SSAT Module
9/30/2009

<u>Slide 1:</u> Hello, and welcome to this introduction to the Steam System Assessment Tool.

<u>Slide 2:</u> Technology Delivery is a program area within the Industrial Technologies Program (ITP) that supports ITP's mission to improve the energy intensity of the U.S. industrial sector through a coordinated program of research and development, validation, and dissemination of energy-efficient technologies and practices. One of the ways Technology Delivery keeps you in touch with the latest developments is through training, publications, and software tools. This tool, the Steam System Assessment Tool, also known as 'the Assessment Tool', or its acronym, SSAT, is one of the software tools to help you identify energy saving opportunities to achieve your energy reduction goals.

<u>Slide 3:</u> Now, we will show you the Steam System Assessment Tool. This is an Excel-based software tool designed to model the entire steam system. It allows you to do project investigations, by doing a before-and-after analysis of different real-life steam projects.

Using steam system investigation techniques and the U.S. DOE Steam tools, system improvements, or projects, are identified. The Assessment Tool will be used to calculate the energy and economic impacts for these projects. These projects include boiler feedwater economizer installation, blowdown thermal energy recovery, condensate recovery, and insulation.

The initial investigation of our example system identified several areas where modifications could reduce energy consumption. We will use the SSAT to evaluate the impact of potential projects in some of these areas. We will see that sustainable real-world projects have the potential to reduce fuel cost more than 7 percent. It should be noted that the site fuel cost is 19,000,000 per year; therefore, the savings potential is 1,300,000 dollars per year.

Slide 4: After you open the SSAT, the first thing you will see is a list of templates to start with. There are three different basic system arrangements based on the number of steam pressures in the system. SSAT is arranged to have 1, 2, or 3 different pressure levels, utilizing combinations of high pressure, medium pressure, and low pressure. The SSAT templates are each available in US units or metric units. For now, let's click on SSAT 3 Header v3 US and hit the select button.

Select SSAT Template

SSAT Templates allow you to calculate predefined systems.
The structure of each template is locked and cannot be changed

Select one of the locked templates below:

	FileName	Title	FullName
	SSAT 1 Header v3 Metric.xls	1 Pressure Header Model v3 Metric	C:\Program Files\LM\ProSteam\Templates\SSAT 1 Header v3 Metric.xls
	SSAT 1 Header v3 US.xls	1 Pressure Header Model v3 US	C:\Program Files\LM\ProSteam\Templates\SSAT 1 Header v3 US.xls
	SSAT 2 Header v3 Metric.xls	2 Pressure Header Model v3 Metric	C:\Program Files\LM\ProSteam\Templates\SSAT 2 Header v3 Metric.xls
	SSAT 2 Header v3 US.xls	2 Pressure Header Model v3 US	C:\Program Files\LM\ProSteam\Templates\SSAT 2 Header v3 US.xls
	SSAT 3 Header v3 Metric.xls	3 Pressure Header Model v3 Metric	C:\Program Files\LM\ProSteam\Templates\SSAT 3 Header v3 Metric.xls
	SSAT 3 Header v3 US.xls	3 Pressure Header Model v3 US	C:\Program Files\LM\ProSteam\Templates\SSAT 3 Header v3 US.xls

US Units are BTU per hour per square inch-gauge, and degrees Fahrenheit.
Metric Units are Kilowatts, bar-gauge, and degrees Celcius.

Slide 7: The SSAT is a sophisticated steam system modeling tool that is based in Excel. The tool allows the user to configure a model of their industrial steam system. SSAT completes comprehensive mass and energy balances on the system.

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)	15000 kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0700 $/kWh	Typical 2003 value: $0.05/kWh
Operating hours per year	8760 hrs	
Site Make-Up Water Cost	0.0025 $/gallon	Typical 2003 value: $0.0025/gallon
Make-Up Water Temperature	70 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	10.00 $	Typical 2003 value: $5.78/(1,000 s cu.ft)

Built into SSAT are many of the energy management projects commonly addressed in industrial steam systems.

Slide 8: The user can turn these projects on or off and when fuel and electricity cost data are input the economic impacts of the projects can be determined. SSAT provides a side-by-side comparison of the original system and the system operating with the selected projects implemented.

Steam System Assessment Tool 3 Header Model Projects Entry Form		
Use this form to specify improvement projects. These projects will then be modeled and compared to the existing operation.		
Project 1 - Steam Demand Savings (Changing the process steam requirements) Current use - HP: 50 klb/h (40.22 MMBtu/h) MP: 100 klb/h (86.25 MMBtu/h) LP: 200 klb/h (179.82 MMBtu/h)		
Do you wish to specify steam demand savings?		No
If yes, enter HP steam saving	0 klb/h	
If yes, enter MP steam saving	0 klb/h	
If yes, enter LP steam saving	1 klb/h	
Note: A negative saving can be entered to model an increase in steam demand Note: The savings have been converted to heat duties of 0.00 MMBtu/h (HP), 0.00 MMBtu/h (MP) and 0.00 MMBtu/h (LP) based on current header enthalpies Note: These heat duties are then used to determine the actual flow change in the Projects Model based on the calculated header enthalpies		
Project 2 - Use an Alternative Fuel Existing Boiler Fuel : Natural Gas Fuel Cost : $0.00578/s cu.ft		
Do you wish to specify an alternative fuel?		No

Slide 9: This allows the energy and economic impacts of the system improvements to be identified.

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	9,198	9,198	0	0.0%
Fuel Cost	33,575	31,976	1,599	4.8%
Make-Up Water Cost	361	361	0	0.0%
Total Cost (in $ '000s/yr)	**43,134**	**41,535**	**1,599**	**3.7%**

On-Site Emissions	Current Operation	After Projects	Reduction	
CO2 Emissions	390200 klb/yr	371619 klb/yr	18581 klb/yr	4.8%
SOx Emissions	0klb/yr	0 klb/yr	0 klb/yr	N/A
NOx Emissions	772 klb/yr	736 klb/yr	37 klb/yr	4.8%

Slide 10: Once you have selected the template for the number of pressure headers and units, you can begin to enter specific data for your site to build the model. Let's assume we have already entered the data into the three header template, saved it, and are re-opening the file for further use. Go to 'File',

Slide 12: 'Open',

Slide 15: Click on desktop or wherever you saved the file.

Slide 16: select the file you want to open. I will select the file I previously created and saved. Select the file SSAT - 'Introduction-Base EFF

Slide 17: and hit 'Open'.

Slide 19:Click OK.

