	$ 88
2/15/12 22:00	58,201	1330.5	1251.4	$ 88
2/15/12 23:00	57,804	1322.7	1244.0	$ 87
2/16/12 0:00	59,181	1349.4	1269.1	$ 89
2/16/12 1:00	52,436	1208.3	1136.4	$ 80
2/16/12 2:00	56,518	1296.9	1219.7	$ 85
2/16/12 3:00	55,907	1284.2	1207.8	$ 85

Figure 5 – Using measured steam flow data and expected turbine performance plant engineers can estimate turbine power output. Before electric output can be estimated, the shaft power of the turbine must be multiplied by inefficiencies in the drive train (in this case a speed reduction gear and a generator) to arrive at Kilowatt Electric (kWe).

Operating the turbine does come with a small cost. We discussed that the operation of a PRV is an Isenthalpic process (Enthalpy in = Enthalpy out), but the steam turbine has converted a small percentage of that inlet enthalpy to work to make electric power, generating the savings above. In this case, the input to the turbine is 1,204 Btu/lbm, but the exhaust enthalpy (depending at what steam flow the turbine is operating at) can range from 1,169 Btu/lbm to 1,126 Btu/Lbm. The 3% to 6.5% enthalpy reduction is what generates the power shown in figure 4. This number varies because turbines do not maintain the same efficiency (and therefore exhaust enthalpy) across their entire operating range. To obtain a true net value, we have to factor in additional boiler fuel costs associated with operating the Steam Turbine Generator.

Calculating the increase in fuel consumption follows the same logic as calculating the electric savings. At each operating point the exhaust enthalpy varies based on inlet enthalpy and turbine efficiency at that operating point. The higher a turbines isentropic efficiency, the more enthalpy it is able to convert to electric power, the opposite is true as well. As a turbine becomes less efficient it converts less enthalpy to power. Based on the turbine selection, we have calculated the exhaust enthalpy formula to be:

$$y = -X^3 + X^2 - X + B$$

$$R^2 = 96\%$$

Where ‘y’ is the expected enthalpy, ‘x’ is the steam flow (simplified to kpph for this formula), B is the y intercept of the graph and our ‘R^2’ is the predicted accuracy of the equation.

From the above formula, we have to make up between 2 MM and 3 MM Btu/hr of heat. For example purposes, we will assume that the cost of 1 MMBtu of fuel is $6.50. Assuming a boiler efficiency of 85% and that we are able to keep 180 btu/lb of heat through the boiler feed water supply, we can calculate our expected hourly fuel increase. Our net savings becomes our anticipated electric savings minus our increase in fuel cost. This value is actually lower than what can be expected since we have increased the fuel rate to make additional steam which in turn will go through the turbine to make additional power.

Economic Variables		
Boiler Efficiency	85%	
Average Fuel Cost	$ 6.50	MMBtu
Blended Electric Cost	$ 0.070	kWh

Month	Electric	Fuel	Net
December	$ 65,481	$ 16,372	$ 49,109
January	$ 64,837	$ 16,275	$ 48,561
February	$ 60,062	$ 15,121	$ 44,941
March	$ 59,201	$ 15,240	$ 43,961
April	$ 53,543	$ 13,870	$ 39,673
May	$ 55,612	$ 14,477	$ 41,136
June	$ 51,324	$ 13,320	$ 38,004
July	$ 54,897	$ 14,311	$ 40,585
August	$ 54,877	$ 14,251	$ 40,627
September	$ 55,819	$ 14,453	$ 41,366
October	$ 58,634	$ 14,872	$ 43,763
November	$ 58,032	$ 14,608	$ 43,424
	Total	$	515,149.88

Figure 7 – Analyzing the steam data for the entire year will provide a window into expected savings generated had the Steam Turbine Generator set been installed during the measured operating range.

The greater the differential between the cost of electricity and the cost of boiler fuel, the greater the expected savings. Turbine generator sets are designed to operate continuously and can be engineered to automatically control part load efficiency at varying steam loads to optimize performance.

After completion of the analysis, the first location at the facility could benefit with over $510,000 in annual electric savings based on the installation of a single stage turbine generator set.

Analyzing your potential – Multistage Opportunity

The logic used in optimizing and calculating savings for the single stage turbine is identical to the multistage turbine. Due to the higher efficiency inherit to multistage turbines, the power output tends to be greater as well as the make up fuel requirements.

Based on steam process requirements, *Location B* currently utilizes 120 psig steam that is let down from a 600 psig / 750F high pressure header, which ideally operates in a multistage turbine frame based on cost and size of unit. The equipment selected is a Dresser-Rand R frame multistage/multivalve design, horizontally split with axial inlet and exhaust. Process engineers have installed a steam meter just upstream of the PRV to record seasonal variations in the steam flow (figure 8)

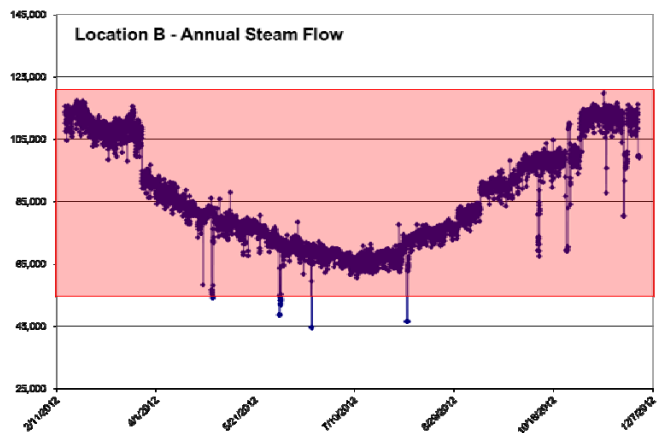


Figure 8 – Steam flow charted for one year with ideal turbine operating range highlighted in red

Using the same methodology as *Location A*, a steam flow meter is installed upstream of the PRV to record the season swing of the steam flow. Due to the significantly high and low steam flow requirements, a single stage turbine is not suitable for installation.

At any given time the operation needs between ~60,000 and ~120,000 lbs/hr of 120 psig steam. The current location operates a PRV with a de-superheater (a device that reduces the steam temperature from superheated steam to saturated steam). At full flow, the de-superheater needs to input ~32 GPM of water in order to temper the steam for use in process. As an added benefit of the installation of a steam turbine, this added water cost is eliminated. Based on the

high and low operating points, the heat requirements are:

Steam Flow	Btu/bm	Heat (Btu/Hr)
120,000	1,378.90	165,468,000
60,000	1,378.90	82,734,000

Although everything for this location is on a larger scale in terms of power output and steam flow, the fundamental calculation and engineering requirements remain the same. The added benefit of this location is the superheat available to the turbine. The increased Btu's available in superheat provides a greater enthalpy drop across the turbine which translates to more power generation. With the installation of a steam turbine, a de-superheater is not required as all the superheat is consumed by the turbine and converted in to power. Using the same methodology as *Location A*, we calculate the turbines power and enthalpy performance formulas.

Power calculations:

$$y = x^3 - x^2 + X - B$$

$$R^2 = 98\%$$

Where 'y' is the expected power, 'x' is the steam flow (simplified to kpph for this formula), B is the y intercept of the graph and our 'R^2' is the predicted accuracy of the equation. Enthalpy calculations:

$$y = -X^3 + X^2 - X + B$$

$$R^2 = 96\%$$

Where 'y' is the expected enthalpy, 'x' is the steam flow (simplified to kpph for this formula), B is the y intercept of the graph and our 'R^2' is he predicted accuracy of the equation.

