

Steam System Assessment Tool Application in the Chemical Industry

*Paul Nigro, Aaron Hart, and Michael J. Chimack,
University of Illinois at Chicago, Industrial Assessment Center
Christopher Heckert, Sargent & Lundy
Matthew D. Swanson, Elara Engineering*

ABSTRACT

This paper discusses the application of the U.S. Department of Energy's Steam System Analysis Tool (SSAT) at an industrial chemical plant focusing on the boiler and steam distribution systems. A total of seven recommendations were identified and analyzed using the software to determine the associated natural gas, electrical energy and water savings.

The total energy savings calculated using SSAT would reduce the energy budget of the plant by 7%. The natural gas usage of the plant would be reduced by 11%, while the electrical energy and city water usage would be reduced by 2% and 5%, respectively. These energy and resource conservation measures can be replicated by other chemical manufacturers in order to reduce their overall energy consumption.

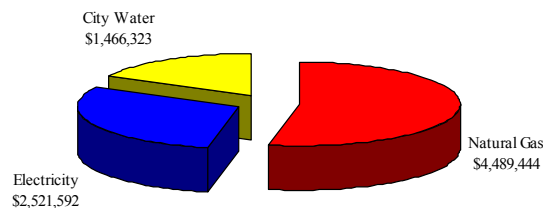
Plant Background

In August of 2005, the Industrial Assessment Center at the University of Illinois at Chicago performed an assessment of a chemical plant in northern Illinois. This plant, classified as an inorganic chemical plant, manufactures 81 million pounds of sodium and 91 million pounds of phosphate products annually. The utility usages for a one year period are shown below:

- Electrical Energy: 43,456,148 kWh
- Electrical Demand: 59,767 kW
- Natural Gas Purchased: 665,916 MMBtu
- Natural Gas Consumed: 648,918 MMBtu
- City Water: 490,238,308 gal

The total cost of natural gas, electricity and city water from May 2004 to April 2005 is over \$8.4 million. These costs are broken down in **Figure 1**.

Figure 1. Total Cost Breakdown



The energy and utility rates for this plant are as follows:

- Natural Gas Rate: \$6.50/MMBtu
- Electrical Energy Rate: \$0.0046/kWh
- Electrical Demand Rate: \$4.46/kW
- Bundled Electrical Rate: \$0.052/kWh
- City Water Rate: \$0.0038/gallon

Natural gas at this plant accounts for 53% of the total energy and utility budget, while electricity and city water account for 30% and 17%, respectively. Electricity is primarily used to support the compressed air, motor and lighting systems. Natural gas is primarily used for the boiler system and was the main focus of the assessment. The remainder of the natural gas consumed is used for chemical drying and hot water heating.

Boiler Description

The boiler system at this plant is composed of three boilers that generate steam for this plant and a neighboring plant. The main boiler, Boiler #1, is a watertube boiler that is rated at 123.9 MMBtu/hr and has a steam capacity of 100,000 lb/hr. The auxiliary boilers, Boiler #2 and Boiler #3, are also watertube boilers. They are rated at 52.6 MMBtu/hr and 38.8 MMBtu/hr, respectively. The boiler system operates 8,760 hr/year and consumed 494,064 MMBtu/yr of natural gas between May 2004 and April 2005. Since Boiler #1 produces 99% of the total steam generated at this plant, it is the only boiler considered in this analysis.

The steam production process for this boiler system begins with city water being pumped into a degasifier tank. After leaving the degasifier tank, the city water is regarded as makeup water and is pumped into the deaerator tank. Water entering the tank is treated with chemicals to maintain the appropriate level of hardness of the makeup water. The makeup water is then sent through an economizer and into the boiler through three 100 hp pumps.

Boiler #1 produces 225 psig saturated steam, a portion of which is exported to a neighboring plant. The producing plant does not use 225 psig steam, so the pressure of the steam to be used by this facility is reduced from 225 psig to 150 psig by a pressure reducing valve (PRV). This line is used for steam silos, heat exchangers and steam injection for the vacuum crystallizer system. On the same 225 psig pressure line, there also is a PRV that reduces the pressure to 15 psig. This line supplies steam to the steam heaters located throughout the plant.

Condensate is returned to the system through condensate return lines that feed into condensate return tanks. The system is composed of one main tank and several smaller tanks. One of the main issues of the boiler system at this plant is its condensate return system. The plant returns a low percentage of condensate from each of the pressure headers, which is a result of nonfunctioning condensate return tanks and condensate return lines that are in disrepair. The boiler system also contains a blowdown heat recovery system, but it was also in disrepair.

The plant uses three chemicals to treat the water in the boiler system. The first chemical is used to prevent scale buildup inside of the boiler. The second chemical is used in the deaerator tank to remove dissolved oxygen from the water. The last chemical is a filming amine that prevents corrosion, which is required by the steam users at the neighboring plant. The total annual chemical treatment cost for boiler makeup water is \$29,605/yr.

Although the boiler system is complex, the plant monitors and logs information daily, which was provided during the assessment. The data that is monitored and logged included mass flowrates, temperatures, excess O₂ percentages and boiler firing rates. The data provided by the plant is for the months of December 2004 through August 2005.

Using the average monthly mass flowrates, the blowdown mass flowrate, BD and blowdown factor, BF, are calculated using a conservation of mass equation around Boiler #1. The average mass flowrate of blowdown is 2,774 lb/hr and the blowdown factor is 5.5%.

This plant also monitored and logged mass flowrates throughout the system for the months of September 2004 through August 2005. The average mass flowrate of Boiler #1 steam production is 47,055 lb/hr and the average mass flowrate of steam provided to neighboring plant is 17,151 lb/hr. In order to determine the average mass flowrate of steam for the remaining medium-pressure line, the low-pressure line and deaerator steam injection, the data shown above is used.

The average mass flowrates of steam for the space heating equipment on the low-pressure line is calculated through the use of bin data from the heating months and is determined to be 4,605 lb/hr. The remaining steam is used in the medium-pressure line and deaerator steam injection. These average mass flowrates are calculated in the Boiler Analysis section of this report.

Although the Industrial Assessment Center received sufficient data from the plant, most of the proposed recommendations required iterative methods of computation. It is for this reason that the Steam System Assessment Tool (SSAT) is used to model the steam system.