Slide 20: We will use this model for our example throughout this course."“We are already looking at the first tab, ‘Input.’ It contains the Data Entry Form for your steam system. It is broken into two sections, ’Quick Start

Quick Start

Enter Case Description	SSAT Default 3 Header Model		
General Site Data	**Input Data**		**Notes/Warnings**
Site Power Import (+ for import, - for export)	15000	kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0700	$/kWh	Typical 2003 value: $0.05/kWh
Operating hours per year	8760	hrs	
Site Make-Up Water Cost	0.0025	$/gallon	Typical 2003 value: $0.0025/gallon
Make-Up Water Temperature	70	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	10.00	$	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)			
For user defined fuels, enter HHV	20000	Btu/lb	
Note: Emissions cannot be calculated for user defined fuels			
Steam Distribution	**Input Data**		**Warnings**
High Pressure (HP)	400	psig	
Medium Pressure (MP)	150	psig	
Low Pressure (LP)	20	psig	
HP Steam Use by Processes	20	klb/h	
MP Steam Use by Processes	40	klb/h	
LP Steam Use by Processes	170	klb/h	
Note: Enter process steam use at each pressure level. Excludes turbines, letdowns, leaks, trap losses, deaeration steam and vents			

Slide 21: and 'Site Detail.' '

Site Detail		
Boiler		
Method for specifying boiler efficiency		Option 2 - Enter User Defined Value
Note: Model default efficiencies represent Best Practice values assuming good operation and the installation of an economizer		
Option 2 - Enter efficiency (%)	80 %	
Note: Boiler efficiency is defined as 100% - Stack Loss (%) - Shell Loss (%). The "Stack Loss" sheet gives more information on heat losses Note: Efficiency is based on Higher Heating Value. Economizers are included in the boiler efficiency. Boiler blowdown losses are excluded		
Blowdown Rate (% of feedwater flow)	6 %	
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 2- User-defined superheated Conditions
Note: As a default, the model will use HP steam with 100 F of superheat. At HP pressure (600 psig), this corresponds to a temperature of 589 F		
Option 2 - Enter temperature	700 F	
Option 3 - Enter thermodynamic quality	99 % dry	
Note: Saturation temperature at specified HP pressure (600 psig) is 489 F Note: Steam quality is an expression of the percentage dryness (or vapor fraction) of the steam		

Slide 22: Quick Start' allows you to enter general information for your site.

Slide 24: 'Site Detail' allows you to give more detailed information about your site and how the steam system operates.

Slide 26: "Under 'Quick Start,' you can i nput basic information such as the site's utility rates (electrical, water, and fuel),

General Site Data	Input Data		Notes/Warnings
Site Power Import (+ for import, - for export)	15000	kW	Power import + site generated power = site electrical demand
Site Power Cost	0.0700	$/kWh	Typical 2003 value: $0.05/kWh
Operating hours per year	8760	hrs	
Site Make-Up Water Cost	0.0025	$/gallon	Typical 2003 value: $0.0025/gallon
Make-Up Water Temperature	70	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	10.00	$	Typical 2003 value: $5.78/(1,000 s cu.ft)

the generated steam pressure, the process steam consumption,

Steam Distribution	Input Data		Warnings
High Pressure (HP)	400	psig	
Medium Pressure (MP)	150	psig	
Low Pressure (LP)	20	psig	
HP Steam Use by Processes	20	klb/h	
MP Steam Use by Processes	40	klb/h	
LP Steam Use by Processes	170	klb/h	

as well as steam-to-electric generation configurations.

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

Slide 28: and the number of steam traps in the distribution system.

Steam Traps	Input Data	Warnings
Number of traps at each pressure level		
Traps on HP header	50 traps	
Traps on MP header	500 traps	
Traps on LP header	3000 traps	
Select the approximate timing of your last trap testing and maintenance program		3-5 years ago

All of these help the Assessment Tool make calculations that will show up in the 'Models' and the 'Results' tabs, which we will show you in a minute.

Slide 30: Under 'Site Detail,' you can input more detailed information and operating parameters for the boiler,

Boiler		
Method for specifying boiler efficiency		Option 2 - Enter User Defined Value
Note: Model default efficiencies represent Best Practice values assuming good operation and the installation of an economizer		
Option 2 Enter efficiency (%)	80 %	
Note: Boiler efficiency is defined as 100% - Stack Loss (%) - Shell Loss (%). The "Stack Loss" sheet gives more information on heat losses Note: Efficiency is based on Higher Heating Value. Economizers are included in the boiler efficiency. Boiler blowdown losses are excluded		
Blowdown Rate (% of feedwater flow)	6 %	No
Do you have blowdown flash steam recovery to the LP system?		
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 2- User-defined superheated Conditions
Note: As a default, the model will use HP steam with 100 F of superheat. At HP pressure (600 psig), this corresponds to a temperature of 589 F		
Option 2 Enter temperature	700 F	
Option 3 - Enter thermodynamic quality	99 % dry	
Note: Saturation temperature at specified HP pressure (600 psig) is 489 F Note: Steam quality is an expression of the percentage dryness (or vapor fraction) of the steam		

the steam turbines,

HP to LP Steam Turbine(s)	Input Data		Notes/Warnings
Isentropic efficiency	65	%	
Note: If multiple turbines are installed, the operation of the impact turbine (the turbine affected by changes to the system) should be modeled Note: A generator electrical efficiency of 100% is assumed by the model			
Select the appropriate turbine operating mode			Option 2 - Fixed Operation
Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand			
Option 2 - How should the fixed turbine operation be defined?			Specify fixed steam flow
Option 2 - Fixed steam flow	100	klb/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 **Option 3** - Maximum steam flow	50 150	klb/h klb/h	
Option 3 - Minimum power generation **Option 3** - Maximum power generation	1500 2500	kW kW	

Slide 31: the deaerator, feedwater heat recovery system, and process condensate.

Deaerator	Input Data		Warnings
Vent (as % of boiler feedwater flow)	0.1	%	
Note: Values of around 0.1% are typical			
Select the appropriate deaerator operating mode			Option 2 - User-defined pressure
Option 2 - Specify pressure	10	psig	
Note: Deaerator uses LP steam. Specified LP pressure is 20 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	180	F	
HP condensate recovery	0	%	
MP condensate recovery	70	%	
LP condensate recovery	50	%	
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

Slide 34: You can also allow the program to estimate steam losses such as the number of failed traps, the number of steam leaks,

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	10	traps	
Trap failures on MP header	30	traps	
Trap failures on LP header	250	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: 25, Loss per trap 0.134 klb/h - Total trap loss = 3.36 klb/h. Steam leaks: 10, Loss per leak 0.033 klb/h - Total leaks = 0.33 klb/h.
MP header - Trap failures: 30, Loss per trap 0.038 klb/h - Total trap loss = 1.14 klb/h. Steam leaks: 12, Loss per leak 0.010 klb/h - Total leaks = 0.11 klb/h.
LP header - Trap failures: 50, Loss per trap 0.003 klb/h - Total trap loss = 0.13 klb/h. Steam leaks: 20, Loss per leak 0.001 klb/h - Total leaks = 0.01 klb/h.

Slide 35: and header heat losses.

Insulation Heat Losses	**Input Data**		**Notes/Warnings**
Choose a method for specifying heat losses			Option 1 - Losses automatically estimated by model (Model default)
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 533 MMBtu/hr, MP 122 MMBtu/hr, LP 295 MMBtu/hr - These may change when the model is updated

Slide 36: Users can enter more precise estimations of these losses if known.

"Now, we click on the 'Model ' tab to see what we have come up with.

Begin Model Tab

Slide 39: Model Tab – Visual Description of Schematic

Model Tab Schematic Visual Description

This schematic represents a three-pressure steam system, and all of its components.

On the top left, it says "Steam System Assessment Tool."

The top center will contain the descriptive title provided by the user, the initial template reads "SSAT Default 3 Header Model" or a similar title for whatever model you chose. Below it, you will see the Model Status, which should read "OK." The model status provides an indication of the calculation condition of the model.

To the left of the Model Status, you will see a chart in light blue, which indicates the emissions per year for carbon dioxide, sulfur oxide, and nitrogen oxide.

At the top right, it will say "Current Operation" if you are on the Model tab, or "Operation After Projects" if you are on the Projects Model tab.

The red graphic near the top left represents the boiler. From the left, there is a dotted line entering it, which represents the amount of feedwater entering the boiler from the deaerator.

Also to the left of the boiler, we see the following information highlighted in orange: the type of fuel being used in the boiler, the fuel input energy, the fuel flow rate, and the boiler efficiency.