Economic Variables		
Boiler Efficiency	85%	
Average Fuel Cost	$ 6.50	MMBtu
Blended Electric Cost	$ 0.070	kWh

Month	Electric	Fuel	Net
December	$ 57,404	$ 24,179	$ 33,225
January	$ 53,338	$ 23,809	$ 29,529
February	$ 102,712	$ 32,558	$ 70,154
March	$ 154,768	$ 43,435	$ 111,333
April	$ 108,745	$ 35,901	$ 72,844
May	$ 98,982	$ 33,965	$ 65,017
June	$ 78,480	$ 28,713	$ 49,767
July	$ 79,272	$ 28,371	$ 50,901
August	$ 92,409	$ 32,430	$ 59,979
September	$ 116,593	$ 37,371	$ 79,222
October	$ 139,277	$ 41,299	$ 97,977
November	$ 156,795	$ 42,616	$ 114,178
	Total	$	834,127.41

Figure 9 – As with *Location A* the savings are calculated based on a blended electric and fuel cost.

After completion of the analysis, the second location at the facility could benefit with over $830,000 in annual savings based on the installation of a multistage Steam Turbine Generator set.

An added value of installing the system is the reduction in water consumption by the de-superheater, saving the facility 32 GPM of consumption along with the additional boiler blow down and chemical requirements of the condensate return.

Conclusions

High pressure boilers have become a common place tool to provide heat in the form of steam to processes ranging from heating/cooling to industrial applications. At one point in our history, operating a backpressure Steam Turbine Generator set at an industrial or commercial facility was common place. With the advancements of electrical grids, the need for generating power onsite in the form of Combined Heat and Power (CHP) has

diminished. In the past, electricity was cheap, abundant, a resource that was taken for granted. Since 2000, electricity prices have increased at a 2.5 percent annual rate, which is slightly higher than the 1.99 percent rate of inflation. [1] Installing a backpressure Steam Turbine Generator set in place of a PRV hedges future electric rate increases as you will have a predetermined amount of power generated onsite. The fact that you have to operate the boilers to generate steam for a process ensures you will always have the ability to operate the steam turbine, the only significant cost in operating is the additional fuel required to make up the loss of enthalpy.

For this fictional location, with the installation of two separate turbine genarator sets, the operators are able to reduce their overall electric bill by more than $1.3M a year. Backpressure turbine generator sets typically range anywhere from a 100 kW to 20 MW and the economics of installing one is wholly dependent on fuel costs and electricity rates. If your facility has multiple PRV's, but equipment/installation costs are an issue, fund just one project and with the savings generated, you have the potential for future funding of all PRV replacments. Keys to a succesful project are properly evaluating the steam load profile and steam conditions to ensure the conceptual design will match actual conditions. Doing so will provide a project that will generate electricity and savings for years to come.

	Location A	Location B
Inlet Pressure	400 psig	600 psig
Inlet Temperature	448 F	750 F
Exhaust pressure	50 psig	120 psig
PRV Steam Flow	65,000 lbs/hr	120,000 lbs/hr
PRV Enthalpy	1,204.7 Btu/lb	1,379.6 Btu/Lb
PRV Heat Load	78,305,500 Btu/hr	165,552,000 Btu/hr
Turbine Steam Flow	69,506 Lbs/hr	130,150 Lbs/hr
Turbine Enthalpy	1126.6 Btu/Lb	1,272 Btu/Lb
Turbine Heat Load	78,305,500 Btu/hr	165,552,000 Btu/hr
TG set rating	1,390 kWe	3,890 kWe
Electric Savings	$ 692,319	$ 1,238,774
Fuel Cost	$ 177,169	$ 404,647
Net Savings	$ 515,150	$ 834,127

Figure 10 – A side by side comparison shows the increase in steam flow necessary to equal the same heat to process. As the throttle steam flow decreases, the makeup fuel and additional steam required decreases.

[1] "Rising Electricity Costs: A Challenge For Consumers, Regulators, And Utilities". May 2006, Edison Electric Institute

http://www.entergy.com/global/documents/utility/industry/EEi_rising_electricity_costs.pdf

Intelligent Efficiency: the Next Generation of Energy Efficiency[1]

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ABSTRACT

Information and communication technologies (ICT) and their enabling technologies are responsible for a significant portion of energy efficiency improvements in the past decade. Sensors and controls, the internet, and semiconductor technologies have already changed the way we use energy and interact with other people: how we work, shop, and have fun. But that is only the start. As highly efficient technologies begin to interact with each other and respond in real time to their environment, there will be a structural change in how we use energy.

This paper explores the next generation of energy efficiency: what we call *intelligent efficiency*. Building on recent work in this area, this paper will define intelligent efficiency and provide specific case studies to illustrate its impact. This paper will focus on the manufacturing sector, but examples include commercial building energy management, industrial automation, and transportation infrastructure. This paper will discuss how these technologies work together synergistically to reach new levels of efficiency, allowing us to not only save energy, but to improve the economy and create jobs. Finally, the paper will identify barriers and policy solutions to intelligent efficiency achieving even greater savings and economic benefits.

INTRODUCTION

Energy efficiency has been a major contributor to meeting the United States' energy needs for the past four decades, and numerous studies suggest that the potential for new energy efficiency remains enormous (11, 14). A significant portion of our past efficiency gains came from improvements in the individual products, appliances and equipment that use energy, whether the light bulbs that illuminate our world, electric motors that drive our equipment, or the cars and trucks that move us and our things. But we are reaching a point of diminishing returns from focusing on component efficiency. The nature of our future energy efficiency potential will be very different from what we have seen in the past decades. Although discrete, device-level improvements in efficiency will continue to play an important role, they are not sufficient to scale up efficiency dramatically enough to meet the challenges we will confront in future years.

Ultimately, making significant gains in energy efficiency depends less on the devices themselves and more on how we use the things and services we demand. These system efficiencies require a combination of technology and behavioral "intelligence" that interacts dynamically with its surroundings. The efficiency of a system is a function of 1) how its energy use is managed within the technologies and how they interact with one another, and 2) the choices made by the humans involved. Over the past three decades, elements of this dual "intelligence" have been converging to produce something new and unique. We characterize this convergence of technology and behaviors that can form the basis of a thriving economy into our resource-constrained future as *intelligent efficiency.*

WHAT IS INTELLIGENT EFFICIENCY

Intelligent efficiency is a systems-based, holistic approach to energy savings, enabled by information and communication technology (ICT) and user access to real-time information. Opportunities for *intelligent efficiency* exist along a continuum between technology and human behavior. At one end of the spectrum are measures in which consumer decisions play the dominant role in determining efficiency. At the other end, you might have a fully automated system controlling end-use devices, where human input, other than in programming and commissioning the system, is not needed—or even desired. Thus, *intelligent efficiency* "invites" individuals' engagement with a system when this improves

[1] This paper is drawn from a more comprehensive forthcoming report, tentatively titled *A Defining Framework for Intelligent Efficiency*. ACEEE 2012

efficiency and "disinvites" engagement when it does not.

Key enablers of *intelligent efficiency* have been the emergence of affordable sensors and controls, computational capability, the ability to share large amounts of data, and a growing awareness among energy researchers and practitioners of what consumers want and how they interact with the technology that they increasingly depend on. Information and communication technology (ICT), and the access to near real-time information that this technology enables, provides a foundation for *intelligent efficiency* that allows systems to be optimized to a degree never before seen. By intelligently combining efficiencies achieved by either technologies or human behavior, systems built around *intelligent efficiency* can balance the needs of the user with reduced energy usage to achieve efficiencies that dwarf those obtained through a focus solely on the devices themselves.