SSAT Description

The Steam System Assessment Tool is a free Microsoft Excel[®] based program developed by KBC Linnhoff March and Spirax Sarco, Inc. for the U.S. Department of Energy that provides its user with the capability of creating an approximate model of a boiler system. This model can then be used to determine energy usage and emission reductions as well as cost savings resulting from the entry of projects. These projects are steam system improvements that can be performed on an existing boiler system. The overall functionality of the program is user friendly, provided that the user has knowledge of the operation of the boiler and steam distribution systems. This knowledge involves the ability to determine temperatures, pressures, mass flowrates, efficiencies, operating costs, etc., throughout the system. If a user is unable to determine a required input, the program does supply default options that can be chosen.

After loading the program, the user is given the option of selecting the number of headers in the boiler system that will be modeled. It should be noted that SSAT can only model systems that contain three headers or less. Another limitation of the software is that it can only simulate a boiler system that contains one boiler. This causes the exclusion of boiler loading effects on each of the projects provided in the software. If multiple boilers do exist in the system, the impact boiler should be modeled. The impact boiler is considered to be the boiler that compensates for any instantaneous changes to the steam demand of the plant. The user is then presented with seven tabs, which include Input, Stack Losses, Model, Projects Input, Projects Model, Results and User Calculation. Modeling begins with the Quick Start Input Tab, shown in Figure 2.

Figure 2. Quick Start Tab

Steam System Assessment Tool		
3 Header Model		
Data Entry Form for Current System		
The data entry form is split into two sections. "Quick Start" enables you to enter a minimum amount of information about your site and to start modeling your system right away. "Site Detail" allows you to provide more detailed information about your site to improve the accuracy of the model.		
Yellow shaded cells require user input.		
Where different options can be chosen by the user, the required supplementary data input cells are shaded green and are indicated by red arrows.		
Quick Start		
Enter Case Description		SSAT Default 3 Header Model
General Site Data	Input Data	Notes/Warnings
Site Power Import (+ for import, - for export)	0 kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0480 \$/kWh	Typical 2003 value: \$0.05/kWh
Operating hours per year	8760 hrs	
Site Make-Up Water Cost	0.0045 \$/gallon	Typical 2003 value: \$0.0025/gallon
Make-Up Water Temperature	90 F	
Note: Enter average values for the operating period being modeled		
Boiler fuel - Choose from this drop-down list		Natural Gas
Site Fuel Cost per 1000 s cu ft	6.50 \$	Typical 2003 value: \$5.78/(1,000 s cu ft)
Note: Fuel HHV is 1,000 Btu per s cu ft (23,311 Btu/lb)		
Note: Emissions cannot be calculated for user defined fuels		
Steam Distribution	Input Data	Warnings
High Pressure (HP)	225 psig	
Medium Pressure (MP)	150 psig	
Low Pressure (LP)	15 psig	
HP Steam Use by Processes	17.151 kibh	
MP Steam Use by Processes	19.3 kibh	
LP Steam Use by Processes	4.605 kibh	
Note: Enter process steam use at each pressure level. Excludes turbines, letdowns, leaks, trap losses, deaeration steam and vents		
Steam Turbines		
Do you have a steam turbine installed between HP and LP?	No	
Do you have a steam turbine installed between HP and MP?	No	
Do you have a steam turbine installed between MP and LP?	No	
Do you have an HP to condensing turbine installed?	No	
For a Condensing Turbine, please define how the turbine operates and then provide supplementary information below:		
Mode of operation	Not installed	
Option 1 - Fixed power generation	1000 kW	
Option 2 - Fixed steam flow	50 kibh	
Steam Traps	Input Data	Warnings
Number of traps at each pressure level		
Traps on HP header	150 traps	
Traps on MP header	150 traps	
Traps on LP header	150 traps	
Select the approximate timing of your last trap testing and maintenance program		9-10 years ago
The information you have entered above will allow you to start using the model. A closer match to your actual site operation can be obtained using the "Site Detail" options below.		

This is where the user begins by entering all the information that is required to create an initial boiler model. This information includes general site data, boiler fuel type and cost, header pressures and flowrates, presence of turbines and number of steam traps in the system. The user is also required to input when the last steam trap maintenance program was performed.

The software only considers average values in its calculations. If the user of the software has daily flowrates and temperature readings of the boiler system, average values should be calculated and entered into the model. If some values are unknown, SSAT offers default options for most entries.

After the information is entered, the system can be modeled more accurately through the use of the Site Detail section in the Input Tab. These details include specific boiler data such as boiler efficiency, blowdown rate and quality of the steam, as shown in Figure 3. If the efficiency of the boiler is unknown, SSAT assumes a percentage based on the type of fuel used.

Figure 3. Boiler Data Section

Site Detail		
Boiler		
Method for specifying boiler efficiency Option 2 - Enter user-defined value		
<small>Note: Model default efficiencies represent Best Practice values assuming good operation and the installation of an economizer</small>		
Option 2 - Enter efficiency (%)	84.9 %	
<small>Note: Boiler efficiency is defined as 100% - Stack Loss (%) - Shell Loss (%). The "Stack Loss" sheet gives more information on heat losses</small>		
<small>Note: Efficiency is based on Higher Heating Value. Economizers are included in the boiler efficiency. Boiler blowdown losses are excluded</small>		
Blowdown Rate (% of feedwater flow)	5.5 %	
Do you have blowdown flash steam recovery to the LP system? No		
<small>Please select how you wish to define your HP generation condition and then provide supplementary information below if required:</small>		
Method for specifying HP generation condition Option 3 - User-defined saturated conditions		
<small>Note: As a default, the model will use HP steam with 100 F of superheat. At HP pressure (225 psig), this corresponds to a temperature of 407 F</small>		
Option 2 - Enter temperature	600 F	
Option 3 - Enter thermodynamic quality	100 % dry	
<small>Note: Saturation temperature at specified HP pressure (225 psig) is 397 F</small>		
<small>Note: Steam quality is an expression of the percentage dryness (or vapor fraction) of the steam</small>		

The required efficiency is the thermal efficiency of the boiler, which includes stack losses and shell losses. The Stack Losses Tab includes required entries regarding boiler stack data. These include stack gas temperature, ambient temperature and stack gas oxygen content. The Stack Losses Tab illustrates stack losses as a function of stack oxygen and temperature. This utility is available for various fuels. When the boiler system contains an economizer, the stack gas temperature after the economizer can be entered to calculate losses to determine the combustion efficiency. Once the stack loss percentage is obtained, shell losses are added to determine the thermal efficiency of the boiler. SSAT suggests shell losses of less than one percent for boilers operating at full load and between one and two percent for boilers operating at a reduced load. The resulting thermal efficiency is then entered in the Input Tab.