To the right of the boiler, we see a dotted line pointing to the right and then down, with a number next to it, indicating the amount of boiler blowdown.

Below the boiler, we see the amount of steam that is entering the high-pressure header, the temperature of it, and the thermodynamic quality of the steam.

The steam exits the boiler and enters the high-pressure header, represented by a dark blue line. Under the line, to the far left, you will see a light-blue triangular graphic that represents a pressure-reducing station. The pressure reducing station is also equipped with a desuperheating station. The number at the top indicates the amount of steam entering the pressure reducing valve. The number at the center-left of the valve indicates the amount of desuperheating water entering the unit. The number below indicates the amount of desuperheated steam entering the medium-pressure header; as well as the temperature of the steam.

To the right of the pressure-reducing station, you will see light blue, cone-shaped graphics, that represent the steam turbines. The one nearest to the left is a high-pressure to condensing turbine. This turbine discharges to the condenser represented by the blue circle below the turbine. The turbine exhaust pressure is noted as the condenser pressure. The turbine in the middle receives high-pressure steam and exhausts low-pressure steam. The one to the right receives high-pressure steam and exhausts medium-pressure steam. Above each turbine is an indication of the amount of steam coming into the turbine from the header. To the right, in dark blue, you see the power generation of the turbine.

In the center of the medium-pressure and low-pressure headers, we see an arrow pointing downward, which indicates the amount of flash entering the header from the condensate collection flash vessels that are located at the far-right of the schematic.

Above the header, to the right, the amount of heat loss is expressed in orange. Below, there is a yellow box that indicates the pressure, temperature, and thermodynamic quality of the steam.

The arrow to the right of the header points to a dark blue circle with a line through it, indicating the steam end-use components. Below this symbol is an indication of the thermal energy supplied to the end-use components from the steam. The end-use components discharge condensate through a steam trap, represented by a blue circle with a "T" in it. Schematically, condensate passes to the right through the trap. Failed steam traps that are blowing steam to the atmosphere are represented with the red arrow exiting the top of the trap symbol. The condensate appropriately passing through traps, again represented as exiting to the right of the trap, can be recovered or lost. Lost condensate is represented as the unrecovered condensate discharging down from the traps and recovered condensate enters the condensate collection system further to the right.

The green figures to the far-right of the schematic represent condensate flash-vessels. The top flash-vessel receives condensate from the high-pressure end-users. Flash-steam is formed because the flash vessel operates at medium-pressure but it receives saturated liquid condensate at high-pressure. As equilibrium is reached flash-steam is formed. This flash-steam exits the vessel through the top and is directed to the medium-pressure steam header, which is shown in the center of the diagram. Condensate exits the flash vessel and enters the medium-pressure condensate collection system. The medium-pressure condensate system is equipped with similar equipment as the high-pressure system.

All of the collected condensate enters the main condensate receiver located in the lower-center of the schematic. Process condensate is mixed with turbine condensate and makeup water prior to entering the deaerator.

The steam system deaerator is represented at the lower-left of the schematic. The deaerator receives low-pressure steam to preheat the collected condensate and makeup water represented as entering from the bottom of the vessel. Boiler feedwater discharges from the deaerator to the left and up to the boiler. The line pointing out from the top of the deaerator and leading to the right shows the amount of steam escaping from the vent.

Below the condensate receiver are the makeup water system and the blowdown system. The blowdown system is the green vessel shown on the schematic. This unit receives the boiler blowdown and allows flash-steam to be generated. The flash-steam can be recovered to the low-pressure header, as shown on the schematic, or it can be lost from the system. The remaining liquid blowdown exiting the bottom of the blowdown flash tank becomes part of the makeup water stream. Flow rates are indicated for all of these streams. The makeup water passes through two heat recovery heat exchangers represented as red circles on the schematic. These heat exchangers allow thermal energy to be recovered from the condensate receiver flash steam and the blowdown liquid.

The table at the bottom right shows an economic summary for the steam system that is being modeled based on the input model conditions . On the right of the table, you see total operating cost in thousands of dollars per year.

'Power balance' shows the amount of power generated onsite, the amount of power imported, and the combined total site demand.

'Fuel balance' shows the amount of fuel consumed and the unit cost of the fuel.

'Make-up water' shows the flow of makeup water in gallons per hour, and the unit cost per gallon.

At the bottom, the total operating cost is in thousands of dollars per year.

Slide 39: As you can see, there is a visual representation of your site, including the boiler, turbines, pressure reducing stations, steam demands, and feedwater preparation components, including deaerator and the condensate tank.

The steam system model includes all of the major steam system components. However, it does not provide unlimited components and arrangements. The model is limited in extent for two primary reasons. First, the complexity is limited to allow it to be easily understood with minimal training. Second, the model is configured to ensure the users focus attention on the components that are impacted by changes in the steam system. In other words, the configuration forces the user to identify the components in their real system that will respond to changes in the steam system.

For example, a real steam system may include two boilers operating with different fuels. One boiler (and fuel) may serve as the base-load component while the other boiler responds to changes in steam system demand. If the base-load boiler is not impacted by changes in steam demand then there will be no difference (or impact) noted in the base-load boiler. As a result, only the impact boiler characteristics need to be modeled. Even though the model is limited in extent it serves as a powerful evaluation tool even for very complex steam systems.

Also note that the Economic Summary calculations at the bottom right of the 'Model' tab are made based on what was typed in the 'Input' tab. If you look at this table, you will see the annual cost results for power balance, fuel balance, and make-up water, based on the information you input. Keep in mind that the totals are in thousands per year. The total annual operating cost is at the bottom at 43,134,000 dollars.

Again, the results are based on the information provided to the 'Input' tab.

Begin Projects Input Tab

Slide 40: The 'Projects Input' tab is where you can start doing a what-if analysis, and calculate what kinds of savings you would get if you were to implement certain changes within the steam system at your site. The 'Input' reflects the conditions of your original steam system while the 'Projects Input' tab contains the changes you would like to make to improve performance of the original steam system. There is a list of 18 potential projects listed in the "Projects Input" tab.

Steam System Assessment Tool

3 Header Model

Projects Entry Form

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

Project 1 - Steam Demand Savings (Changing the process steam requirements)

Current use - HP: 50 klb/h (40.22 MMBtu/h) MP: 100 klb/h (86.25 MMBtu/h) LP: 200 klb/h (179.82 MMBtu/h)

Do you wish to specify steam demand savings?		No
If yes, enter HP steam saving	0 klb/h	
If yes, enter MP steam saving	0 klb/h	
If yes, enter LP steam saving	1 klb/h	

Note: A negative saving can be entered to model an increase in steam demand

Note: The savings have been converted to heat duties of 0.00 MMBtu/h (HP), 0.00 MMBtu/h (MP) and 0.00 MMBtu/h (LP) based on current header enthalpies

Note: These heat duties are then used to determine the actual flow change in the Projects Model based on the calculated header enthalpies

Project 2 - Use an Alternative Fuel

Existing Boiler Fuel : Natural Gas Fuel Cost : $0.00578/s cu.ft

Do you wish to specify an alternative fuel?		No
Site Fuel Cost	0.67 $/MMBtu	Typical 2002 values: $2-6/MMBtu

Note: Example HHV values - Nat Gas 23,311 Btu/lb, No. 2 FO 19,400 Btu/lb, Typical Eastern Coal 13,710 Btu/lb, Green Wood 5,251 Btu/lb