Types of Intelligent Efficiency

We have developed a framework for defining and characterizing *intelligent efficiency* (Figure 1) based on the approach to achieving energy savings rather than by the sector of the economy. In fact, each type of *intelligent efficiency* spans all sectors of the economy, including our homes, buildings, factories, transportation, institutions, and the electric power grid, and across all types of energy, including electricity, natural gas, and oil. We group *intelligent efficiency* into three broad (and frequently overlapping) categories:

- People-Centered Efficiency (Real-Time Feedback)
- Technology-Centered Efficiency (Automation and Optimization)
- Service-Based Efficiency (Dematerialization or Substitution)

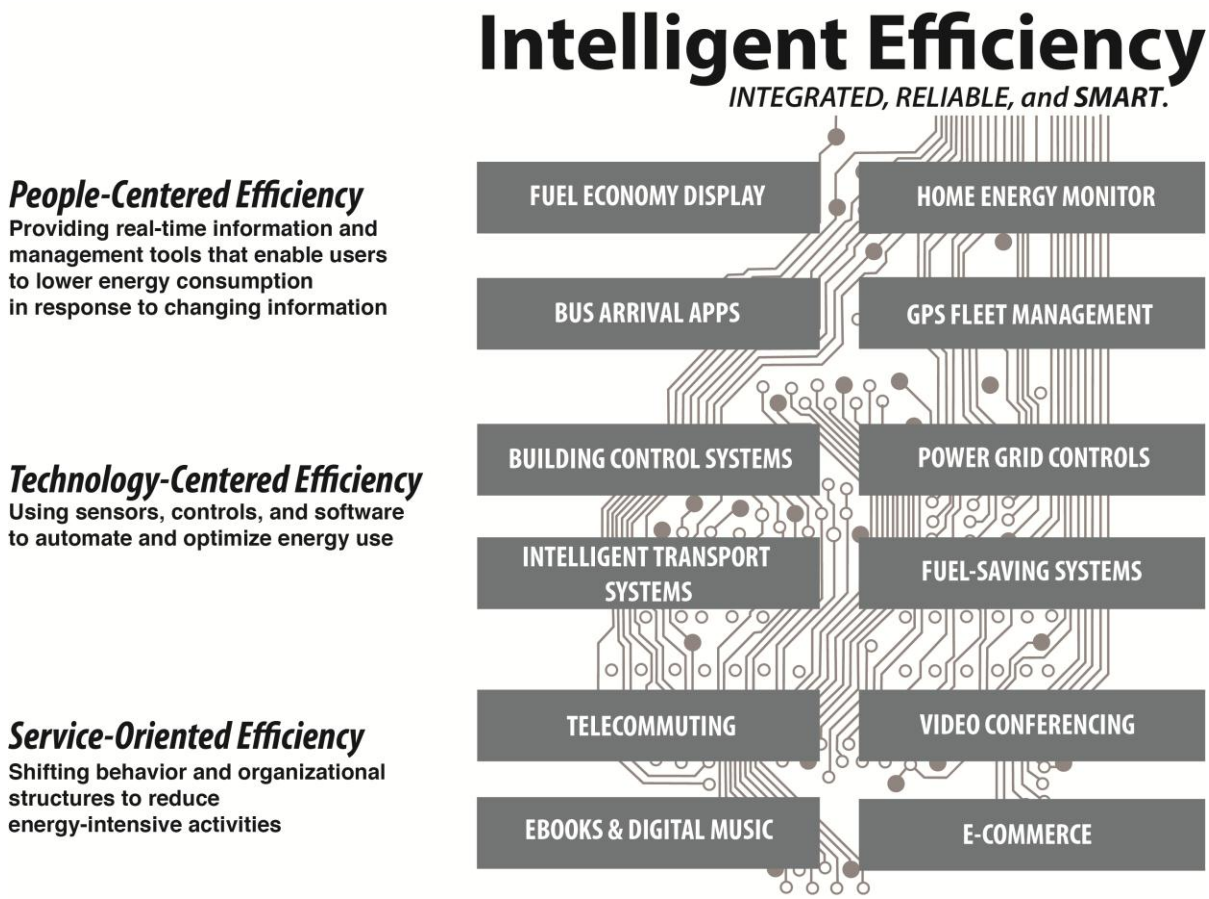

Figure 1: Framework for Intelligent Efficiency

Communication and energy infrastructure, such as a campus of buildings, an entire city, or the electric power grid, allow a scaling up of intelligent efficiency, amplifying the benefits by coordinating all systems. Through intelligent efficiency, smart grids, cities, transportation systems, and communications networks can become the new normal across the United States and will undergird national and regional economies that, even in the face of increasingly scarce resources, grow and thrive.

1. People-Centered Efficiency (Real-Time Feedback).

People-centered efficiency adds sources of real-time feedback—making energy use visible—in order to invite more human decision making into the quest for energy efficiency. When consumers—whether home owners, building or facility operators, or vehicle drivers—have access to clear and relevant real-time[2] information, they can modify their behaviors in ways that save energy while accomplishing the task just as well, or better. Examples of enhanced, real-time feedback include smart meters with display capability, in-home energy displays, lobby displays in large buildings, smart phone applications, and fuel-economy displays in vehicles.

Much recent research has looked at the energy savings possible through access real-time feedback. A 2010 report by ACEEE documents numerous programs that use behavioral feedback mechanisms to achieve energy savings that hold up to rigorous evaluation, measurement, and verification (EM&V) standards (4). While the most visible implementations of buildings-oriented people-centered efficiency have focused on residential users, we are beginning to see similar program emerge in large buildings, and even integrated across cities. In the transportation sector, technologies such as "smart" global positioning systems (GPS) that propose alternative routes and instantaneous dashboard displays showing real-time miles-per-gallon readings help drivers save fuel by maintaining efficient speeds and avoiding traffic congestion. Similarly, network-connected GPS navigation systems can give instructions to a delivery truck driver on the shortest route to cover all of his deliveries. Public transit users benefit from real-time information on bus and train arrivals, for example, via smart phone applications that allow users to optimize their transportation routes and thus save time and remove a barrier to choosing a more efficient mode of transportation.

2. Technology-Centered Efficiency (Automation and Optimization)

Activities in this category require human intervention at the design stage, with the day-to-day operation of the systems being coordinated nearly exclusively by carefully designed groups of technologies, for example, sensors, controls, computer simulation, and communications networks. Here, "smart" technologies remove much of the need for direct human intervention and finely orchestrate the operation of the systems' components to achieve efficiencies impossible to come by through human oversight alone.

Technology-Centered Efficiency in Manufacturing: In today's manufacturing sector, *intelligent efficiency* means integration. Process automation, enterprise resource planning, and energy management standards each represent a consolidation of information and practices that that allow more "intelligence" and control in industry. But more importantly, these trends are beginning to converge, pushing *intelligent efficiency* in manufacturing to new frontiers.

The manufacturing sector has been on the path of technology-centered *intelligent efficiency* for decades, dating back to the first widespread use of sensors and controls technologies in the 1980s. The technology gradually became less expensive and more sophisticated, allowing for increasingly complex automated feedback loops. In the 2000s, closed loop controls for support equipment such as boilers became common, allowing systems to optimize themselves as their environments changed, with little human interaction.

As experience with these controls increases, this technology will be further applied to process equipment. While process equipment is responsible for a large portion of energy consumption in industry, manufacturers are very risk averse when considering changes because these systems are directly responsible for the quality of the final product. In 2000, ACEEE released a report on emerging technologies in the industrial sector, and found that process sensors and controls could realize energy savings of 4-17% in certain applications (2). Using those sensors and controls along with closed-loop feedback would increase their savings potential much more. Increased feedback and controls could also

[2] We use the term "real-time" as a lay term. We understand that dealing with real-time feedback brings in issues of instrumentation and perceptional delays but are using the term here in the broad sense of "timely information."

mean systems that can sense anomalies in a process, determine the source of the issue, and automatically correct it without intervention. This allows businesses to not only reduce energy use, but also increase product quality and plant safety.