Steam turbines are another component of steam systems that can be simulated by entering operating details in the Input Tab. These details include isentropic efficiency of the turbines and their mode of operation. The operation mode can be set so that the turbine balances the header that is at a lower pressure, at a fixed operation, or between a range of pressures. The fixed and range operations can be regulated by a steam flowrate or power generation criteria. The High-Pressure to Low-Pressure Steam Turbine section is shown in Figure 4.

Figure 4. Steam Turbine Section

In the Quick Start section, you specified that no HP to LP turbine(s) were installed - Please move on to the next section		
HP to LP Steam Turbine(s)	Input Data	Notes/Warnings
Isentropic efficiency	85 %	
<small>Note: If multiple turbines are installed, the operation of the impact turbine (the turbine affected by changes to the system) should be modeled</small>		
<small>Note: A generator electrical efficiency of 100% is assumed by the model</small>		
Select the appropriate turbine operating mode Option 1 - Balances LP header (Model default option)		
<small>Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand</small>		
Option 2 - How should the fixed turbine operation be defined? Option 2 not selected		
Option 2 - Fixed steam flow	100 kb/h	
Option 2 - Fixed power generation	2000 kW	
Option 3 - How do you wish to define the operating range? Option 3 not selected		
Option 3 - Minimum steam flow	50 kb/h	
Option 3 - Maximum steam flow	150 kb/h	
Option 3 - Minimum power generation	1500 kW	
Option 3 - Maximum power generation	2500 kW	

If a condensing steam turbine is being simulated, the condenser pressure and the isentropic efficiency are required. Control temperatures can also be entered if cooling water is used through a PRV.

System components such as a deaerator tank, feedwater heat recovery system and a condensate return system can also be modeled, as shown in Figure 5.

Figure 5. Boiler Systems

Deaerator		Input Data	Warnings
Vent (as % of boiler feedwater flow)		0.247 %	
Note: Values of around 0.1% are typical			
Select the appropriate deaerator operating mode			Option 2 - User-defined pressure
Option 2 - Specify pressure		4.5 psig	
Note: Deaerator uses LP steam. Specified LP pressure is 15 psig			
Feedwater Heat Recovery System			
Heat recovery exchanger on the condensate tank vent?			No
If yes, enter approach temperature			20 F
Note: Approach temperature is defined as the minimum allowable temperature difference in the heat exchanger			
Heat recovery exchanger on boiler blowdown?			No
If yes, enter approach temperature			20 F
Process Condensate		Input Data	Warnings
Condensate return temperature to tank			130 F
HP condensate recovery			0 %
MP condensate recovery			5 %
LP condensate recovery			5 %
Note: Condensate recovery specified as the percentage of steam supplied to the processes at each level			
Do you flash condensate to MP steam?			No
Do you flash condensate to LP steam?			No

In the Deaerator section, the user can input the deaerator operating pressure and the venting percentage. For these two entries, SSAT provides the user with typical values. If a feedwater heat recovery system is present, approach temperatures should be entered. An approach temperature is defined as the temperature difference between the hot side outlet and the cold side inlet of the heat exchanger. Data can also be entered for a condensate return system. This data includes condensate return temperature, percentage of condensate returning to the condensate tank and the presence of flashing condensate. The boiler system that is modeled must have a condensate tank and the condensate return temperature must be below saturated temperature at atmospheric pressure.

The model can be improved further by taking into consideration heat losses from the system. These include losses from steam traps, steam leaks and insulation losses, as shown in Figure 6.

Figure 6. Heat Losses

Steam Trap Losses and Steam Leaks			
Choose a method for estimating steam losses			Option 2 - Losses calculated from user-defined data
Option 2 - Specify number of failed traps at each pressure level			Warnings
Trap failures on HP header		0 traps	
Trap failures on MP header		0 traps	
Trap failures on LP header		0 traps	
Option 2 - Specify number of steam leaks at each pressure level			Warnings
Steam leaks on HP header		0 leaks	
Steam leaks on MP header		0 leaks	
Steam leaks on LP header		0 leaks	
Note: Calculated values for current loss and leak rates based on current user inputs are:- HP header - Trap failures: 0, Loss per trap 0.022 kbb/h - Total trap loss = 0.00 kbb/h. Steam leaks: 0, Loss per leak 0.005 kbb/h - Total leaks = 0.00 kbb/h. MP header - Trap failures: 0, Loss per trap 0.038 kbb/h - Total trap loss = 0.00 kbb/h. Steam leaks: 0, Loss per leak 0.010 kbb/h - Total leaks = 0.00 kbb/h. LP header - Trap failures: 0, Loss per trap 0.005 kbb/h - Total trap loss = 0.00 kbb/h. Steam leaks: 0, Loss per leak 0.001 kbb/h - Total leaks = 0.00 kbb/h.			
Insulation Heat Losses		Input Data	Notes/Warnings
Choose a method for specifying heat losses			Option 1 - Specify fixed heat loss
Option 1 - Heat loss on HP header		0 MMBtu/h	
Option 1 - Heat loss on MP header		0 MMBtu/h	
Option 1 - Heat loss on LP header		0 MMBtu/h	
Option 2 - % of heat lost on HP header		0.1 %	
Option 2 - % of heat lost on MP header		0.1 %	
Option 2 - % of heat lost on LP header		0.1 %	
Note: Losses calculated as the percentage of heat flow entering each header Note: Current values for heat entering headers are: HP 57 MMBtu/h, MP 36 MMBtu/h, LP 13 MMBtu/h - These may change when the model is updated			

The heat losses from failed open steam traps and steam leaks can be manually entered or calculated by SSAT. If the number of steam trap failures is unknown, SSAT can approximate the percentage of failed steam traps based on the last time a steam trap maintenance program was performed. Heat loss through steam traps is computed in SSAT by assuming a one-eighth of an inch steam leak is present in the failed steam traps (Steam Specialist Qualification Training). The percentages of steam trap failures based on the last maintenance program are shown in Table 1.

