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How to Calculate the True Cost of Steam

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Elie Tawil, P.E., LEED AP



Continuing Education and Development, Inc.

P: (877) 322-5800
info@cedengineering.ca

This course was adapted from the U.S. Department of Energy, Publication No. DOE/GO-102003-1736, “How to Calculate the True Cost of Steam”, which is in the public domain.

How To Calculate The True Cost of Steam

Knowing the correct cost of steam is important for many reasons, and all of them have to do with improving the company's bottom line, including:

- To properly evaluate the economics of proposed process efficiency or capacity-improvement projects; if the calculated cost is not accurate, many good energy projects may be missed or rejected, and bad projects may be approved for implementation
- To serve as a basis for optimizing the steam generation system, and minimize costs
- To ensure more effective negotiations with the utility or third party Independent Power Producers
- To properly evaluate proposed cogeneration projects.

Steam is used for a variety of applications in commerce and industry:

- Process heating
- Vacuum jets
- Shaft work for mechanical drives
- Power generation
- Space heating.

In industrial manufacturing facilities, process heating accounts for an average of more than 60% of thermal energy use, predominantly in the form of steam. Process heating also accounts for a significant portion of controllable operating costs. It is one of the few areas of opportunity where management can reduce operating costs and improve profits.

The True Cost of Steam

To determine the true cost of steam, we need to know more details about the steam in question. Are we discussing steam at the point of use? Steam at the point of generation? From which boiler? At what header pressure or at what quality? Average costs or marginal costs? If average costs, do they include both fixed and variable costs, or only the latter? Furthermore, we must distinguish between the cost of generation and the cost of consumption.

If the plant has only one steam generator (boiler), uses a single fuel, and has a single steam pressure level, it is relatively easy to assign a cost to the steam. However, in most cases, there are multiple steam sources and multiple fuels. There are also multiple steam pressure levels with multiple paths by which the steam pressure is reduced; for example, steam pressure can be reduced via pressure-reducing valves (PRVs) or turbines. Determining the true cost of steam then becomes far more complex. Several approaches have been tried, including the second law or "exergy analysis" method, the Nelson method, and the simulation modeling method. Of these, computerized simulation models are the most convenient, powerful, and reliable.

In most companies, the reported cost of steam is the average cost of generation at a particular production rate. The total operating costs—fuel, power, water, chemical additives, labor, maintenance, depreciation, interest, and administrative overheads—are divided by the total amount of steam produced. This may be a convenient corporate financial benchmark, but is not particularly useful for managing the steam system to minimize costs. For that, we need a better method for steam cost accounting.

One of the problems is that the cost of steam depends on the generation rate, especially in complex multi-boiler multi-fuel plants that also have steam turbines. To most people, this is not intuitively obvious. In this BestPractices Steam Technical Brief, we will show how to calculate the steam cost at different process operating rates, and demonstrate through an illustrative example that the only way to do this accurately is through steam-system modeling.

Consider the simplified system shown in Figure 1, taken from an actual plant.