Parallel to the development of sensors and controls, large companies began to use corporate data networks to manage the business side of their operations. In the 2000s, these data networks evolved into enterprise resource planning (ERP) systems, continuing a trend of tracking and internalizing more and more information about their businesses. ERP systems are used by companies to integrate key decision making criteria across multiple aspects of a business, including accounting and finance, human resources, and supply chain management, and energy costs. In the last few years, ERP systems have begun to incorporate more detailed energy usage information, allowing corporate managers greater insight into a cost (and opportunity) that often gets overlooked.

Even more comprehensively, business management standards such as the ISO 9000 quality management standard began to take root in the 1990s, giving companies a rigorous method for tracking and improving product quality, safety, and environmental compliance in their own facilities and across supply chains. In 2011, the International Organization for Standardization (ISO) published ISO 50001, the first facility-level energy management standard. The emergence of energy tracking in enterprise resource planning systems will likely support the adoption of the ISO 50001 energy management standard, giving companies the systems and methods to both track energy performance and ensure continuous improvement in energy efficiency. This will eventually tie in with process systems inside the plant and supply chains outside the plant. "Intelligent" systems can help optimize the supply chain, bringing in raw materials on time and at the lowest cost, and organizing shipments to customers.

3. Service-Oriented Efficiency (Dematerialization).

Service-oriented efficiency covers structural changes in our economy that cause shifts from material goods or services toward digital solutions and services. This is often referred to as dematerialization because the substitution leads to less material use. We have already experienced many examples of this in our economy, such as telecommuting, e-commerce, and digital entertainment. A large body of literature exists on these topics, and energy savings varies depending on the area. Generally, substitution with digitally enabled goods and services leads to net improvements in energy efficiency over traditional methods. In some cases, however, significant uncertainty exists around the potential improvements when the substitution uses varying (and sometimes increasing) amounts of energy itself.

Scaling Up Intelligent Efficiency: the Network Effect

In addition to the three categories detailed above, there is another aspect of *intelligent efficiency* that is the key to realizing its potential: intelligent infrastructure. *Intelligent efficiency* enables more integrated, smarter, and more reliable infrastructure, such as smart power grids, cities, transportation systems, and communications networks. For example as buildings become increasingly networked and grid-connected, they play a crucial role in the development of "smart" cities that integrate resource management and information technology at the community level. As the types of *intelligent efficiency* become more integrated across our infrastructure, the potential savings become much greater than the sum of the individual parts, a concept we refer to as the "network effect."

In economics, the network effect occurs when the value of a good or service is dependent on the number of users of that good or service, i.e., consumers evaluate the attractiveness of a product based on whether others users in the same "network" have adopted the product (8, 9). Telephones and online social networks are classic examples of the network effect, because the more people using these products, the greater the benefits. Negative externalities can also emerge from the network effect, such as traffic congestion.

Many types of *intelligent efficiency* will benefit from the network effect. For example, smart phone "energy apps" could benefit from the network effect, as could car-sharing programs. Similarly, looking at a building or a plant as a system creates opportunities for co-optimization that exceed the sum of the savings from the optimization of the component systems. Many of these implementations of "intelligence" are not solely focused on energy, and they manage systems to optimize them for an array of benefits. IBM's project to bring city-wide control to Rio de Janeiro is a good example of the system enabling optimization of energy use in buildings (18). As we expand our system perspective, we expand our opportunities for greater network effect from *intelligent efficiency.*

Opportunities from a Shift to Systems-Based Efficiency

Future significant gains in energy efficiency require a move away from the focus on device-level efficiency and toward understanding how these devices interact to form systems, and then how systems can interact to form even more complex systems. Indeed, we already see that the focus on device-level efficiency is beginning to have diminishing returns. While it was an important initial approach, because higher efficiency requires intimate knowledge of the device design, the singular focus on devices has its limitations. As we push device efficiencies for a sustained period of time, we encounter technical and economic limits that mean that increases in energy savings become smaller and smaller. There is a growing awareness among the energy efficiency research and policy communities that the larger opportunity for energy efficiency lies in full system optimization. A great deal of the efficiency of a system lies not in the efficiency of the individual component devices, but rather arises from how devices interact and how the user interacts with the system overall.

A number of levels of systems exist, with opportunities for *intelligent efficiency* to benefit all:

- A process-level system such as a pump or heating system that includes devices such as motors, pumps, piping, boiler, heat exchangers, fans and controls
- A whole-building or manufacturing-plant system incorporating numerous process-level systems
- A large-scale, complex system, such as a transportation network, manufacturing supply chain, and a city with its infrastructure for transportation, buildings, services, etc.

Currently, we see most examples of *intelligent efficiency* emerging at the process level and whole-building or manufacturing-plant system level, and these are the focus of our case studies presented later in this report. At this point in time, the application of *intelligent efficiency* to large-scale systems remains largely conceptual, though the full report associated with this paper presents one case study that begins to address this level of system.

Motor-Driven Equipment as Systems.

In many process systems a large part of energy waste is due to the design, construction, installation, and operation of the entire system rather than inefficiency in any component device. This is especially evident in motor systems. Motor systems consume over half of the electricity produced in the United States (15). In 1992, the federal government defined minimum energy performance standards for electric motors, and raised the efficiency levels in 2007. These standards caused typical motors to increase their efficiency from 80-90% to 90-95%. While it is technically possible to still modestly increase motor efficiency the returns get smaller and smaller while the costs increase rapidly.

Motors are part of a system (Figure 2), and each element from electric supply to the actual use of the driven equipment represents opportunities for efficiency improvements. A shift in focus to the entire motor system can yield much higher savings at much lower cost. While savings from more efficient motors are usually 1-3%, savings from optimizing the system frequently exceed 20%. In fact, in some cases, installing even an efficient motor in the wrong application can actually increase energy use.

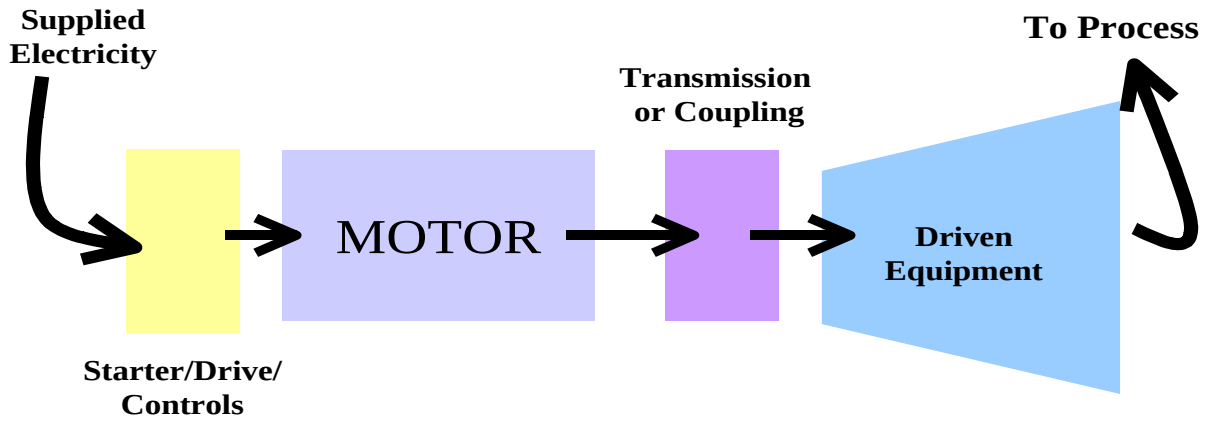

Figure 2: Elements of an Electric Motor System

Buildings as Systems.