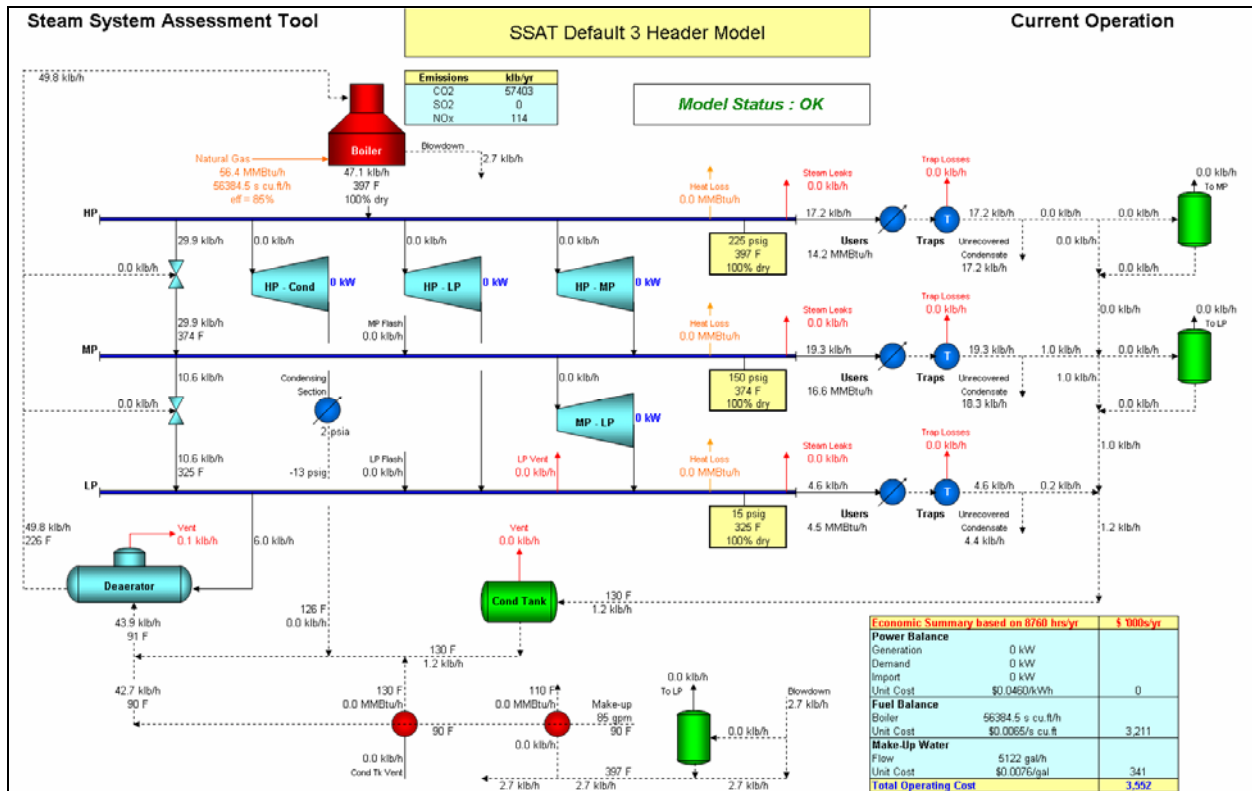
Table 1. Percentage of Steam Trap Failures

Steam Trap Model Basis	
Test Timing	Steam Traps Failed [% of Traps]
< than 1 year	3
1-2 years ago	5
3-5 years ago	10
6-8 years ago	15
9-10 years ago	30

Source: Steam Specialist Qualification Training

Heat loss through steam leaks in the steam pipelines is computed in a similar manner, assuming a steam leak diameter of one-sixteenth of an inch (Steam Specialist Qualification Training). Heat losses from insulation can be entered based on a fixed heat loss rate (MMBtu/hr) or as a percentage of heat loss from each header. After completing this tab, a boiler model is generated, as shown in Figure 7.

Figure 7. Boiler Model Tab



The figure above displays the modeled boiler system with the following equipment: a boiler, three pressure headers, deaerator tank, condensate tank, PRVs, turbines, flash tanks and steam traps.

Included in the model are the flowrates, temperatures, pressures and power generation computed from the user inputs. This tab is particularly useful because it allows the user to visually compare the SSAT boiler model to the actual boiler system. It should be noted that SSAT does not allow the user to modify the equipment in the Model Tab. If a boiler system does not have a deaerator tank, SSAT cannot be used to analyze the system. In some cases a model can be created that accounts for differences in the real boiler system and the model boiler system. The data in the Input Tab can then be modified to increase the accuracy of the model.

The most difficult aspect of creating the model involves entering the steam mass flowrates and the percentages of condensate return in the Input Tab. If any of these values are unknown, trial and error methods are required to determine the unknown values. If the makeup water mass flowrate is known, the unknown values can be modified until the makeup water mass flowrate is attained in the model. It is difficult because the process differs for each boiler system that is modeled. Upon completion of the model, projects can be entered to reduce energy usage and emissions, which result in cost savings.

The projects that are provided in the software are modified in the Projects Input Tab. These projects include:

- Change Process Steam Requirements
- Use an Alternative Fuel
- Change Boiler Efficiency
- Change Boiler Blowdown Rate
- Blowdown Flash to Low-Pressure
- Change Steam Generation Conditions
- Install Steam Turbines
- Install Feedwater Heat Recovery Exchanger Using Condensate Tank Vent
- Feedwater Heat Recovery Exchanger Using Boiler Blowdown
- Condensate Recovery
- Install Condensate Flash
- Steam Trap Losses
- Steam Leaks
- Improved Insulation

After data is inputted into one of the projects, the resulting changes in the boiler system are shown in a Project Model Tab similar to that in Figure 7. The results from implementing the project are shown in Figure 8.