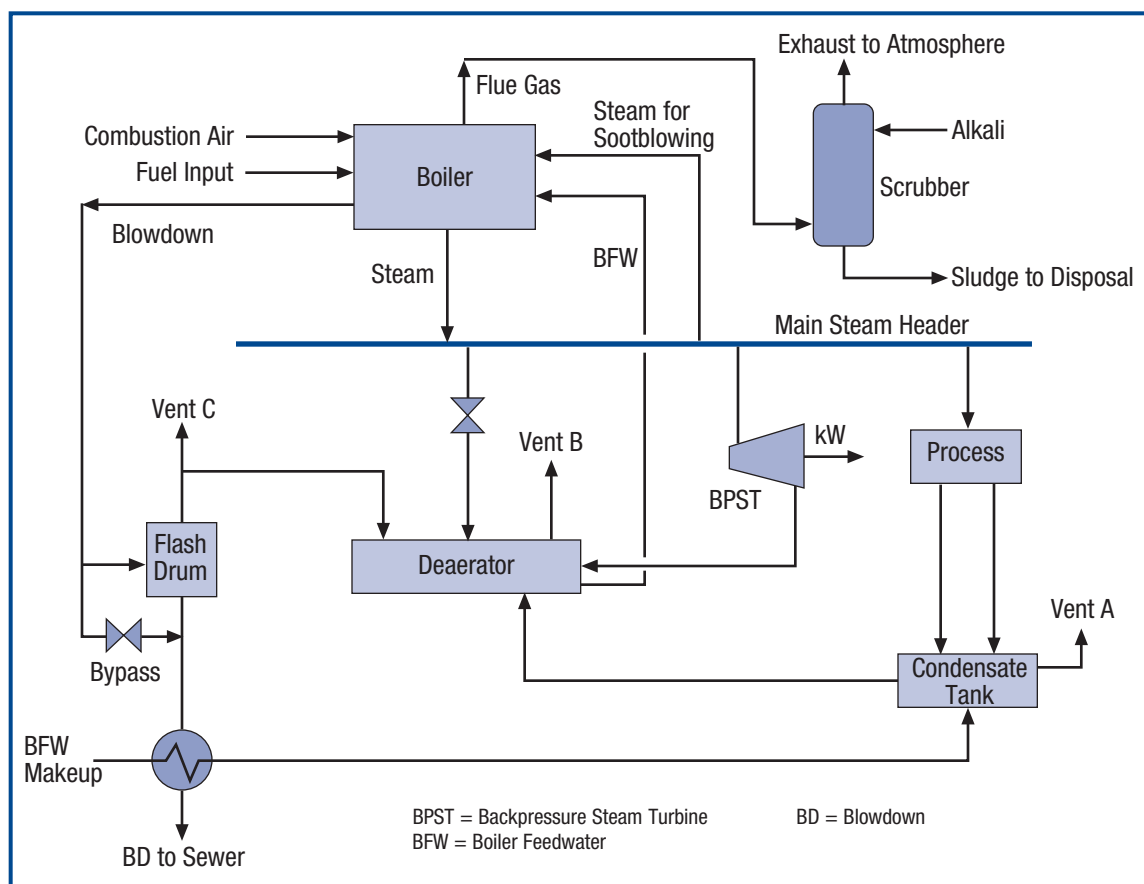


Figure 1. Typical Schematic Flowsheet for a Simple Steam System

In the following equations, the operating cost of the boiler is C_O per hour and the process requires S pounds/hour (lb/h) of steam. To deliver this much steam, it is necessary to actually generate $(1+X)S$ lb/h of steam, where X is a factor typically ranging from 5 to 20%. So we already have two distinct equations to determine the cost of steam:

- (a) generating cost C_G , \$/lb = $C_O/(1+X)S$
- (b) consumption cost C_G , \$/lb = C_O/S

Which cost equation should we use? We use the first equation when we are interested in making the generation system more efficient. We use the second one when we are interested in determining the true cost of process operation and when we are evaluating energy conservation projects.

Calculating the Cost of Steam Generation

The first step, which has several components, is to calculate the cost of generating steam from the boiler(s):

1. Fuel (C_F)
2. Raw water supply (C_W)

3. Boiler feed water treatment—including clarification, softening, demineralization (C_{BFW})
4. Feedwater pumping power (C_{P})
5. Combustion air fan (FD or ID) power (C_{A})
6. Sewer charges for boiler blowdown (C_{B})
7. Ash disposal (C_{D})
8. Environmental emissions control (C_{E})
9. Maintenance materials and labor (C_{M})

Calculating the cost of generating steam is relatively easy. The total variable cost of raising steam, C_{G} , is the sum of all these individual contributions, expressed as dollars per thousand pounds (\$/Klb) of steam generated:

$$C_{\text{G}} = C_{\text{F}} + C_{\text{W}} + C_{\text{BFW}} + C_{\text{P}} + C_{\text{A}} + C_{\text{B}} + C_{\text{D}} + C_{\text{E}} + C_{\text{M}}$$

Fuel cost is usually the dominant component, accounting for as much as 90% of the total. It is given by:

$$C_{\text{F}} = a_{\text{F}} \times (H_{\text{S}} - h_{\text{W}}) / 1000 / \eta_{\text{B}}$$

where a_{F} = fuel cost, (\$/MMBtu)
 H_{S} = enthalpy of steam, Btu/lb
 h_{W} = enthalpy of boiler feedwater, Btu/lb
 η_{B} = overall boiler efficiency, fractional.