There are times when optimizing each individual device does not lead to the best full-system design due to the complex interaction of devices within a system. In the heating, cooling, and ventilation systems in large buildings, for example, there are multiple zones (usually one room or office suite) each controlled by its own temperature sensor. These sensors tell a controller to change the amount of cooling and outdoor air provided to the space. However, this method of controlling each part of the system separately does not take into account the interaction among these various demands on system, which can actually increase energy use while reducing occupant comfort. As equipment is cycled to respond to coincident demands, it can easily overshoot target temperatures when adjacent areas call for heating and cooling concurrently. A more *intelligent* approach integrates the data gathered in each zone along with power consumed by the central chiller and distribution fans (6). This approach allows the system to deliver the required cooling and air quality to each zone while optimizing the system for energy efficiency.

Manufacturing Supply Chains as Systems.

The production of manufactured goods normally involves multiple facilities, some operating sequentially and other in parallel. These facilities are often owned by different companies producing feedstocks or components that are then used by other manufacturers to produce products that ultimately reach the consumer. These complex interactions lead to inefficiencies through both business transactions and logistics. For example, lack of coordination with a facility's suppliers or customers can result in long lead times for goods, and shipping those goods across the country (or the globe) takes considerable energy and can cause disruptions if something is delayed or damaged in shipment. Some thought leaders in the manufacturing sector are exploring how these multi-facility systems can be optimized for energy efficiency using information exchange, simulation, and feedback among the elements of the supply chain (19), and are exploring symbioses among the facilities, for example, ways they might share infrastructure and waste streams. An example of this has already been accomplished over the past three decades in Kalundborg Denmark (7).

THE BENEFITS OF INTELLIGENT EFFICIENCY

Intelligent efficiency is an enormously beneficial strategy for saving energy and maintaining a strong economy into a future constrained by scarce and uncertain resources. The benefits fall into categories: direct benefits from the avoidance of energy use due to greater efficiency; the non-energy benefits that stem from system optimization, including better services; and the economic benefits of more effectively using money that would otherwise go to energy bills.

Energy Savings

Recent long-term studies have suggested major energy savings potential in the U.S. from efficiency, on the order of 40-60% reductions in total energy use by 2050 (11). *Intelligent efficiency* is a critical tool in enabling this large savings potential. The benefits of energy savings from *intelligent efficiency* include reductions in energy bills for consumers and other "co-benefits" such as increased amenity (e.g., comfort, quality of life, productivity, product quality). And overall, energy efficiency has been shown to be among the lowest energy resource costs available in the marketplace (5). These consumption and demand reductions also offer the prospect of reducing future energy prices for all consumers by avoiding the need for future energy infrastructure investments (3).

Studies looking at information and communication technologies are very broad, and include both enabling technologies, such as high-speed Internet, and *intelligent efficiency* solutions, such as advanced manufacturing processes. Several studies examine the potential energy savings and policy recommendations for ICT-enabled energy efficiency. Two of the most comprehensive studies, which themselves contained extensive literature reviews, were a 2008 World Wildlife Fund (21) report and a 2009 ACEEE (10) report. These reports laid out both the potential savings with an array of policy considerations for achieving those savings.

These and other studies show the great potential for information and communication technologies, as well as other factors that enable *intelligent efficiency*. Just by taking advantage of the currently available technologies outlined in these studies, the United States could reduce its energy use by 12-22% and save tens if not hundreds of billions of dollars in energy savings and productivity gains. However, an *intelligent efficiency* approach will include even greater savings by using a wider array of new technologies and employing a system-wide optimization approach to maximize the savings. These individual saving will likely be amplified through the network effects discussed earlier. *Intelligent efficiency* could thus likely increase the total energy savings potential of the United States significantly beyond what is possible just through the enabling technologies listed above alone.

Economic Productivity and Jobs

The benefits of *intelligent efficiency* go far beyond energy savings. The expanded deployment of *intelligent efficiency* will also increase economic productivity and job creation. These economic benefits depend on how the money saved is ultimately spent. Money saved through energy efficiency moves consumer spending from the energy utility sector to other sectors of the economy that are much more labor intensive. For example, whereas $1 million spent on energy bills supports about ten jobs, if that money were spread throughout the economy it could support more than 17 jobs (1). Because savings from energy efficiency tend to last for a long time (often more than a decade) with new savings every year, the trend of increased jobs tends to be sustained. Because of this, jobs induced through energy efficiency tend to dwarf any changes in net jobs due to an initial investment.

Some applications of information and communication technologies may not appear to have the same benefits on direct job creation. When looked at through a narrow lens, productivity benefits that accompany information and communication technologies and *intelligent efficiency* may sometimes appear to lead to a decrease in the number of local jobs. But this accounting is mistaken. While it is sometimes the case that easier, technology-assisted access to information can lead to the elimination of certain jobs in some sectors of the economy, this access to information is often accompanied by greater overall economic activity, which leads to more jobs being created (12). Not only would rising productivity coincide with increased employment, but productivity would actually be a primary driver for the increased economic activity responsible for new employment. For example, one study shows that for every job directly lost, the Internet is responsible for creating 2.6 jobs (13).

CASE STUDIES OF INTELLIGENT EFFICIENCY

In order to make *intelligent efficiency* seem less abstract, we provide two case studies of how *intelligent efficiency* is emerging and is being implemented in the industrial sector at different system levels.

Smart Manufacturing Case Study: Moving to Closed-Loop Controls

The manufacturing sector reflects the evolving nature of intelligent efficiency. In many cases, a company will begin to incorporate information feedback and controls technologies to improve the operation of the system, and will continue to add more advanced technology in order to further reap the benefits of *intelligent efficiency*.

This progression can be seen in the steam system of Air Liquide. Air Liquide is a global corporation specializing in cryogenic liquids and industrial gases, and their Bayport plant is one of the largest industrial gas suppliers in the world, manufacturing oxygen, nitrogen, and hydrogen for use in other industries (16). Producing these gases requires a lot of steam heat, which is provided by seven large boilers (four of which are fired by the exhaust of gas turbines used to cogenerate electricity). Boiler operation is driven by several constraints, such as production volume, reliability, energy cost, and emissions. In order to track and optimize against these key indicators, Air Liquide has been using Visual MESA software to provide open-loop feedback to operators to guide them in optimizing their boiler systems. Using this method, operators receive data and analysis results every 15 minutes to take advantage of pricing changes in the electricity market, but typically only manually implement these results once or twice a shift. While this use of data tracking and analysis of operations is a best practice in the industry (and is an example of people-centered *intelligent efficiency*), Air Liquide took optimization to the next level by closing the loop between the data feedback system and the boiler control system. Instead of relying on operators to adjust the system a few times a day, the new system analyzes process variables and adjusts the system immediately, allowing it to update the boiler settings every 15 to 30 minutes.

Currently, the data feedback system in the open-loop optimization that Air Liquide had been using is becoming standard practice, and it takes about 10 to 12 months to install. Upgrading to closed-loop control can take another 6 to 12 months, but the energy savings alone are estimated to give the project a one-year payback. There are also additional sources of savings, such as increased system productivity and the benefits of freeing up operator time for other work.

Experts working on the project estimate that as more closed-loop systems are installed and all the savings are properly verified, more facilities will choose to install the data feedback systems with closed-loop control at the outset, bypassing open loop entirely. This would allow the entire installation to take about 12 months, and the simple payback based on total cost savings could drop to less than a year.