Figure 8. Results Tab

Steam System Assessment Tool										
3 Header Model										
Results Summary										
SSAT Default 3 Header Model										
Model Status : OK										
Cost Summary (\$ '000s/yr)		Current Operation	After Projects	Reduction						
Power Cost		0	0	0 N/A						
Fuel Cost		3,211	3,151	60 1.9%						
Make-Up Water Cost		202	98	104 51.5%						
Total Cost (in \$ '000s/yr)		3,412	3,249	164 4.8%						
On-Site Emissions		Current Operation	After Projects	Reduction						
CO2 Emissions		57403 kbi/yr	56331 kbi/yr	1072 kbi/yr 1.9%						
SOx Emissions		0 kbi/yr	0 kbi/yr	0 kbi/yr N/A						
NOx Emissions		114 kbi/yr	112 kbi/yr	2 kbi/yr 1.9%						
Power Station Emissions		Reduction After Projects	Total Reduction							
CO2 Emissions		0 kbi/yr	1072 kbi/yr	-						
SOx Emissions		0 kbi/yr	0 kbi/yr	-						
NOx Emissions		0 kbi/yr	2 kbi/yr	-						
<small>Note: Calculates the impact of the change in site power input on emissions from an external power station. Total reduction values are for site + power station</small>										
Utility Balance		Current Operation	After Projects	Reduction						
Power Generation		0 kW	0 kW	-						
Power Import		0 kW	0 kW	0 kW N/A						
Total Site Electrical Demand		0 kW	0 kW	-						
Boiler Duty		56.4 MMBtu/h	55.3 MMBtu/h	1.1 MMBtu/h 1.9%						
Fuel Type		Natural Gas	Natural Gas	-						
Fuel Consumption		56384.5 scf/h	55331.6 scf/h	-						
Boiler Steam Flow		47.1 kib/h	46.2 kib/h	0.9 kib/h 1.9%						
Fuel Cost (in \$MMBtu)		6.50	6.50	-						
Power Cost (as \$MMBtu)		13.48	13.48	-						
Make-Up Water Flow		5122 gal/h	2485 gal/h	2636 gal/h 51.5%						
Turbine Performance		Current Operation	After Projects	Marginal Steam Costs						
HP to LP steam rate		Not in use	Not in use	(based on current operation) HP (\$/kbt) 9.51						
HP to MP steam rate		Not in use	Not in use	MP (\$/kbt) 9.47						
MP to LP steam rate		Not in use	Not in use	LP (\$/kbt) 9.47						
HP to Condensing steam rate		Not in use	Not in use							
<table border="1"> <thead> <tr> <th colspan="2">List of Selected Projects</th> </tr> </thead> <tbody> <tr> <td colspan="2">Increase MP condensate recovery</td> </tr> <tr> <td colspan="2">Increase LP condensate recovery</td> </tr> </tbody> </table>					List of Selected Projects		Increase MP condensate recovery		Increase LP condensate recovery	
List of Selected Projects										
Increase MP condensate recovery										
Increase LP condensate recovery										
Gas Turbine Assessment										
Your site power demand is likely to be too small for the economic installation of a gas turbine + waste heat boiler										
Warnings - Any warnings listed below may impact on the validity of the simulation										
Current Operation		After Projects								

The Results Tab above represents a Condensate Recovery Project that will be presented in the Recommendations section. This tab illustrates the current and proposed operation of the model, reductions in energy and emissions, as well as associated cost savings. It also includes the marginal steam cost for each of the pressure headers. The marginal steam cost is composed of the cost of natural gas, makeup water and electricity associated with the modeled boiler system. The marginal steam cost for each of the pressure headers changes for each project that is entered. This allows the user to calculate savings using the marginal steam cost. This feature can also be beneficial to a plant that is selling steam to a neighboring plant, such as the plant detailed in this report. It allows the plant to accurately charge the neighboring plant for steam on a one thousand pound basis.

Another feature of SSAT is its ability to identify errors in user inputs. If the user enters a value that is not probable, SSAT displays a warning in the Input Tab to notify the user of the incorrect input. SSAT also displays warnings in the Results Tab to notify the user of potential problems that are in the system after inputting a project. This warning feature is beneficial because it notifies the user of errors that could ultimately affect the accuracy of the model.

The final tab included in SSAT is the User Calculation Tab. This tab is a basic Microsoft Excel® worksheet that can be used in making calculations without having to open a new file. It also allows the user the capability of selecting values from any of the proceeding tabs for calculation purposes.

SSAT has the capability of modeling several projects at the same time. Since most projects will interact with each other, as discussed in the Interactive Effects section, this feature

can be beneficial in determining the total savings resulting from multiple projects. It also allows plant personnel to justify the installation of one or more projects that fall within the plant's investment guidelines.

The U.S Department of Energy also offers training on the use of SSAT. The training consists of a 2-1/2 day course, which includes an exam to earn a Steam System Specialist Qualification title. The classroom portion of the training is 16 hours of formal training in the use of BestPractices Steam Tools, which includes SSAT. Information on this training, which is offered for a nominal fee, can be found at http://www1.eere.energy.gov/industry/bestpractices/steam_systems.html. A free version of the software can be downloaded at the DOE Best Practices website at <http://www1.eere.energy.gov/industry/bestpractices/software.html>.

Boiler Analysis

The boiler system at this plant is an ideal candidate for SSAT modeling for several reasons. It contains one boiler that produces 99% of total steam generated for three different pressure lines and one deaerator tank. Although the boiler system contains several condensate return tanks, they can be modeled as one tank with an average return temperature, which is below saturated temperature at atmospheric pressure. In addition to physical characteristics of the boiler system, the mass flowrates, temperatures, excess O₂ percentages and boiler firing rates are logged and were provided by plant management. This information was used to check the model accuracy by comparing it with the real boiler system.

SSAT modeling of this boiler system began by selecting a three pressure line setup for the 225 psig, 150 psig and 15 psig lines. General site data was entered next in the Input Tab, as shown in Figure 9.

Figure 9. Input Tab

Steam System Assessment Tool		
3 Header Model		
Data Entry Form for Current System		
The data entry form is split into two sections. "Quick Start" enables you to enter a minimum amount of information about your site and to start modeling your system right away. "Site Detail" allows you to provide more detailed information about your site to improve the accuracy of the model.		
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Enter Case Description	SSAT Default 3 Header Model	
General Site Data	Input Data	Notes/Warnings
Site Power Import (+ for import, - for export)	0 kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0460 \$/kWh	Typical 2003 value: \$0.05/kWh
Operating hours per year	8760 hrs	
Site Make-Up Water Cost	0.0076 \$/gallon	Typical 2003 value: \$0.0025/gallon
Make-Up Water Temperature	90 F	
<small>Note: Enter average values for the operating period being modeled</small>		
Boiler fuel - Choose from this drop-down list		Natural Gas
Site Fuel Cost per 1000 s.cu.ft	6.50 \$	Typical 2003 value: \$5.78/(1,000 s.cu.ft)
<small>Note: Fuel HHV is 1,000.Btu per s.cu.ft (23,311.Btu/lb)</small>		
<small>Note: Emissions cannot be calculated for user defined fuels</small>		