Overall boiler efficiency is based on combustion air supply at ambient temperature, and boiler feedwater makeup temperature to the deaerator. It is assumed that boiler feedwater preheat from ambient to condensate temperature (usually about 200°F) will be done by heat exchange against a process stream, outside the boiler island battery limits, with only some “top-up” heat recovery against hot boiler blowdown. The use of steam to preheat boiler feedwater was common when energy was cheap, but using surplus process heat instead (from below the “process pinch” temperature) represents a significant opportunity for improved cycle efficiency. Overall boiler efficiency becomes primarily a function of the final flue gas temperature, and will typically be in the range of 80 to 85% when the excess air ratios are near optimal.

In principle, one should calculate the individual cost components rigorously for the site-specific conditions. In practice, it is usually sufficient to use an approximation:

$$C_{\text{G}} = C_{\text{F}} (1 + 0.30)$$

The number 0.30 represents a typical value for the sum of cost components 2 through 9 above (in oil- and gas-fired facilities). However, it could be more in smaller facilities, or in those that use coal and biomass. Normally, maintenance costs could be considered fixed, rather than variable. If the plant has multiple boilers, however, and there is an option to shut down one or more of them as the steam production rate is reduced, then maintenance costs should more properly be considered to be variable.

The second step is to calculate the cost of steam at lower pressure levels. This is not easy, as the cost depends upon the path that the steam follows from the point of generation to the point of use. Low-pressure steam that is produced through a pressure letdown station, usually a pressure-reducing valve (PRV), has substantially the same enthalpy as the higher-pressure steam from which it was made. Therefore, it will be superheated, and the normal practice is to desuperheat it using condensate. The low-pressure steam cost is then calculated from the high-pressure steam cost as:

$$C_{\text{L}} = C_{\text{H}} \times (H_{\text{SL}} - h_{\text{W}}) / (H_{\text{SH}} - h_{\text{W}})$$

where H_{SL} = enthalpy of low-pressure steam, Btu/lb
 H_{SH} = enthalpy of high-pressure steam, Btu/lb.

Making low-pressure steam through a PRV is inefficient. For steam flows over 50,000 lb/h, it is usually far more cost effective to extract by-product power by passing the steam through a backpressure steam turbine. When the low-pressure steam is produced through a turbine, its cost is calculated as:

$$C_L = C_H - 1000 \times a_E \times (H_{SH} - H_{SL}^*) / 3413 / \eta_T / \eta_G$$

where a_E = electrical power cost, \$/kWh

H_{SL}^* = enthalpy of low-pressure steam from isentropic expansion of high-pressure steam, Btu/lb

η_T = isentropic efficiency of steam turbine, fractional

η_G = generator efficiency, fractional.

The difficulty is to assign the correct cost to the increase or decrease in low-pressure steam consumption, which depends on the path followed by steam from the point of generation to the point of use (for example, PRV or turbine). The only way to determine the correct value is to develop a heat and material balance simulation model of the system.

Setting Up the Model

A simulation model is the mathematical representation of a physical process defined in terms of equations, constraints, and assumptions. The model must tie together the mass and energy interactions between the major subsystems—fuel system, boilers, steam turbines, gas turbines, deaerators, flash drums, desuperheaters, economizers, heat exchangers, and process steam users/sources.

The model accounts for the significant flows into and out of each subsystem, as well as for the boiler system as a whole. For the system shown in Figure 1, the inputs and outputs across the boiler-house boundaries are:

Inputs = Condensate return from process + boiler feedwater makeup

Outputs = Steam to process + blowdown from flash drum + vents to atmosphere (A, B, and C)

For material balance, neglecting losses, we set inputs = outputs (however, for many systems, losses can be significant and need to be tracked).