Smart Manufacturing Case Study: Plant-Wide Optimization

Manufacturing facilities are full of complex systems, and managing energy consumption requires not only understanding how these systems interact, but possessing real-time information about what the systems are doing at any given moment. Fortunately, smart sensing and control technology is improving this task. Automation companies have been exploring how new information technologies and advanced controls can improve system efficiencies and integrate controls across multiple systems. Both Schneider Electric™ and Rockwell Automation offer unique services to improve plant-wide optimization and significantly increase both energy efficiency and productivity.

Schneider Electric Company.

Schneider Electric's new Production Energy Optimization (PEO) concept includes a broad array of data sensors and allows extensive energy analytics to be run on various production indicators (20). The PEO system enables manufacturing and mining operations to track energy use per unit of product and to identify potential issues by comparing real-time data to a baseline. The PEO system also helps locate where in the process the problem occurred, so it can be fixed quickly.

One example of the PEO system can be seen at a new steel mill in Alabama, where Schneider Electric designed and installed sensors and variable-speed motors in each of the facility's 65 cranes. These sensors detect the load on the chain, along with any skew or sway the load is experiencing, and interact with the crane's motor to adjust the hoisting speed to the fastest safe speed while using the least amount of energy. A three-dimensional positioning system helps the crane operator guide the load to its destination. When the load gets close, the automated system takes over and adjusts the speed to reduce the sway. This process lets the load be lowered more quickly and has reduced the time for each trip by 15 to 20%.

Schneider Electric is currently implementing other aspects of Production Energy Optimization with a number of manufacturing and mining companies to help them identify, gather, and analyze energy usage and production data and optimize their time, costs, and energy savings. In many cases, these energy and production savings have made it possible for the system to pay for itself in just over a year.

Rockwell Automation.

Rockwell Automation has worked with an automaker to design a new facility which incorporates smart manufacturing technologies at every turn, enabling the company to accept custom orders from dealers and adapt—on the spot—to customers' preferences (17). Those same technologies will allow the company to track every auto part to its source, quickly identifying and addressing any quality or safety problems that may arise. The system predicts bottlenecks and breakdowns on the factory floor before they happen. It also has the capacity to seamlessly order parts from its suppliers the instant it receives a custom new car order from a dealer. The factory will minimize energy use, water use, and emissions while increasing economic performance, worker safety, and environmental sustainability. The reductions in oil and gas use and electricity use could be as great as 35% and 40%, respectively.

Barriers to Intelligent Efficiency

The benefits of *intelligent efficiency* are large; however, as with any new idea it faces numerous barriers to its full implementation in the marketplace. We group these barriers into three broad categories: social, financial, and structural. The social barriers reflect the lack of awareness of this new concept among consumers and people in the manufacturing, transportation, and buildings sectors, combined with inherent resistance to new and potentially risky ideas that are complex. Other social barriers include the learning curve with new technologies, the complexity of understanding the sometimes counter-intuitive systems approach, and the general risk aversion of end-users. Financial barriers encompass the upfront costs of implementing these new technologies, combined with the split-incentive problem that frequently bedevils other kinds of efficiency efforts. Whereas landlords of multi-family buildings or commercial office buildings bear the cost of installing new equipment, the tenants are often the ones who accrue the financial benefits of the energy savings. The landlords in this case have limited incentive to make energy efficiency upgrades. The structural barriers are also critical to dissolve. First, there is a lack of a skilled workforce to manage energy consumption in *intelligent efficiency* applications. Second, we have a shortage of data on measurable benefits of these applications. Third, there are important privacy issues to resolve. *Intelligent efficiency* systems in homes or businesses, such as smart meters with two-way communication, must be guaranteed not to allow open access to energy usage data.

POLICY RESPONSE TO BARRIERS TO INTELLIGENT EFFICIENCY

In response to these barriers, policy and policymakers can facilitate the deployment of systems built around intelligent efficiency in several key ways, by:

1. Expanding leadership by policymakers to educate their peers and the public, and for leaders in the public and private sectors to lead by example by implementing intelligent efficiency in their own operations.
2. Enhancing information infrastructure including making more detailed and timely energy data available, ensuring that the communications systems required to allow access to this information are in place for all consumers, and investing in the development of the human capital required for continued innovation.
3. Redefining regulatory business models under which public and private entities operate, in order to send a signal to markets to promote greater system efficiencies.

CONCLUSIONS

As we transition from a focus on component or device efficiency to a focus on optimizing energy-using systems, *intelligent efficiency* represents an important framework for creating the policies and programs necessary to achieve the large potential for energy efficiency promised by *intelligent efficiency*. While the term *intelligent* efficiency is new, the elements have been evolving in the marketplace for the past three decades and are now converging to create new opportunities.

As is common f new paradigms, *intelligent efficiency* promises to bring us essential benefits required by an economy that will thrive into the future and at the same time it faces various barriers. While some examples of *intelligent efficiency* have already been deployed in the United States, as the case studies presented in this report reflect, much more potential remains.

The promise of *intelligent efficiency* is great, offering a path to achieving the major, long-term energy reductions. The immediate opportunity is for increasing "intelligence" in the energy-using systems in our homes, buildings, farms, and factories. However, even greater opportunities exist through *integrated* and *crosscutting intelligent efficiency* in our infrastructure, such as smart cities, transportation networks, and power grids. This expanded vision for *intelligent efficiency* offers the potential to exponentially expand the benefits beyond the opportunities in individual systems. Future work will further identify and quantify the benefits of *intelligent efficiency* and will expand the range of policy responses that will enable *intelligent efficiency* to realize its full potential. With the groundwork laid for *intelligent efficiency* to spread throughout the economy in a resource-constrained future, our economy will have its best chance to grow and thrive.

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ISO 50001 versus Superior Energy Performance: Making Sense of Each for your Situation

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ABSTRACT

For years, utilities and governmental agencies industrial facility energy efficiency programs have been challenged by facility staff working around optimized equipment as well as completed measures not performing as planned, persisting as long as planned, or producing repeat projects. Strategic Energy Management (SEM) has been a growing response to these challenges, where the project approach to energy savings is replaced with a lasting facility energy management programs that produce business cultures that proactively drive projects, that make staff aware of the importance of energy efficiency, and that wraps all of this into an effort that corporate leaders can support. The most significant SEM developments of the last few years have centered in the ISO 50001 energy management system international standard as well as in the ISO-related, US Department of Energy-developed Superior Energy Performance (SEP) program.

For the past several years, EnerNOC, NRDC and SES have contributed to the creation of the ISO 50001 energy management system standard. In addition, our teams have worked with the SEP pilots, and have directly supported and interacted with industrial energy managers as they have applied these tools to their facilities.

This paper will provide a brief overview of what is common and distinct between ISO and SEP, including what elements are important to both facility and corporate energy managers. This paper will also put forth core information as well as essential usage guidelines for utility and government program managers who are considering leveraging ISO and SEP to support their efforts. Finally, this paper will suggest additional areas to further develop to ease ISO and SEP integration into programs and achieve maximum energy performance results.

INTRODUCTION

This paper presents ISO SEP, both designed to drive energy performance improvement and support energy program goals. ISO and SEP can be seen as tools that ultimately drive results, and the foundation of both is a systematic energy program approach, commonly described as SEM.

This paper begins by providing background on the core concepts within SEM and proceeds to lay out ISO and SEP along an SEM continuum. Next, the paper describes what ISO and SEP add incrementally to SEM, before describing the commonalities and distinctions of ISO and SEP. The paper then describes the elements that are important to facility and corporate energy managers as well as for utility and government program managers. The paper concludes with steps to ease integration of ISO and SEP to maximize energy performance.