There is a section in the tab to input power generated by the boiler system. This facility's boiler system does not import or export any power so the Site Power Import Tab is set to zero kW. The site power cost is the electrical energy rate of the plant. This plant is also charged for electrical demand so the bundled electrical rate of \$0.052/kWh is used. The makeup water and natural gas rates of \$0.0076/gallon and \$6.50/MMBtu are also entered. The makeup water rate of \$0.0076/gallon includes chemical costs and will be calculated later in this section. The total

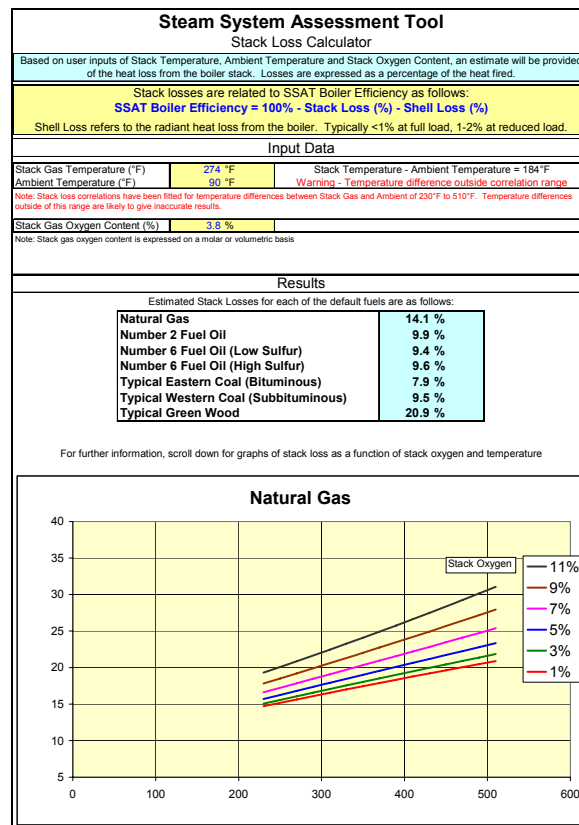
annual operating hours of 8,760 hr/yr and the makeup water temperature of 90°F are then entered.

Data is not required in the Steam Turbine section because this system does not contain steam turbines. For the Steam Trap section, the total number of steam traps on each steam line is conservatively estimated to be 150 traps.

After the above data is entered, the thermal efficiency of the boiler is determined through the use of the Stack Losses Tab, shown in Figure 10. Although there is not an option to indicate whether the boiler system utilizes an economizer, the system can be modeled as if it has one. Using the stack temperature after the economizer takes into account the energy efficiency associated with an economizer. The average stack temperature of 274°F, which is recorded after the economizer outlet, is entered into the stack gas temperature input. The ambient temperature of 90°F and the average stack gas oxygen content of 3.8% are the other required inputs.

Using the input data, SSAT automatically calculates the associated stack losses of Boiler #1. The efficiency of Boiler #1 is the net result of average losses from the boiler stack and boiler shell. The calculated thermal efficiency of Boiler #1 is 84.9%.

Figure 10. Stack Losses



The accuracy of the model can be increased through the Site Detail section in the Input Tab as shown in Figure 11.

Figure 11. Site Details Section

Site Detail		
Boiler		
Method for specifying boiler efficiency Option 2 - Enter user-defined value		
<small>Note: Model default efficiencies represent Best Practice values assuming good operation and the installation of an economizer</small>		
Option 2 - Enter efficiency (%)	84.9 %	
<small>Note: Boiler efficiency is defined as 100% - Stack Loss (%) - Shell Loss (%) The "Stack Loss" sheet gives more information on heat losses</small>		
<small>Note: Efficiency is based on Higher Heating Value. Economizers are included in the boiler efficiency. Boiler blowdown losses are excluded</small>		
Blowdown Rate (% of feedwater flow)	5.5 %	
Do you have blowdown flash steam recovery to the LP system? No		
Please select how you wish to define your HP generation condition and then provide supplementary information below if required:		
Method for specifying HP generation condition Option 3 - User-defined saturated conditions		
<small>Note: As a default, the model will use HP steam with 100 F of superheat. At HP pressure (225 psig), this corresponds to a temperature of 497 F</small>		
Option 3 - Enter temperature		
Option 3 - Enter thermodynamic quality	100 % dry	
<small>Note: Saturation temperature at specified HP pressure (225 psig) is 397 F</small>		
<small>Note: Steam quality is an expression of the percentage dryness (or vapor fraction) of the steam</small>		

The thermal efficiency of 84.9% is automatically populated in the Site Detail Tab and the blowdown rate of 5.5% from Equation (2) is entered. The high-pressure line is estimated to have a thermodynamic quality of 100%.

Additional data is entered in the Deaerator and Feedwater Heat Recovery System sections, as shown in Figure 12.

Figure 12. Site Details Section

Deaerator	Input Data	Warnings
Vent (as % of boiler feedwater flow)	0.247 %	
<small>Note: Values of around 0.1% are typical</small>		
Select the appropriate deaerator operating mode Option 2 - User-defined pressure		
Option 2 - Specify pressure	4.5 psig	
<small>Note: Deaerator uses LP steam. Specified LP pressure is 15 psig</small>		
Feedwater Heat Recovery System		
Heat recovery exchanger on the condensate tank vent? No		
<small>Note: Approach temperature is defined as the minimum allowable temperature difference in the heat exchanger</small>		
Heat recovery exchanger on boiler blowdown? No		

The percentage of vent mass flow, with respect to the boiler feedwater flow, is determined to be 0.247 based on data collected on the assessment and the data supplied by the plant. The deaerator pressure of 4.5 psig is also entered. Although the boiler system contained a blowdown heat recovery system, the system is not in operation and is not considered for the model.

The heat losses associated with failed steam traps, steam leaks and poor insulation are now entered in the sections shown in Figure 13.