There are several internal subsystem balances that have to be satisfied as well.

For the boiler itself:

Steam generation + boiler blowdown (before flash) = boiler feedwater

For the steam header:

Steam generation = steam to process + steam to PRV + steam to turbogenerator + steam for soot blowing

For the condensate tank:

Deaerator feed = boiler feedwater makeup + combined process condensates – vent A

Boiler blowdown will be at the boiler temperature, and will flash when the boiler feedwater is let down to atmospheric condition. This flash vapor can be recovered for use in the deaerator. Normally, the blowdown is let down to the deaerator (DA) pressure, and the vent flow labeled “C” in Figure 1 is zero. Thus, for the blowdown flash drum, the balance is:

Blowdown from boiler = blowdown from drum + flash vapor to deaerator

For the deaerator,

Boiler feedwater = deaerator feed + steam to the deaerator from the PRV + steam to the deaerator from the turbine + blowdown flash vapor – vent B

In addition to the material balances, we must also develop the heat (enthalpy) balance equations for each subsystem. The combined set of equations is solved algebraically. Examination of the overall balance shows that there is one more unknown variable than there are equations, so it is necessary to solve the problem iteratively. This is not a problem, and the calculations tend to converge fairly rapidly in a unique solution. The recommended computational strategy is to assume a trial value of steam generation rate, and proceed to solve the equations for boiler feedwater makeup, condensate return, blowdown, and boiler feedwater.

The individual subsystem balances are then solved in a “top-down” sequence: steam header, blowdown flash drum, condensate tank and deaerator. The new calculated steam rate is then compared with the assumed trial rate, and this is repeated until the two values converge to within an acceptable difference.

The net cost of operating the system is equal to the cost of steam generation less the credit for power generation in the turbine.

For simple systems with steady steam demand, the calculation only needs to be done once, and then adjusted periodically when external circumstances or assumptions change. A computer-based model may not even be necessary.

Most large industrial steam systems are typically much more complex: with multiple boilers, multiple fuels, multiple pressure levels, and alternative connection paths (for example, PRVs and turbines) between the different steam headers, as in Figure 2. For them, it is particularly important that an accurate computer-based model is developed, and that the model is run frequently, perhaps as often as three times per day.

Methodology for Marginal Steam Pricing

Models can be configured to varying levels of detail. A model that is too simple may lack the discrimination to detect important effects. A model that is too detailed may be needlessly complicated and expensive to develop, without offering compensating value in terms of being a better decision-making tool. The sugar refinery example of Figure 2, which has seven boilers, four pressure levels, and three turbogenerators, represents the optimum level of detail for most industrial facilities, and provides acceptable results with only one iterative calculation loop.

The average steam generation cost can be calculated quite easily, but how can the consumption cost be calculated?

Before going further, we need to understand the distinction between average costs and marginal, or incremental, costs. The essential definitions are:

$$\text{Average Cost} = \frac{\text{Total Operating Cost}}{\text{Total Steam}} = \frac{Co}{S}$$

and

$$\text{Marginal Cost} = \frac{\text{Incremental Operating Cost}}{\text{Incremental Steam Consumption}} = \frac{\Delta Co}{\Delta S}$$

For evaluating energy conservation and/or efficiency improvement projects, it is the marginal cost that should be determined.

The first step is to decide on basic operating parameters for the combined heat and power system, including condensate return rate, boiler blowdown, deaerator pressure, fuel mix, condensate temperature, boiler feedwater makeup supply temp, the process steam demand profile, PRV, and steam turbine flows. The model is then used to calculate the total operating cost for this base case scenario, as in Table 1.