For user defined fuels, enter HHV	15000 Btu/lb	

Note: Emissions cannot be calculated for user defined fuels

Project 3 - Change Boiler Efficiency Existing Efficiency : 85%		
Do you wish to specify a new boiler efficiency?		Yes
Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency		
If yes, enter new boiler efficiency (%)	84 %	
Note: Typical Best Practice boiler efficiency for Natural Gas is 85%		

Project 4 - Change Boiler Blowdown Rate Existing Blowdown Rate : 2%		
Do you wish to specify a new boiler blowdown rate?		No
If yes, enter new rate (% of feedwater flow)	1 %	

Project 5 - Blowdown Flash to LP Not currently installed	
Do you wish to modify the blowdown flash system?	Option 2 - No change

Project 6 - Change Steam Generation Conditions Existing Conditions : 600 psig. Superheated steam at 589 F		
Do you wish to change the HP steam generation conditions?		Option 3 - No change
Option 1 - Enter temperature	600 F	
Note: Saturation temperature at specified HP pressure (600 psig) is 489 F		
Option 2 - Enter thermodynamic quality	99.9 % dry	

Project 7 - HP to LP Steam Turbine(s) Efficiency : 65% Operation : Balances LP Header			
Do you wish to modify the HP to LP turbine operation?			No
If yes, select the appropriate turbine operating mode			Option 1 – Balances LP header
Note: If Option 1 is chosen, the model will preferentially use the HP to LP turbine to balance the LP demand			
Specify a new isentropic efficiency (%)		70 %	
Note: A generator electrical efficiency of 100% is assumed by the model Note: Isentropic efficiency of existing turbine is 65%			
Option 2 - How do wish to define the fixed turbine operation?			Option 2 Not Selected
Option 2 - Fixed steam flow		100 klb/h	
Option 2 - Fixed power generation		2000 kW	
Option 3 - How do wish to define the operating range?			Option 3 Not Selected
Option 3 - Minimum steam flow		50 klb/h	
Option 3 - Maximum steam flow		150 klb/h	
Option 3 - Minimum power generation		1500 kW	
Option 3 - Maximum power generation		2500 kW	

Project 8 - HP to MP Steam Turbine(s) Efficiency : 65% Operation : Balances MP Header			
Do you wish to modify the HP to MP turbine operation?			No
If yes, select the appropriate turbine operating mode			Option 1 - Balances LP header
Specify a new isentropic efficiency (%)		70 %	
Note: A generator electrical efficiency of 100% is assumed by the model Note: Isentropic efficiency of existing turbine is 65%			

Option 2 - How do wish to define the fixed turbine operation?			Option 2 not selected
Option 2 - Fixed steam flow		100 klb/h	
Option 2 - Fixed power generation		2000 kW	
Option 3 - How do wish to define the operating range?			Option 3 not selected
Option 3 - Minimum steam flow		50 klb/h	
Option 3 - Maximum steam flow		150 klb/h	
Option 3 - Minimum pow er generation		1500 kW	
Option 3 - Maximum pow er generation		2500 kW	

Project 9 - MP to LP Steam Turbine(s) Not installed		
Do you wish to modify the MP to LP turbine operation?		No
If yes, select the appropriate turbine operating mode		Option 1 - Balances LP header
Specify a new isentropic efficiency (%)	70 %	

Note: A generator electrical efficiency of 100% is assumed by the model

Note: Isentropic efficiency of existing turbine is 65%

Option 2 - How do wish to define the fixed turbine operation?			Option 2 not selected
Option 2 - Fixed steam flow		100 klb/h	
Option 2 - Fixed power generation		2000 kW	
Option 3 - How do wish to define the operating range?			Option 3 not selected
Option 3 - Minimum steam flow		50 klb/h	
Option 3 - Maximum steam flow		150 klb/h	
Option 3 - Minimum pow er generation		1500 kW	
Option 3 - Maximum pow er generation		2500 klb/h	

Project 10 - HP to Condensing Steam Turbine(s) Not installed		
Do you wish to add an HP to condensing turbine?		No, maintain current operation
If yes, enter a new isentropic efficiency (%)	70 %	
Note: A generator electrical efficiency of 100% is assumed by the model		
If yes, select the units to specify the condenser pressure		psia
New condenser pressure (psia)	2	
If yes, select the new mode of operation		Option 1 – F ixed Power generation
Option 1 - Fixed power generation	1000 kW	
Option 2 - Fixed steam flow	50 klb/h	

Project 11 - Feedwater Heat Recovery Exchanger using Condensate Tank Vent Not currently installed	
Modify the condensate tank vent heat recovery system?	No
Note: An approach temperature of 20 F will be assumed for a new exchanger	

Project 12 - Feedwater Heat Recovery Exchanger using Boiler Blowdown Not currently installed	
Modify the boiler blowdown heat recovery system?	No
Note: An approach temperature of 20 F will be assumed for a new exchanger	

Project 13 - Condensate Recovery Currently recover 50% of HP, 50% of MP and 50% of LP at 150 F		
Do you wish to specify new condensate recovery rates?		No
If yes, enter new HP condensate recovery	75 %	
If yes, enter new MP condensate recovery	75 %	
If yes, enter new LP condensate recovery	75 %	

Note: Condensate return temperature will be assumed to be 150 F as for the current operation

Project 14 - Condensate Flash to MP Not currently installed	
Do you wish to modify the MP condensate flash system?	No

Project 15 - Condensate Flash to LP Not currently installed	
Do you wish to modify the LP condensate flash system?	No

Project 16 - Steam Trap Losses Losses estimated automatically by model - Last maintenance program 3-5 years ago		
Do you wish to model the impact of a maintenance program?		No

Note: For Option 1, the model estimates a new trap failure rate. The rate reported is for 6 months after the maintenance program is carried out

Option 2 - Trap failures on HP header	5	
Option 2 - Trap failures on MP header	5	
Option 2 - Trap failures on LP header	5	

Note: Calculated values based on current user inputs are:-
HP header - Trap failures: 25, Loss per trap 0.134 klb/h - Total trap loss = 3.36 klb/h.
MP header - Trap failures: 30, Loss per trap 0.038 klb/h - Total trap loss = 1.14 klb/h.
LP header - Trap failures: 50, Loss per trap 0.003 klb/h - Total trap loss = 0.13 klb/h.

Project 17 - Steam Leaks Losses estimated automatically by model - Last maintenance program 3-5 years ago		
Do you wish to model the impact of a maintenance program?	No	
Note: For Option 1, the model estimates a new steam leakage rate. The rate reported is for 6 months after the maintenance program is carried out		
Option 2 - Steam leaks on HP header	5	
Option 2 - Steam leaks on MP header	5	
Option 2 - Steam leaks on LP header	5	

Note: Calculated values based on current user inputs are:-
HP header - Steam leaks: 10, Loss per leak 0.033 klb/h - Total leaks = 0.33 klb/h.
MP header - Steam leaks: 12, Loss per leak 0.010 klb/h - Total leaks = 0.11 klb/h.
LP header - Steam leaks: 20, Loss per leak 0.001 klb/h - Total leaks = 0.01 klb/h.

Project 18 - Improved Insulation Currently modeled based on percentage heat loss on each header	
Do you wish to model the impact of improved insulation?	No
Note: Model will assume that heat losses are reduced to 10% of the current value by improving insulation	

Slide 42: Only one of the 18 projects is selected at this time, and for the rest of them, "No" is selected after the question line, in yellow.

Project 3 - Change Boiler Efficiency Existing Efficiency : 80%		
Do you wish to specify a new boiler efficiency?		Yes
Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency		
If yes, enter new boiler efficiency (%)	84 %	
Note: Typical Best Practice boiler efficiency for Natural Gas is 85%		

If you want to try a project, or a combination of several projects, click on the drop-down menu next to the question, and click "Yes."