Figure 13. Site Details Section

Steam Trap Losses and Steam Leaks		
Choose a method for estimating steam losses Option 2 - Losses calculated from user-defined data		
Option 2 - Specify number of failed traps at each pressure level Warnings		
Trap failures on HP header	0 traps	
Trap failures on MP header	0 traps	
Trap failures on LP header	0 traps	
Option 2 - Specify number of steam leaks at each pressure level Warnings		
Steam leaks on HP header	0 leaks	
Steam leaks on MP header	0 leaks	
Steam leaks on LP header	0 leaks	
<small>Note: Calculated values for current loss and leak rates based on current user inputs are:-</small>		
<small>HP header - Trap failures: 0, Loss per trap 0.022 kbt/h - Total trap loss = 0.00 kbt/h. Steam leaks: 0, Loss per leak 0.005 kbt/h - Total leaks = 0.00 kbt/h.</small>		
<small>MP header - Trap failures: 0, Loss per trap 0.038 kbt/h - Total trap loss = 0.00 kbt/h. Steam leaks: 0, Loss per leak 0.010 kbt/h - Total leaks = 0.00 kbt/h.</small>		
<small>LP header - Trap failures: 0, Loss per trap 0.005 kbt/h - Total trap loss = 0.00 kbt/h. Steam leaks: 0, Loss per leak 0.001 kbt/h - Total leaks = 0.00 kbt/h.</small>		
Insulation Heat Losses		
Choose a method for specifying heat losses Option 1 - Specify fixed heat loss		
Option 1 - Heat loss on HP header Notes/Warnings		
Option 1 - Heat loss on MP header	0 MMBtu/h	
Option 1 - Heat loss on LP header	0 MMBtu/h	
Option 2 - % of heat lost on HP header		
Option 2 - % of heat lost on MP header	0.1 %	
Option 2 - % of heat lost on LP header	0.1 %	
<small>Note: Losses calculated as the percentage of heat flow entering each header</small>		
<small>Note: Current values for heat entering headers are: HP 57 MMBtu/h, MP 36 MMBtu/h, LP 13 MMBtu/h - These may change when the model is updated</small>		

These values are entered into this section to increase the accuracy of the model. In order to generate a conservative model of this particular system, these associated heat losses were not considered. The remaining data that is required includes the Steam Distribution and Process Condensate sections, as shown in Figure 14 and Figure 15.

Figure 14. Steam Distribution

Steam Distribution	Input Data	Warnings
High Pressure (HP)	225 psig	
Medium Pressure (MP)	150 psig	
Low Pressure (LP)	15 psig	
HP Steam Use by Processes	17,151 kb/h	
MP Steam Use by Processes	19.3 kb/h	
LP Steam Use by Processes	4,605 kb/h	

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

Figure 15. Site Details Section

Process Condensate	Input Data	Warnings
Condensate return temperature to tank	130 F	
HP condensate recovery	0 %	
MP condensate recovery	5 %	
LP condensate recovery	5 %	

Note: Condensate recovery specified as the percentage of steam supplied to the processes at each level

Do you flash condensate to MP steam?

Do you flash condensate to LP steam?

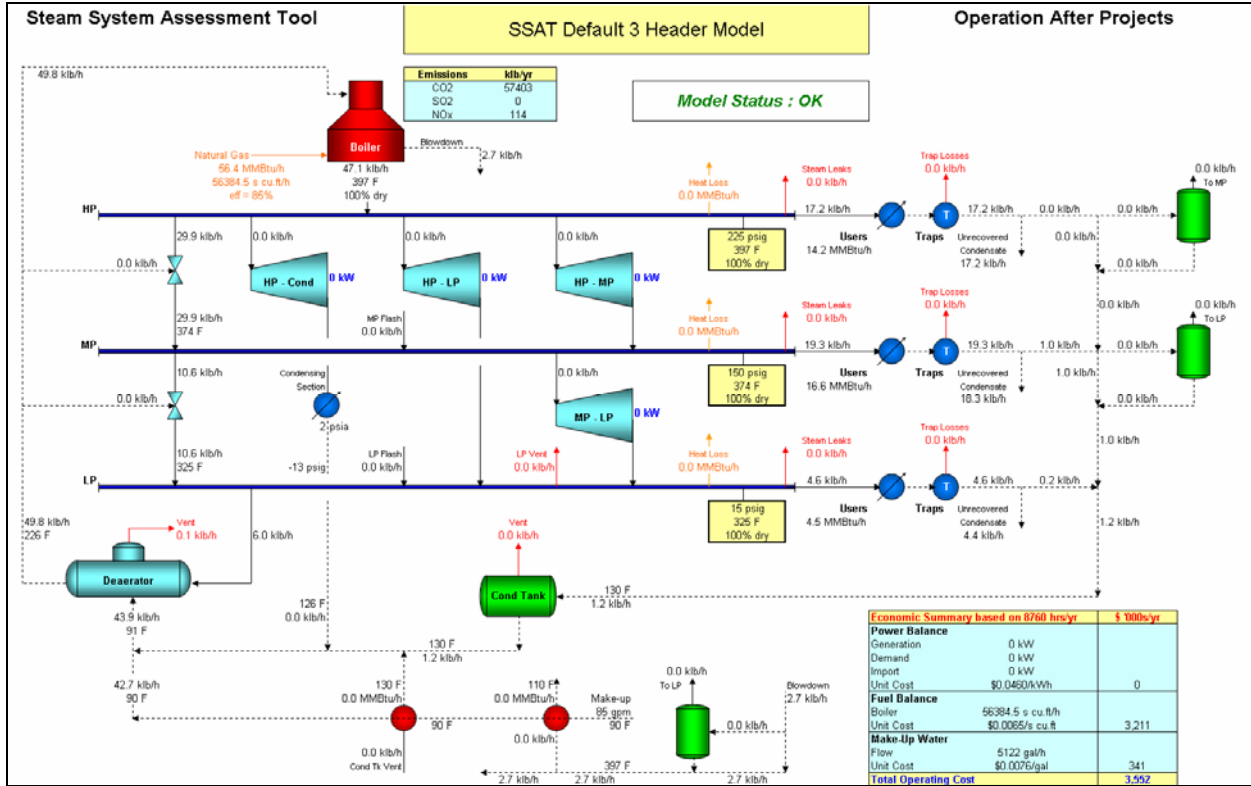
In the Steam Distribution section, the three line pressures are entered into the corresponding cells. When the average mass flowrate of steam for the medium-pressure line is unknown, its value is determined using the average steam production mass flowrate of the boiler and a guess and check method with the SSAT model. Average mass flowrates of steam are entered into the High-Pressure Steam Use by Processes Cell until the average mass flowrate of Boiler #1 steam production is attained. Based on this method, the average mass flowrate of the deaerator steam injection is 5,998 lb/hr. The average mass flowrates of steam for the high-and low-pressure lines were 17,151 lb/hr and 4,605 lb/hr, respectively. The remaining steam usage is the average mass flowrate for the medium-pressure line, which is calculated to be 19,301 lb/hr.