How does the total operating cost change if the consumption of low-pressure steam, at 12 pounds per square inch gauge (psig), in the process either increases or decreases by some amount, Y lb/h? To determine this, we manually change the input value of the low-pressure process steam consumption by the appropriate amount, and make a note of the new operating cost calculated by the model. However, the model should accurately incorporate the plant operating policy for fluctuations in the

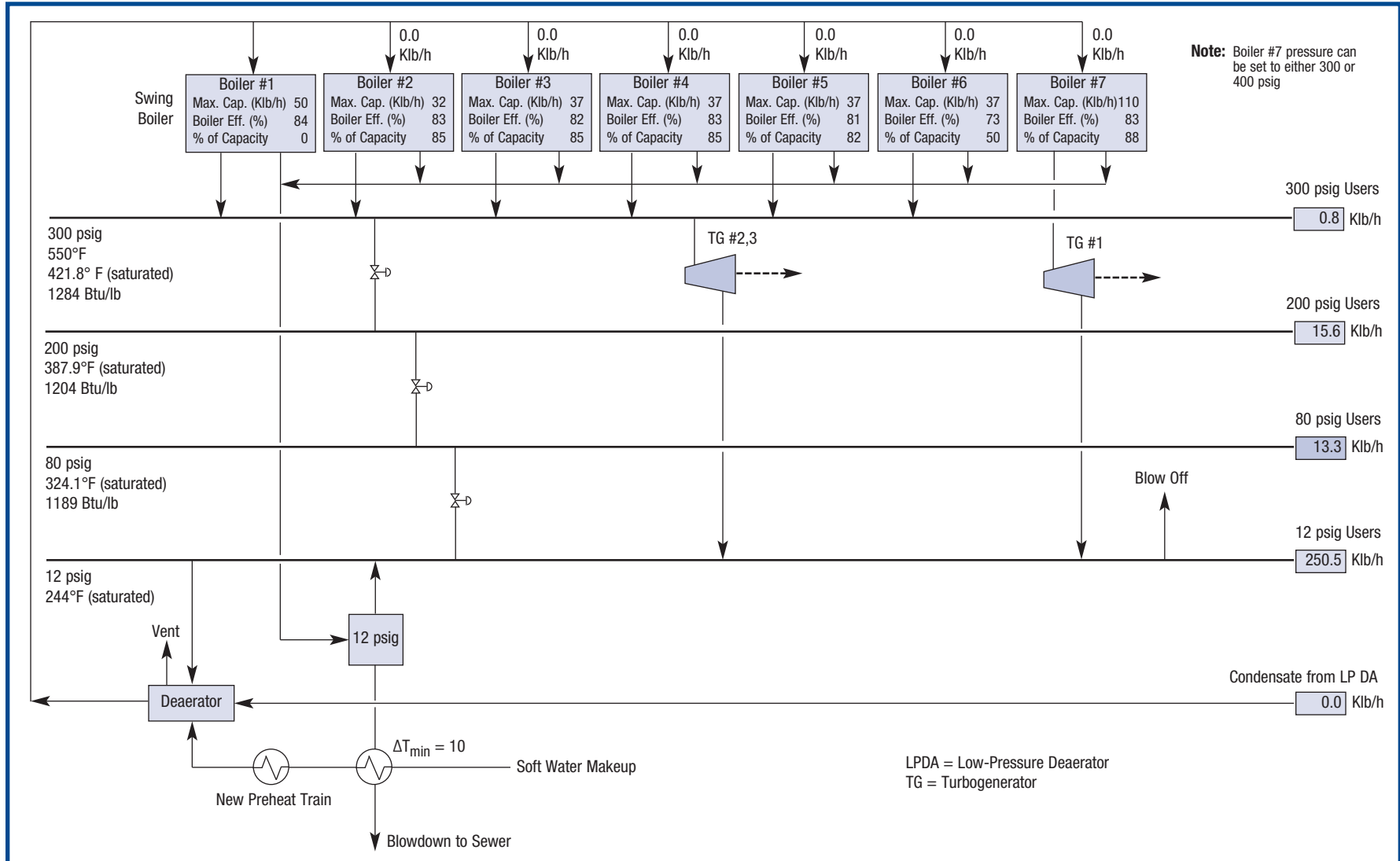


Figure 2. Simplified Schematic Flowsheet of Combined Heat and Power System for a Sugar Refinery