Slide 43: *Drop Down Menu selected*

Project 16 - Steam Trap Losses Losses estimated automatically by model - Last maintenance program 3-5 years ago		
		Drop Down Menu:
		Option 1 – Yes, model to estimate new loss values
		Option 2 – Yes, enter new number of failed traps
		No
Do you wish to model the impact of a maintenance program?		Option 1 – Yes, model to estimate new loss values
Note: For Option 1, the model estimates a new trap failure rate. The rate reported is for 6 months after the maintenance program is carried out		
Option 2 - Trap failures on HP header	5	
Option 2 - Trap failures on MP header	5	
Option 2 - Trap failures on LP header	5	
Note: Calculated values based on current user inputs are:- HP header - Trap failures: 25, Loss per trap 0.134 klb/h - Total trap loss = 3.36 klb/h. MP header - Trap failures: 30, Loss per trap 0.038 klb/h - Total trap loss = 1.14 klb/h. LP header - Trap failures: 50, Loss per trap 0.003 klb/h - Total trap loss = 0.13 klb/h.		

Slide 44: Once you do that, you can change certain information.

<u>Slide 48:</u> For example, we can change the boiler efficiency using Project 3 Change Boiler Efficiency. As you can see, it is now 80 percent. Here, we can change it to 84 percent, which might model the impact of installing a feedwater economizer on the boiler, which we do not have in our current boiler system.

Project 3 - Change Boiler Efficiency Existing Efficiency : 80%		
Do you wish to specify a new boiler efficiency?		Yes
Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency		
If yes, enter new boiler efficiency (%)	84 %	
Note: Typical Best Practice boiler efficiency for Natural Gas is 85%		

Begin Projects Model Tab

<u>Slide 52:</u> Now, let's take a look at the tab 'Projects Model.'

[Refer back to '<u>Slide 39:</u> Model Tab – Visual Description of Schematic'. Changes between the "Projects Model" and "Model" tabs will be discussed in the next slides.]

<u>Slide 55:</u> The 'Projects Model' tab is just like the 'Model' tab that we showed you before, except for the fact that it shows how the values have changed after we made changes in the "Projects Input" tab.

Look up here, and you'll see that the boiler efficiency is 84 percent, because that is what we changed it to in the 'Projects Input' tab.

Natural gas →
364.7 MMBtu/h
364575.3 s cu.ft/h
eff = 84%

Boiler efficiency is 84%

So let's go back to the "Model" tab, which reflects our original boiler efficiency.

Back to Model Tab

Slide 56: Notice that the boiler efficiency was originally 80 percent.

Natural gas →
383.4 MMBtu/h
383278.3 s cu.ft/h
eff = 80%

So, by looking at both models, you can see the changes. OK, so let's look at a couple of other things. As you can see, the model calculates electricity impacts, fuel impacts, and economic impacts in the Economics Summary table.

Economic Summary based on 8760 hrs/yr		$ '000s/yr
Power Balance		
Generation	7513 kW	
Demand	22513 kW	
Import	15000 kW	
Unit Cost	$0.0700/kWh	9,198
Fuel Balance		
Boiler	383278.3 s cu.ft/h	
Unit Cost	$0.01/s cu.ft	33,575
Make-Up Water		
Flow	16469 gal/h	
Unit Cost	$0.0025/gal	361
Total Operating Cost		**43,134**

Slide 57: The projects also impact environmental emissions. Emissions impacts for the site are based on the selected fuel. Carbon dioxide and sulfur dioxide emissions are based on the selected fuel composition. Oxides of nitrogen emissions are estimates based on U.S.EPA data for typical boilers operating with the selected fuel.

Emissions	klb/yr
CO2	390200
SO2	0
NOx	772

To see a summary of the Current vs. Proposed Projects without flipping between the two tabs, you can click on the 'Results' tab.

Begin Results Summary 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	9,198	9,198		0	0.0%
Fuel Cost	33,575	31,976		1,599	4.8%
Make-Up Water Cost	361	361		0	0.0%
Total Cost (in $ '000s/yr)	**43,134**	**41,535**		**1,599**	**3.7%**
On-Site Emissions	**Current Operation**	**After Projects**		**Reduction**	
CO2 Emissions	390200 klb/yr	371619 klb/yr		18581 klb/yr	4.8%
SOx Emissions	0klb/yr	0 klb/yr		0 klb/yr	N/A
NOx Emissions	772 klb/yr	736 klb/yr		37 klb/yr	4.8%
Power Station Emissions		**Reduction After Projects**		**Total Reduction**	
CO2 Emissions		0 klb/yr		18581 klb/yr	-
Sox Emissions		0 klb/yr		0klb/yr	-
Nox Emissions		0 klb/yr		37 klb/yr	-

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

Utility Balance	Current Operation	After Projects	Reduction	
Power Generation	7513 kW	7513 kW	-	-
Power Import	15000kW	15000 kW	0 kW	0.0%
Total Site Electrical Demand	22513 kW	22513 kW	-	-
Boiler Duty	383.4 MMBtu/h	365.1 MMBtu/h	18.3 MMBtu/h	4.8%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	383278.3 s cu.ft/h	365027 s cu.ft/h	18251.3 s cu.ft/h	4.8%
Boiler Steam Flow	262.6 klb/h	262.6 klb/h	0.0 klb/h	0.0%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	20.51	20.51	--	
Make-Up Water Flow	16469 gal/h	16469 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)	
HP to MP steam rate	22 kWh/klb	22 kWh/klb	HP ($/klb)	----->
MP to LP steam rate	28 kWh/klb	28 kWh/klb	MP ($/klb)	----->
HP to Condensing steam rate	Not in use	Not in use	LP ($/klb)	----->

List of Selected Projects
Increase boiler efficiency

Gas Turbine Assessment
Your site is a good candidate for the installation of a gas turbine + waste heat boiler
Warnings - Any warnings listed below may impact on the validity of the simulation

Current Operation	**After Projects**

Slide 58: The energy costs/consumptions and emissions will be shown as well as the reduction in usage and the percentage reduction. Make sure this note indicates "Model Status: OK". The program is still calculating until this message appears. Please wait!

Model Status : OK

OK, now let's look at the difference in cost. As you can see, the Current total operating cost for our site is about 43,134,000 dollars per year. The cost went down to about 41,535,000 dollars. An improvement of 1,599,000 dollars per year or 3.7 percent of the operating costs! This is the impact of improving the efficiency of all steam generation at the site. If we were just targeting one boiler we could scale the results to estimate the individual boiler impact.

Cost Summary ($ '000s/yr)	**Current Operation**	**After Projects**		**Reduction**	
Power Cost	9,198	9,198		0	0.0%
Fuel Cost	33,575	31,976		1,599	4.8%
Make-Up Water Cost	361	361		0	0.0%
Total Cost (in $ '000s/yr)	**43,134**	**41,535**		**1,599**	**3.7%**

In our example, the Current Operation emissions indicate an estimated carbon dioxide emission is about 390,200 kilopounds per year, sulfur is 0, and nitrogen oxides are 772 kilopounds per year. The After Projects show a reduction of estimated carbon dioxide emissions to about 371,619, kilopounds per year, and nitrogen oxide emissions to 736 kilopounds per year. The percent reductions of 4.8% for each component are also calculated in the Results Summary table. So, you can see how much emissions are estimated to be reduced by increasing boiler efficiency a certain percentage!