STRATEGIC ENERGY MANAGEMENT (SEM) BACKGROUND AND CONTINUUM

Essentially, SEM is a system of organizational practices that increase the implementation of energy saving behaviors and projects. A relatively recent entry into the management systems space is energy. Although management system approaches have been applied to energy since at least the late 1980s, over the past ten years there has been increased emphasis by numerous groups such as the US Department of Energy Federal Energy Management Program's Resource Energy Manager (REM) Program, Puget Sound Energy's Resource Conservation Manager (RCM) Program, and the Northwest Energy Efficiency Alliance's (NEEA) Strategic Energy Management efforts. Common tenets of these efforts include organizational engagement, energy teams with action plans, executive commitment and involvement, and goal setting and tracking.

Large companies, mostly manufacturers, have implemented SEM on their own, typically as a way to unite their energy management efforts into consistent activities with common goals across multiple facilities. Over time these entities have developed robust reporting structures and technological tools and have demonstrated solid results that have been publicly reported to stakeholders. Some of these companies include Dow Chemical, Toyota North America, Nissan, Ford and Lyondell-Basell.

To better understand SEM, it can be placed along a continuum of energy program maturity.

Table 1. SEM Continuum

Level	Description
Individual SEM Elements	Some parts of SEM (e.g. an energy team)
Basic System	Executive commitment, an energy goal, and reporting to executives on progress towards that goal
Programmatic and Sustaining System	Elements combined in a way that energy program is more than based on an individual personality and sustains during absence or staff changes
Industry Standard System	Elements combine in fashion that meets an industry standard (e.g. ISO 50001)
Industry Standard System with Performance Component	Elements combined that meet industry standard and demonstrate performance improvement (e.g. Superior Energy Performance [SEP] Performance Pathway
World Class System	Best-in-class leader (e.g. "5 stars" on EnVINTA One-2-Five Assessment, or high scorer on SEP Mature Pathway)

A brief summary of the characteristics of the SEM continuum follows:

- **Individual SEM elements** are often deployed by organizations that have worked on energy projects for some time, and have taken steps to better organize their projects. These organizations still have not moved to a proactive approach to energy projects and typically react to outside forces when undertaking efforts.
- **Basic systems** combine elements including executive commitment to improve energy performance, an energy goal, and a group that reports to management on their progress towards that goal. NEEA labels this as the basic threshold of a system, deeming this to be the minimal level at which energy programs are considered strategic and sustaining.
- **Programmatic and Sustaining Systems** are those whose operation has transitioned from personality-based to a process-based, where the structure of the system guides action and not a single individual. An example of an observable behavior of such a system would be where an energy team still meets when their energy manager or energy team leader is not at work due to sickness. Another example of a programmatic and sustaining system would be where an energy team continues to function when there is a permanent staff change of the energy team leader or executive sponsor.
- **Industry Standard** energy management programs are those that meet a recognizable threshold, a level that the market understands and values. Until 2011, the only industry standard within the United States was the ANSI (American National Standards Institute) Management Systems for Energy (MSE) 2000:2008 standard; this standard did not see widespread adoption and recognition. In June 2011 the ISO 50001 Standard for Energy Management Systems was released and recognized by the US and other countries. The ANSI MSE 2000:2008 standard did include a requirement to improve energy performance overall, whereas ISO 50001 expects performance improvement without explicitly requiring improvement.
- **Industry Standard Systems with Performance Requirements** essentially add explicit energy performance improvement requirements above and beyond the expectations of regular industry standard systems. An organization at this level would meet or exceed a certain improvement level. The best example for this would be the Superior Energy Performance (SEP) Performance Pathway, where an organization meeting those requirements would combine ISO 50001 compliance with the attainment of a verifiable energy performance level (i.e. 5% for Silver, 10% for Gold, or 15% for Platinum, demonstrated over three years after the baseline period).
- **World Class Systems** are those that combine elements above and beyond the industry standard, and would typically be demonstrated by the top-tier of a given sector. Until 2011, the best examples of world class energy management systems were those who had consistently attained 5-Star ratings from the EnVINTA One-2-Five energy management assessment. Since the launch of the SEP program, a more recognizable example would be organizations that score highly on SEP's Mature Pathway.

WHAT ISO AND SEP INCREMENTALLY ADD TO SEM

From a high level, SEM components at the sub-ISO level are designed solely to support energy performance improvement. That is, as there is no recognizable standard to be certified to, there are minimal needs for management system components to enable verification and support auditing needs. An example of a performance supporting tool is an energy policy, where executives commit their organization to set goals and strategies, commit resources, and drive energy improvements. Other examples include energy team action plans, energy performance specifications within procurement policies, and energy team meeting minutes, all of which directly or indirectly impact energy performance.

ISO

As a management system standard, ISO 50001 is focused on energy performance improvement, with only the minimal amount of additional documentation required beyond those that are considered performance-related. Aligning the documentation required within ISO to that provided by NEEA on their www.EnergyImprovement.org website, roughly two-thirds of the ISO documents are seen as performance related, and the other third exist to support performance persistence via internal audits, corrective actions, documentation, and records control. This is an outcome of several countries, including the US, who wanted a performance-focused standard with only core documentation requirements.

One important concept is that of ISO compliance versus certification. Organizations which meet all of the ISO requirements can state that they are ISO-compliant, whereas organizations that are certified by a third party certification body (CB) can state that they are ISO-certified. External parties, such as customers within a supply chain, can place value on ISO certification as a way to ensure that their suppliers responsibly manage energy; the third party view can bring confidence to the supply chain. Other organizations may value the structure of the ISO standard and may seek to meet the requirements of compliance without seeking the external claims of being ISO certified. It is important to note that the former is not necessarily better than the latter, that is, certification is not necessarily better than compliance. Rather, the certification serves a purpose above and beyond compliance, namely, to add assurance of meeting the standard's requirements. An organization can go into the certification process because they have to, and may thus result in a half-hearted management system that simply "checks the boxes." Conversely, an organization may feel that the ISO requirements will benefit their management system and may subscribe to these for the "right reasons", resulting in a stronger management system than the previous example. The design of ISO 50001, complemented by professional ISO auditors, should result in similar high performance in either case, but when looking at an organization and the role of a standard in their performance, it is always vital to understand their motivation for using the standard.

SEP

SEP first requires organizations to meet the ISO standard, but then also meet an energy goal within a defined measurement and verification (M&V) protocol. These elements were based on gaps identified by the US Department of Energy (DOE), who also added and standards for personnel certification and system assessments to ensure confidence in goal attainment. Though initially funded by the DOE, the vision is that SEP will be run as an independent program that exists via certification and training fees, with DOE providing cost shares to launch the program until it is self-sustaining via an organization similar to the US Green Building Council and their administration of the Leadership in Energy Efficient Design (LEED) building program. The SEP requirements beyond ISO 50001 are established in the upcoming ANSI 50021 standard.

In addition to the certification process, with CBs that support ISO, SEP adds an energy performance verification component to support the reliability of results. The ANSI-American Society for Quality (ASQ) National Accreditation Board (ANAB) specially-accredits SEP verification bodies (VBs). These VBs employ specially-trained SEP Auditors and SEP Verifiers, separately credentialed individuals who ensure the management system and energy performance meet the SEP requirements. The SEP M&V protocol is established in the upcoming ANSI 50028 standard.

Similar to the ISO concepts of compliance versus certification are the SEP concepts of self-declaration versus certification. An organization can self-declare as an SEP Partner after having their SEP requirements documentation reviewed and approved by the SEP program administrator. Organizations that go the additional step of passing an onsite verification conducted by a VB are described as an SEP Certified Partner.