In the Process Condensate section, the average condensate return temperature is entered, as well as the high-pressure condensate recovery percentage. Since the steam from the high-pressure line is exported to a neighboring plant and not returned, the condensate return percentage is considered to be zero percent. The condensate return percentages for the medium-and low-pressure lines are unknown. The model can be used to determine the unknown condensate return percentages. Using the average mass flowrate of the makeup water provided by the plant, the return percentages are adjusted until the average mass flowrate of the makeup water is attained. The resulting medium-and low-pressure condensate return percentages are both determined to be 5%.

The final calculation that is required is the total cost of makeup water, including chemical costs. This total cost is determined using the current annual water cost, current annual chemical cost and the annual makeup water consumption. The makeup water rate, MWR, is based on the average mass flowrate of makeup water, hours of boiler operation, plant city water costs, and the makeup water treatment cost. The calculated boiler makeup water rate is \$0.0076/gal.

With all of the necessary data entered, the steam system can be modeled by SSAT. The system is displayed in the Model Input Tab, as shown in Figure 16.

Figure 16. SSAT Steam System Model



The model illustrates the average mass flowrates, temperatures and pressures of the system. It also displays an economic summary of the system including the total cost of operation. The Results Summary displays the effects associated with entering a project into the model, as shown in Figure 17.

Figure 17. SSAT Results Tab

Steam System Assessment Tool			
3 Header Model			
Results Summary			
SSAT Default 3 Header Model			
Model Status : OK			
Cost Summary (\$ '000s/yr)	Current Operation	After Projects	Reduction
Power Cost	0	0	0 N/A
Fuel Cost	3,211	3,211	0 0.0%
Make-Up Water Cost	341	341	0 0.0%
Total Cost (in \$ '000s/yr)	3,552	3,552	0 0.0%
On-Site Emissions	Current Operation	After Projects	Reduction
CO2 Emissions	57403 klb/yr	57403 klb/yr	0 klb/yr 0.0%
SOx Emissions	0 klb/yr	0 klb/yr	0 klb/yr N/A
NOx Emissions	114 klb/yr	114 klb/yr	0 klb/yr 0.0%
Power Station Emissions	Reduction After Projects		Total Reduction
CO2 Emissions	0 klb/yr		0 klb/yr -
SOx Emissions	0 klb/yr		0 klb/yr -
NOx Emissions	0 klb/yr		0 klb/yr -
<small>Note: Calculates the impact of the change in site power input on emissions from an external power station. Total reduction values are for site + power station</small>			
Utility Balance	Current Operation	After Projects	Reduction
Power Generation	0 kW	0 kW	0 kW -
Power Import	0 kW	0 kW	0 kW N/A
Total Site Electrical Demand	0 kW	0 kW	- -
Boiler Duty	56.4 MMBtu/h	56.4 MMBtu/h	0.0 MMBtu/h 0.0%
Fuel Type	Natural Gas	Natural Gas	- -
Fuel Consumption	56384.5 s cu.ft/h	56384.5 s cu.ft/h	0 klb/yr 0.0%
Boiler Steam Flow	47.1 kbb/h	47.1 kbb/h	- -
Fuel Cost (in \$/MMBtu)	6.50	6.50	- -
Power Cost (as \$/MMBtu)	13.48	13.48	- -
Make-Up Water Flow	5122 gal/h	5122 gal/h	0 gal/h 0.0%
Turbine Performance	Current Operation	After Projects	Marginal Steam Costs
HP to LP steam rate	Not in use	Not in use	(based on current operation)
MP to HP steam rate	Not in use	Not in use	HP (\$/kbb) 9.91
MP to LP steam rate	Not in use	Not in use	MP (\$/kbb) 9.85
LP to Condensing steam rate	Not in use	Not in use	LP (\$/kbb) 9.85

In this Results Summary, reductions in emissions, boiler steam flowrate, natural gas, and makeup water are displayed as well as their associated cost savings resulting from entered projects. The Results Summary also displays the marginal steam costs for each of the pressure lines. The results can then be used to justify the implementation of a project for the actual boiler system. The assessment team, having SSAT, made recommendations based on the projects provided by the software.

Interactive Effects

One of the considerations when analyzing a boiler system is the concept of interactive effects. These effects exist when the implementation of one project affects the energy and cost savings of one or more different projects. One of the features of SSAT is its ability to analyze multiple projects at the same time, accounting for the influence of interactive effects. This can become beneficial when justifying the implementation of multiple projects at a plant.

Summary

The seven recommendations that were quantified through the use of SSAT will result in:

- Total Cost Savings: \$607,000/yr
- Total Budget Reduction: 7%
- Natural Gas Reduction: 11%
- Electricity Reduction: 3%
- City Water Reduction: 2%
- Simple Payback: 1.5 years

Conclusion

Due to rising cost of natural gas, industries are looking to reduce their energy consumption to protect their profit margins. The Steam System Assessment Tool is a modeling software that can help identify and quantify energy savings recommendations in order to reduce the natural gas consumption of a plant. This software is easy to use and can be downloaded for free at the U.S. Department of Energy website.

One of the main disadvantages of SSAT is that the software uses assumptions when creating a model, which cannot be altered by the user. On the plus side, these assumptions allow greater flexibility in identifying recommendations using the SSAT software. Another disadvantage is that if the boiler system does not contain specific equipment including a deaerator tank and a condensate return tank, a model will be difficult if not impossible to generate. The software also does not contain a reduce pressure recommendation, which is a common savings opportunity.

It can, however, provide plant personnel with quantifiable cost savings projects that can be used to reduce the operating cost of a boiler system. Since multiple projects can be modeled at the same time, interactive effects can be quantified. This software also reduces computational time associated with some projects that require iterative methods to determine cost savings. Despite the limitations of the software, SSAT is a useful tool in calculating energy savings.

The specific recommendations and associated figures that were presented briefly in this paper, along with additional figures and explanatory information, can be viewed in their full form online at: <http://www.erc.uic.edu/news/whatsnew.htm>.

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