On-Site Emissions	Current Operation	After Projects	Reduction	
CO_2 Emissions	390200 klb/yr	371619 klb/yr	18581 klb/yr	4.8%
SOx Emissions	0klb/yr	0 klb/yr	0 klb/yr	N/A
NOx Emissions	772klb/yr	736 klb/yr	37 klb/yr	4.8%

I klbs = 1,000 pounds

Slide 60: Scroll down the Results Summary page and you will see a list of 'Selected Proj ects.' This is a list of the projects that you are considering to implement. As of now, we only tried increasing boiler efficiency.

List of Selected Projects
Increase boiler efficiency

Let's go back and do one more project to see what kind of difference it makes." Because in these examples we want to see the impact of each potential project individually we will turn the boiler efficiency project off.

We'll click on the 'Projects Input' tab

Begin Projects Example – Project Input Tab

Slide 61: and go to 'Project 3 – Change Boiler Efficiency'. We will select 'No' to turn this project off.

Drop Down Menu selected

Project 3 - Change Boiler Efficiency Existing Efficiency : 80%		
		Drop Down Menu:
		Yes
		No
Do you wish to specify a new boiler efficiency?		No
Note: An example use of this project option is to model the effect of installing an economizer by increasing the efficiency		
If yes, enter new boiler efficiency (%)	84 %	
Note: Typical Best Practice boiler efficiency for Natural Gas is 85%		

Slide 64: Then we will scroll down to 'Project 13 – Condensate Recovery.'

Project 13 - Condensate Recovery Currently recover 0% of HP, 70% of MP and 50% of LP at 180 F		
Do you wish to specify new condensate recovery rates?		No
If yes, enter new HP condensate recovery	75 %	
If yes, enter new MP condensate recovery	75 %	
If yes, enter new LP condensate recovery	75 %	
Note: Condensate return temperature will be assumed to be 150 F as for the current operation		

Slide 66: In the Project 13 title block, you can see the data you entered at the 'Input' tab. You will see the system originally recovered no condensate for the high pressure header, 70 percent for the medium pressure header, and 50 percent for the low pressure header system.

Let us assume we have identified a heat exchanger that discharges condensate to the sewer. Using a bucket and a stopwatch, we measure approximately 7 gallons per minute of condensate lost to the drain. This will result in an opportunity to increase condensate recovery from the low-pressure steam system by 2 percentage points for this system.

To evaluate this potential project, we need to select 'yes' to specify new condensate recovery rates.

Drop Down Menu selected

Project 13 - Condensate Recovery Currently recover 0% of HP, 70% of MP and 50% of LP at 180 F		
		Drop Down Menu:
		Yes
		No
Do you wish to specify new condensate recovery rates?		Yes
If yes, enter new HP condensate recovery	75 %	
If yes, enter new MP condensate recovery	75 %	
If yes, enter new LP condensate recovery	75 %	
Note: Condensate return temperature will be assumed to be 150 F as for the current operation		

Slide 68: We are only increasing the condensate collection from the low-pressure system; therefore, we enter 0 percent for the high-pressure header…….

Slide 70: and 70 percent for the medium pressure header.

Slide 71: For the low-pressure header, we will enter 52 percent.

Project 13 - Condensate Recovery Currently recover 0% of HP, 70% of MP and 50% of LP at 180 F		
Do you wish to specify new condensate recovery rates?		Yes
If yes, enter new HP condensate recovery	0 %	
If yes, enter new MP condensate recovery	70 %	
If yes, enter new LP condensate recovery	52 %	
Note: Condensate return temperature will be assumed to be 150 F as for the current operation		

Now, let's click on the 'Results' tab to see what a difference it made.

Back to 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	9,198	9,198	0	0.0%
Fuel Cost	33,575	33,534	42	0.1%
Make-Up Water Cost	361	352	9	2.5%
Total Cost (in $ '000s/yr)	**43,134**	**43,084**	**50**	**0.1%**

On-Site Emissions	Current Operation	After Projects	Reduction	
CO2 Emissions	390200 klb/yr	389717 klb/yr	483 klb/yr	0.1%
SOx Emissions	0klb/yr	0 klb/yr	0 klb/yr	N/A
NOx Emissions	772 klb/yr	771 klb/yr	1 klb/yr	0.1%

Power Station Emissions		Reduction After Projects	Total Reduction	
CO2 Emissions		-8 klb/yr	475 klb/yr	-
SOx Emissions		0 klb/yr	0 klb/yr	-
NOx Emissions		0 klb/yr	1 klb/yr	-

Slide 74: This relatively small increase in condensate collection returns measurable benefits. If we can recover just 2 percent more of our low pressure condensate, our annual operating costs will be reduced 50,000 dollars. Our emissions will be reduced only slightly, yet saving 0.1 percent for carbon dioxide and nitrogen oxides. Th is project can also be relatively inexpensive to implement, so this is a good project to pursue.

Scroll down the 'Results tab' to the 'List of selected projects,'

Slide 76: and you will see that the project 'Increase LP Condensate Recovery' has been added to the list.

List of Selected Projects
Increase LP condensate recovery

Another feature of the tool is the Stack Loss Calculator. Click on the 'Stack Loss' tab.

Begin Stack Loss Tab

Slide 77: This calculator estimates the energy loss from the boiler stack. This tool could be used to determine the impact of improving combustion control, installing a feedwater economizer, or other exhaust gas related project. The previous boiler efficiency improvement example could have utilized this tool to evaluate the efficiency impact. To do this, it uses three inputs: stack gas temperature, ambient temperature, and stack gas oxygen content which you provide.

Steam System Assessment Tool Stack Loss Calculator			
Based on user inputs of Stack Temperature, Ambient Temperature and Stack Oxygen Content, an estimate will be provided of the heat loss from the boiler stack. Losses are expressed as a percentage of the heat fired.			
Stack losses are related to SSAT Boiler Efficiency as follows: **SSAT Boiler Efficiency = 100% - Stack Loss (%) - Shell Loss (%)** Shell Loss refers to the radiant heat loss from the boiler. Typically <1% at full load, 1-2% at reduced load.			
Input Data			
Stack Gas Temperature (°F)	450	°F	Stack Temperature - Ambient Temperature = 380°F
Ambient Temperature (°F)	70	°F	
Stack Gas Oxygen Content (%)	5	%	
Note: Stack gas oxygen content is expressed on a molar or volumetric basis			

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	**19.8**	**%**
Number 2 Fuel Oil	**15.5**	**%**
Number 6 Fuel Oil (Low Sulfur)	**15.0**	**%**
Number 6 Fuel Oil (High Sulfur)	**15.2**	**%**
Typical Eastern Coal (Bituminous)	**13.6**	**%**
Typical Western Coal (Subbituminous)	**15.1**	**%**
Typical Green Wood	**26.1**	**%**

For further information, scroll down for graphs of stack loss as a function of stack oxygen and temperature

Stack Loss Example

Determine the Stack Loss (Natural Gas)

Combustion analyzer data:

- Flue gas O2 content — 5% by volume
- Flue gas CO2 content — 6% by volume
- Flue gas CO content — ~0%
- Flue gas unburned fuel — ~0%
- Flue gas temperature — 450^{o}F (380^{o}F net)
- Intake air temperature — 70^{o}F
- Stack Loss — 21.2%
- Combustion Efficiency — 78.8%

Slide 78: We have already entered out values of 450 degrees Fahrenheit Flue Gas Temperature, 70 degrees Fahrenheit ambient temperature and 5 percent oxygen content. Let's drop the Flue Gas temperature to 300.