A key SEP concept is that subscribing organizations can choose one of two pathways to view their energy performance. These pathways were created so that both nascent and mature organizational energy programs can be accommodated and their performance improvements be recognized. SEP intends for most organizations to utilize the Energy Performance Pathway, which requires five (5), ten (10) or fifteen (15) percent improvement over three (3) years after a baseline period. Organizations with more established programs and long-term savings would utilize the Mature Pathway, which requires fifteen (15) percent improvement over ten (10) years after a baseline period, coupled with meeting minimum point requirements on the SEP Industrial Facility Best Practice Scorecard. These Mature Pathway organizations must meet energy performance improvement requirements but can gain additional points for going beyond the minimum threshold, and they also earn points for their management system being run at above-ISO levels. In either pathway, the baseline duration may be shortened if there is a lack of data, if the current management system was recently launched, or if there were significant operational changes in the last number of years.

The pathways and performance levels are illustrated in the following table.

Table 2. SEP Pathways and Performance Levels

Pathway	Description
Energy Performance	Energy performance improvements over 3 years after baseline period, as follows: • Silver level – 5% • Gold level – 10% • Platinum level – 15%
Mature	15% energy performance improvement over ten years after baseline period, with scorecard results as follows: • Silver Level – zero (0) additional energy performance points plus thirty (30) energy management best practice points • Gold level – ten (10) additional energy performance points plus forty (40) energy management best practice points • Platinum Level – twenty (20) additional energy performance points plus forty (40) energy management best practice points

COMMONALITIES AND DISTINCTIONS BETWEEN ISO AND SEP

While SEP is additive to ISO in terms of additional requirements and protocols, these result in important distinctions.

Table 3. ISO and SEP Elements

Elements	ISO	SEP
Energy Goal	Required	Required
Prescribed Energy Goal Number	Not prescribed	Prescribed
Energy Goal Methodology	Not prescribed	Prescribed
Energy Goal Attainment	Not required*	Required per the SEP M&V Protocol
Third party relations	Certification Bodies (CBs) who certify management system compliance; main role is the ISO Lead Auditor	Verification Bodies (VBs) who certify management system compliance and verify energy performance improvement; main roles are the SEP Lead Auditor and the SEP Performance Verifier
Surveillance between certification	Annual surveillance of ISO Certified organizations	Annual surveillance of SEP Certified Partners

* While not requiring organizations to actually improve, ISO 50001 does require that organizations attempt to improve, as demonstrated by documented actions within an Action Plan, recorded actions based on nonconformance to processes or goals, and other management system expectations.

The SEP M&V Protocol allows several different approaches to estimate energy performance improvements, such as forecasts, backcasts, standard conditions and chaining.

ELEMENTS IMPORTANT TO FACILITY AND CORPORATE ENERGY MANAGERS

When evaluating Strategic Energy Management or other programmatic approaches to energy, facility and corporate energy managers typically question the core value of energy as a driver of top-line and bottom-line performance. Beyond that, when evaluating ISO and SEP, facility and corporate energy managers typically ask themselves the following questions:

- Will certification help my customer base by opening new business or keeping markets open?
- Will compliance or certification increase performance above and beyond my existing energy management program?
- Will compliance result in an unsatisfactory amount of documentation?
- Will outside certification or verification drive additional performance or be considered unneeded overhead?

While those questions are best left to each organization to determine, there are additional considerations to evaluate when embarking on the path to compliance or certification within ISO or SEP.

One of the most important considerations when viewing either certification is the usage of baselines to demonstrate energy savings. ISO requires that the organization document how they established their baseline, essentially ensuring that the baseline and the baseline methodology are defensible. SEP mandates a specific set of baseline requirements. Organizations that subscribe to other baseline requirements, such as the use of a common year across multiple facilities, may have difficulty obtaining SEP certification. At best, their existing methodology would fit within the SEP requirements. At worst, their existing methodology would be outside of the SEP requirements and exceptions, thus requiring a separate baseline and likely different energy performance improvements.

ELEMENTS IMPORTANT TO UTILITY AND GOVERNMENT PROGRAM MANAGERS

As some utility and government programs have embraced SEM as a core strategy, they are expressing interest in ISO and SEP to understand how to leverage each. SEM is a facility-wide approach used in some advanced utility programs such as those in the Northwest (Energy Trust of Oregon, Bonneville Power Administration, Northwest Energy Efficiency Alliance), California (Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric) and the Midwest (Xcel Energy, Wisconsin Focus on Energy). Some of these programs have been resource-oriented, that is, quantifying and claiming energy savings that result from SEM using their own savings methodology and defined rigor.

The three year recertification of both ISO and SEP can be an opportunity for programs to incentivize their customers to maintain certifications. The recertification activity of ISO and SEP are effective ways to “lock-in” SEM and add confidence and reliability to the SEM approaches as well as the resulting energy savings. Program designers and evaluators could see ISO auditors and SEP verifiers as evaluators who potentially generate new projects. It is unclear if program designers and evaluators would see this as a free rider, that is, if their customers would have been recertified without the incentive. This question may be a very important one to answer.

Utility and government programs that drive discrete energy savings projects may value the annual surveillance of ISO certified organizations and SEP Certified Partners. Organizations who are being surveiled would need to identify new energy projects and/or may need to demonstrate that they are continually driving energy performance improvement.

There are differing opinions as to whether an ISO or SEP certified company would be eligible for utility incentives for savings projects, as to whether these are free riders. The authors opinion is that being ISO-certified does not require an organization to be efficient or to save, so the incentive can make many individual projects, or even the whole compliance activity, financially viable. We also believe that a continual improvement rate that maintains a higher percentage than is average for the industrial sector would not have happened without the incentive. For SEP, it is unclear as to whether the energy performance improvement requirement can mean that the organization is required to implement individual energy projects.

The SEP M&V protocol is flexible, offering a pathways with varying performance requirements and specifications for selecting shorter timeframes than those specified within the core requirements. One question for utility and government program

designers and evaluators is whether the monthly data expectations of SEP would meet their requirements to estimate energy performance improvements to count energy savings for a resource program. That is, the utility or government program would have to decide whether to require SEP certified organizations to increase the quantity of data beyond SEP to meet their program requirements. In addition, most utility programs use a forecast approach to demonstrate energy savings from a baseline, whereas SEP adds a "backcast" method. Program designers and evaluators would need to gain confidence in this method to ensure that it meets their expectations.

CONCLUSIONS

As the highest levels of SEM, both ISO and SEP bring unique value to the field of energy management and both should directly or indirectly influence organizations to drive greater results. Early adopter organizations in other countries have been certified to ISO and the US is beginning to see certifications to both ISO and SEP. In the coming years, as organizations go through the certification processes of ISO and SEP, they will provide feedback to the standards development community so that the standards themselves can be refined and guidance documentation can be created and expanded. The considerations identified in this paper should be accounted for, whether the organization is seeking to be certified or they are going to use a certification as part of their utility or governmental program. Key next steps include:

- **Utility and Government program managers should thoroughly review the ISO standard as well as the SEP documents:** Whether ISO and SEP are considered core program strategies or are simply considered influential to energy efficiency activities, program managers should understand both ISO and SEP. They should know the general concepts, the approaches, assumptions and methods to understand if these align to their view of energy savings.
- **Facility and Corporate Energy Managers should review the ISO standard as well as the SEP documents, based on their energy program direction:** At the basic level, energy managers can present elements of both standards to their executive leadership, using them as examples of what industry standard and world class energy programs can include. Both provide best practices for energy managers to embrace and adopt within their programs. Before thoroughly subscribing to either standard, energy managers should review each and ensure that the requirements and assumptions align to their organization's culture and vision.
- **Energy Management leaders should continue to refine the standards and develop guidance.** An emphasis should be placed on both increased performance as well as ease of use, so that greater numbers of organizations can benefit from these certifications. Organizations should be supported to integrate the certification requirements into their existing programs as well as into local utility and government programs to which they subscribe.

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