Table 1: Base-Case Steam Generation Costs from Model

Assumptions/Basis:

Required Power

Generated Power

Full Rate Operation

Total Boiler Duty

Gas Heating Value

8.32 MW

7.80 MW (includes direct mechanical drives)

7680 h/yr

370.8 MMBtu/h

1020 Btu/cubic foot

BD = Blowdown

ST = Steam Turbine

	Psig	Klb/h	Comments
Process Steam Demand	200	15.6	
	80	13.3	
	12	250.5	
Parasitic Steam Demand	300	1.7	Sootblowing and losses
	12	21.3	Deaerator
	12	-5.4	BD flash vapor recovery
Total Steam Generation Required:	300	297	

Operating Costs:

	Quantity	@	Unit	MM\$/yr
Gas (fuel)	363.6 KCF/h	2.40	KCF	6.70
Purchased Power	0.52 MW	61.0	MWH	0.24
Softened Water	246.4 gpm	1.00	Kgal	0.11
Wastewater	47.4 gpm	0.25	Kgal	0.01
			Total	7.06

Operating Policy and Constraints

1. Boilers #1 through 6, capacity limits:

Minimum = 30% of design

Preferred Rate = 85% of design

Maximum safe = 95% of design

2. Boiler #7 is operated independently of others; direct coupled to Steam Turbine #1 (steam demand for ST#1 depends on compressor load)

3. Steam flow capacity constraints on turbogenerators ST #2 and #3:

	Min	Max	
ST#2	20	60	Klb/h
ST#3	40	120	

process-steam demand. For example, important information includes whether the reduction in steam input to the low-pressure header is through a PRV or through a steam turbine, whether the required degree of superheat is being maintained, whether the correct boiler and fuel are being scaled back, whether the equipment capacity constraints are being observed, and whether the correct boiler and turbine efficiencies are being used at the new flow conditions.

This procedure is repeated for several additional perturbations, and the results are tabulated and illustrated in Table 2 and Figure 3.

Table 2 shows that the marginal cost of low-pressure steam varies significantly with operating rate, because the low-pressure steam follows different paths through the combined heat and power system. At the low end, when the process steam demand is 152.8 Klb/h, the gas boiler (#1) is being operated at its minimum rate (30% of capacity). Under these conditions, gas is the more expensive fuel, and the coal boilers (#2 through 6) are operated to provide the balance of steam demand. Turbogenerators #2 and #3 are at their minimum operating rates, 20 and 40 Klb/h respectively. As the process steam requirement increases the load on the coal boilers increases, as well as the amount of steam passed through turbogenerator #3 up to its maximum capacity of 110 Klb/h. As the steam demand increases, further, the flow through turbogenerator #2 starts to increase. At some point the preferred operating rate of 85% for the coal boilers is reached.

Further increases in steam demand must now be supplied from the gas boiler. Once the flow through turbogenerator #2 reaches its maximum capacity of 60 Klb/h, further demand for low-pressure steam can now only be provided by passing high-pressure steam through a PRV. The marginal cost of low-pressure steam therefore takes a dramatic rise. As low-pressure steam demand continues

Table 2: Results of Perturbation Analysis for Marginal Cost of Low-Pressure Steam

Steam, Klb/h Low-pressure to process	Op Rate, % of cap Coal Boilers	% of cap Boiler #1	Steam Flow, Klb/h Turbo-generator #2	Turbo-generator #3	PRV Flow Klb/h	Cost MM\$/yr	$\Delta(\text{Cost})$ MM\$/yr	$\Delta(\text{Low-pressure steam})$ Klb/h	Steam Cost \$/Klb
152.8	194	43	30	20	40	2.6	6.3	—	1.18
152.9									1.18
219.2	264	80	30	20	110	2.6	6.9	0.60	1.18
219.3									1.01
226.9	272	85	30	28	110	2.6	7.0	0.06	1.01
227.0									2.21
257.0	304	85	83	60	110	2.6	7.5	0.51	2.21
257.1									3.85
266.8	314	85	100	60	110	12.9	7.8	0.29	3.85
266.9									2.96
280.0	328	93	100	60	110	26.8	8.1	0.30	2.96