Stack Gas Temperature (°F)	300 °F	Stack Temperature - Ambient Temperature = 380°F

Slide 79: Look down at 'Results' and you can see the percentages of estimated stack losses for each type of fuel. So if you were using natural gas, the stack loss would be 15.7 percent.

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	**15.7**	**%**
Number 2 Fuel Oil	**11.5**	**%**
Number 6 Fuel Oil (Low Sulfur)	**11.0**	**%**
Number 6 Fuel Oil (High Sulfur)	**11.2**	**%**
Typical Eastern Coal (Bituminous)	**9.5**	**%**
Typical Western Coal (Subbituminous)	**11.1**	**%**
Typical Green Wood	**22.4**	**%**

For further information, scroll down for graphs of stack loss as a function of stack oxygen and temperature

Let's change our value back to 450 Fahrenheit.

Stack Gas Temperature (°F)	450 °F	Stack Temperature - Ambient Temperature = 380°F

<u>Slide 82:</u> Look down at Results again. Stack loss is now 19.8 percent. Because the stack loss is generally the most significant loss, boiler efficiency could be estimated at 80.2 percent.

Results

Estimated Stack Losses for each of the default fuels are as follows:

Natural Gas	**19.8**	**%**
Number 2 Fuel Oil	**15.5**	**%**
Number 6 Fuel Oil (Low Sulfur)	**15.0**	**%**
Number 6 Fuel Oil (High Sulfur)	**15.2**	**%**
Typical Eastern Coal (Bituminous)	**13.6**	**%**
Typical Western Coal (Subbituminous)	**15.1**	**%**
Typical Green Wood	**26.1**	**%**

For further information, scroll down for graphs of stack loss as a function of stack oxygen and temperature

100% - 19.8% = 80.2% boiler efficiency

A feedwater economizer could recover thermal energy from the flue gas allowing the exhaust gas to discharge at 300°F. The Stack Loss Calculator indicates the stack loss will decrease to 15.7 percent, which translates into a boiler efficiency of approximately 84.3 percent.

100% - 15.7% = 84.3% boiler efficiency

These efficiencies could be used in Project 3 – Change Boiler Efficiency like we did previously.

You can see the stack loss values for the other fuels listed in the Results table.

Scroll down, and you will see a chart for each type of fuel.

Slide 83: *Slide in Motion to show charts for each fuel type.*

Visual Description of Stack Loss Charts

There is a graph for the stack loss results for each type of fuel: natural gas, number 2 fuel oil, number 6 fuel oil (low sulfur content), number 6 fuel oil(high sulfur content), typical eastern coal, typical western coal, and typical green wood.

Each graph shows you stack loss based on the flue gas oxygen content and the net stack temperature. Net stack temperature is the difference in the measured stack temperature and the ambient temperature.

The numbers on the left going up and down from 5 to 30, represent the stack loss percentage.

The numbers on the bottom, going from left to right from 0 to 600, represent the net stack temperature in degrees Fahrenheit.

The lines on the graph each represent a different percentage of stack oxygen content. Black is 11, Brown is 9, pink is 7, blue is 5, green is 3, and red is 1. The stack loss percentage increases as the net stack temperature increases.

Slide 84: Each chart shows the estimated percent of heat loss from the stack, or the Stack Loss.

As a last feature of the tool, click on the 'User calculations' tab for a sheet on which you can make your own personal notes and calculations.

Begin User Calculations Tab

Slide 85: This tab is basically blank when you first open the templates. You may want to include any assumptions or data references that are part of the Model or Projects Inputs. Here you can see we have listed the Steam Plant Point of Contact, the date the stack temperature measurements were taken and the resulting initial boiler efficiency. We have also listed a few ideas we want to evaluate with the Assessment Tool. You can also enter and perform side calculations and list assumptions used for the calculations and inputs.

User Calculations Sheet			
This is a blank sheet provided for the user to make notes, carry out calculations etc.			
This is a blank sheet provided for the user to make notes, carry out calculations etc.			
Steam Plant Contact:	I.M. Steam		
	123-456-7890		
Stack Temperature Measurements Taken	March 4, 2009		
Initial Boiler Efficiency	80.20	%	
Ideas for Projects:			
Feedwater Economizer			
	Current Flue Gas Temperature	450	F
	Estimated New Flue Gas Temperature	300	F
	Adjusted Boiler Efficiency	84.30	%
Condensate Recovery			
	Measured Condensate Flow Rate	7.00	gallons per minute
Blowdown Flash to Low Pressure			
Feedwater Heat Recovery Exchanger			

Begin Summary Example

Summary Example

Slide 86: Now I'm going to show you how you can use the Scoping Tool to identify a project; then use the Assessment tool to estimate the potential savings of that project.

So, let's go back to the Scoping tool and take a look at the Summary Results, which is Tab Number 7.

Begin SSST – Tab 7 - Summary

Slide 88: Near the bottom of the page, at row 71, you can see the summary results of the major topics.

SUMMARY OF STEAM SCOPING TOOL RESULTS

SCOPING TOOL RESULTS	POSSIBLE SCORE	YOUR SCORE
STEAM SYSTEM PROFILING	90	60
STEAM SYSTEM OPERATING PRACTICES	140	100
BOILER PLANT OPERATING PRACTICES	80	53
DISTRIBUTION, END USE, RECOVERY OP. PRACTICES	30	19
TOTAL SCOPING TOOL QUESTIONAIRE SCORE	340	232
TOTAL SCOPING TOOL QUESTIONAIRE SCORE (%)		68.2%
Date That You Completed This Questionnaire)		03/04/09

Let's try to see where we got a particularly low score. Well, we didn't do too great under Boiler Plant Operating Practices. There were 80 possible points, and our example scored 53, which would be 66 percent.

BOILER PLANT OPERATING PRACTICES	80	53

53-60 = 66%

Move up the spreadsheet to this topic, row 40.

3. BOILER PLANT OPERATING PRACTICES	POSSIBLE SCORE	YOUR SCORE
BOILER EFFICIENCY		
BE1: Measuring Boiler Efficiency - How Often	10	10
BE2: Flue Gas Temperature, O2, CO Measurement	15	5
BE3: Controlling Boiler Excess Air	10	5
HEAT RECOVERY EQUIPMENT		
HR1: Boiler Heat Recovery Equipment	15	3
GENERATING DRY STEAM		
DS1: Checking Boiler Steam Quality	10	10
GENERAL BOILER OPERATION		
GB1: Automatic Boiler Blowdown Control	5	5
GB2: Frequency Of Boiler High/Low Level Alarms	10	10
GB3: Frequency Of Boiler Steam Pressure Fluctuations	5	5
BOILER PLANT OPERATING PRACTICES SCORE	80	53

<u>Slide 90:</u> We can see how we performed by each sub-topic.

Let's go back and see how we got that result. Click on Tab Number 5- SSOP – Boiler Plant

Begin SSST – Tab 5 – SSOP – Boiler Plant

Slide 91: Now, go down to 'Heat Recovery Equipment', near row 25.

HEAT RECOVERY EQUIPMENT

What To Do Evaluate installation of Heat Recovery Equipment on your Boiler Plant.

Why Important In some boilers, high flue gas temperatures and high continuous blowdown rates can provide opportunities for installation of heat recovery equipment. Feedwater economizers and combustion air preheaters can, under appropriate conditions, be installed to extract excess flue gas energy and effectively increase the boiler efficiency. Blowdown heat recovery equipment can also, for some systems, be installed to extract otherwise lost heat from the blowdown system. For either potential opportunity, an economic analysis is needed to determine the feasibility of the opportunity, and the equipment should be designed and installed by qualified professionals.

QUESTION NUMBER	QUESTION	ACTION	SCORE	YOUR SCORE
HR1	Do you have any of the following Heat Recovery Equipment installed on your Boilers?			
	Feedwater Economizer and/or Combustion Air Preheater	yes	10	
	Blowdown Heat Recovery	yes	5	3
		no to all of above	0	

Slide 93: We only scored 3 of 15 points. No points were scored for the Blowdown Heat Recovery.

QUESTION NUMBER	QUESTION	ACTION	SCORE	YOUR SCORE
HR1	Do you have any of the following Heat Recovery Equipment installed on your Boilers?			
	Feedwater Economizer and/or Combustion Air Preheater	yes	10	
	Blowdown Heat Recovery	yes	5	3
		no to all of above	0	

The Assessment Tool includes projects that will calculate the impacts associated with boiler blowdown thermal energy recovery. Project 5 and Project 12 install the two most common blowdown thermal energy recovery components—a flash tank and a heat exchanger.

Return to the Assessment Tool's 'Project Inputs'.

Return to SSAT – Project Inputs Tab

Slide 94: Cancel Project 13 by selecting 'No'.

Drop Down Menu selected

Project 13 - Condensate Recovery Currently recover 0% of HP, 70% of MP and 50% of LP at 180 F			
			Drop Down Menu:
			Yes
			No
Do you wish to specify new condensate recovery rates?			No
If yes, enter new HP condensate recovery	0	%	
If yes, enter new MP condensate recovery	70	%	
If yes, enter new LP condensate recovery	52	%	
Note: Condensate return temperature will be assumed to be 150 F as for the current operation			

Slide 96: Go to Project 5 – Blowdown Flash to LP.

Slide 98: Select 'Option 1- Install Blowdown Flash' from the pull-down menu.

Drop Down Menu selected

Project 5 - Blowdown Flash to LP Not currently installed	
	Drop-down Menu:
	Option 1 - Install blowdown flash
	Option 2 – No change
Do you wish to modify the blowdown flash system?	Option 1 - Install blowdown flash

No flash steam recovery was in-place in the base case.

Slide 99: Continue down to 'Project 12 – Feedwater Heat Recovery Exchanger using Boiler Blowdown'.

Slide 101: Select 'Yes – install a new heat exchanger'.

Drop Down Menu selected

Project 12 - Feedwater Heat Recovery Exchanger using Boiler Blowdown Not currently installed	
	Drop-down Menu:
	Yes, install a new heat exchanger
Modify the boiler blowdown heat recovery system?	Yes, install a new heat exchanger
Note: An approach temperature of 20 F will be assumed for a new exchanger	

No heat recovery exchanger was in-place in the base case.

Slide 103: Return to the 'Results' tab and once again you will note additional reductions in annual operating costs. Check the List of Projects and you will see both projects identified in this calculation scenario.

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	9,198	9,204	-6	-0.1%
Fuel Cost	33,575	32,854	721	2.1%
Make-Up Water Cost	361	343	18	5.0%
Total Cost (in $ '000s/yr)	**43,134**	**42,401**	**733**	**1.7%**

On-Site Emissions	Current Operation	After Projects	Reduction	
CO2 Emissions	390200 klb/yr	381824 klb/yr	8376 klb/yr	2.1%
SOx Emissions	0klb/yr	0 klb/yr	0 klb/yr	N/A
NOx Emissions	772 klb/yr	756 klb/yr	17 klb/yr	2.1%

Power Station Emissions	Reduction After Projects	Total Reduction	
CO2 Emissions	-136 klb/yr	8240 klb/yr	-
SOx Emissions	0 klb/yr	0 klb/yr	-
NOx Emissions	0 klb/yr	16 klb/yr	-

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

Utility Balance	Current Operation	After Projects	Reduction	
Power Generation	7513 kW	7503 kW	-	-
Power Import	15000 kW	15010 kW	-10 kW	-0.1%
Total Site Electrical Demand	22513 kW	22513 kW	-	-
Boiler Duty	383.4 MMBtu/h	375.1 MMBtu/h	8.2 MMBtu/h	2.1%
Fuel Type	Natural Gas	Natural Gas	-	-
Fuel Consumption	383278.3 s cu.ft/h	375051 s cu.ft/h	8227.3 s cu.ft/h	2.1%
Boiler Steam Flow	262.6 klb/h	257.0 klb/h	5.6 klb/h	2.1%
Fuel Cost (in $/MMBtu)	10.00	10.00	-	-
Power Cost (as $/MMBtu)	20.51	20.51	-	-
Make-Up Water Flow	16469 gal/h	15642 gal/h	827 gal/h	5.0%

Turbine Performance	Current Operation	After Projects	Marginal Steam Costs	
			(based on current operation)	
HP to LP steam rate	Not in use	Not in use		
HP to MP steam rate	22 kWh/klb	22 kWh/klb	HP ($/klb)	----->
MP to LP steam rate	28 kWh/klb	28 kWh/klb	MP ($/klb)	----->
HP to Condensing steam rate	Not in use	Not in use	LP ($/klb)	----->

Calculate Marginal Costs

Press this button if marginal costs are not shown

List of Selected Projects
Install blowdown flash to LP
Install blowdown heat exchanger
Increase LP condensate recovery

Gas Turbine Assessment	
Your site is a good candidate for the installation of a gas turbine + waste heat boiler	
Warnings - Any warnings listed below may impact on the validity of the simulation	
Current Operation	**After Projects**

Slide 105: As you can see, you can easily perform several stand-alone project simulations as well as scenarios of combinations of projects to identify the impacts in fuel, electricity, and water consumption, as well as emissions impacts. This will help you select the best project configuration to improve your steam system.

Slide 106: The Assessment Tool has many useful features to evaluate steam system improvement projects by assisting the user in selection of individual *[stand alone]* and combination of projects in order to better determine system-wide benefits from implementing these steam improvement projects *[including energy and fuel savings, cost savings, and emissions savings. A final projects list to consider for implementation can also be developed.]*

Slide 107: We can continue to return to the Steam System Scoping Tool (SSST) to identify other opportunities to evaluate with the Assessment Tool.

For example, Tab Number 4 - Total Steam System indicated 'Moderate' Steam Leaks. You can look at several ways to address this in the Assessment Tool. You can repair the leaks and thus reduce the steam demand on the system. Use 'Project 1 – Steam Demand Savings', the preferred method in most situations, to evaluate this opportunity. However, you can look at implementing a Preventive Maintenance Program under Project 17 – Steam Leaks, and let the model estimate a new steam leakage rate as an estimate of its impact.

QUESTION NUMBER	QUESTION	ACTIONS	SCORE	YOUR SCORE
LK1	How would you characterize Steam Leaks in your Steam System?	none	10	
		minor	8	
		moderate	3	3
		numerous	0	

There are many combinations and stand- alone projects to consider. The user can continue to 'tweak' the project list to identify the best possible solution for your system. Further study may be needed before implementation can occur, in particular for large capital investment projects, however there are many quick maintenance-type activities that can potentially have significant savings for a relatively low cost to implement.

You can also use your scorecard (the Scoping Tool) to track your progress in improving the management of your steam system and to continue your focus on areas that need improvement. For example, if you remember insulation was an area of the Scoping Tool that that did not receive excellent marks.

Slide 108: To begin a further look into potential projects for feasibility, let's look at the 3EPlus Insulation Thickness Computer Tool, or simply the Insulation Tool, or its acronym, 3EPlus. The Insulation Tool can help you further your investigation by evaluating insulation projects, from the standpoint of energy savings, cost savings, and economic feasibility.