to increase, the maximum capacity of the gas-fired boiler is reached, and the coal-fired boilers need to be used, pushing them to their maximum safe operating limit of approximately 95%. Notice that the marginal fuel starts out as coal, then switches to gas, and then switches back to coal. The marginal low-pressure steam cost depends not only on the marginal fuel; it also depends on the path that the incremental steam flow follows between the point of generation and the point of use.

The results of Table 2 are plotted graphically in Figure 3, and show that the net steam cost is not constant. In fact, the net steam cost varies significantly with consumption rate, depending on the path being followed. The operating policy, as described above, is implicit in these curves. The same approach can be taken to determine the marginal cost curves for medium- and high-pressure steam.

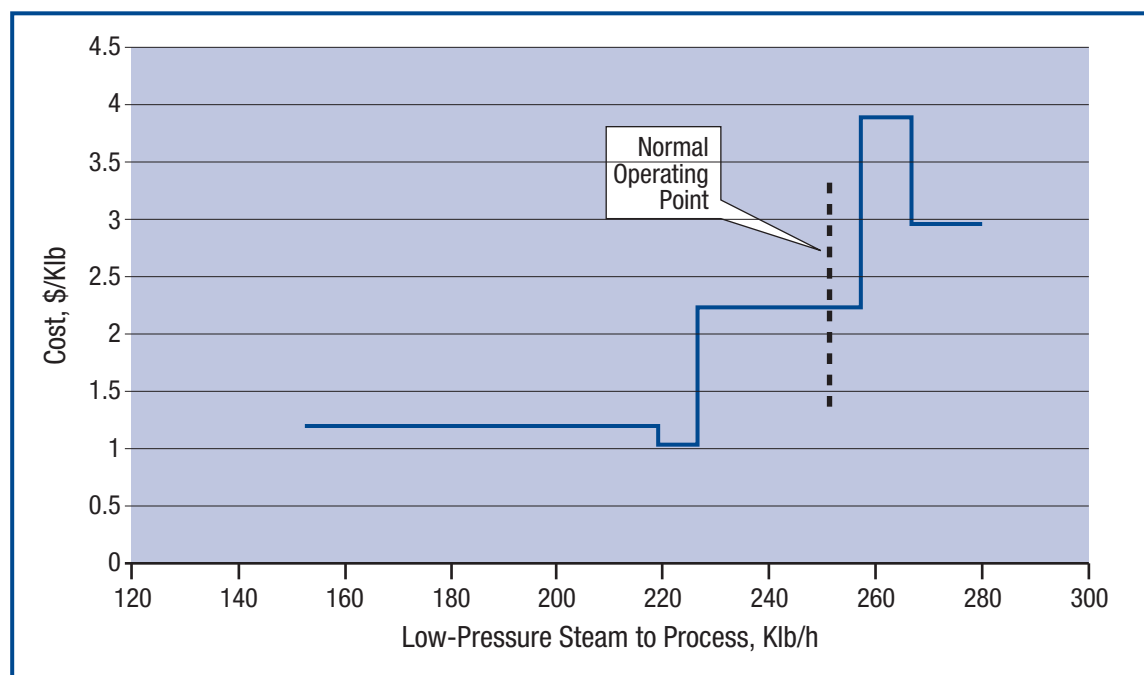


Figure 3. Variation of Net Low-Pressure Steam Cost (Marginal) with Consumption Rate
Illustrative Example for Evaluating a Proposed Energy Conservation Project

This example is for a proposed project to use the exhaust vapors from an evaporator as the heat source for the reboiler of a distillation column, as illustrated in Figure 4. Anticipated savings will be in 15-psig steam to the reboiler and cooling water load on the evaporator condenser, but the steam supply to the evaporator chest will have to be upgraded from 15 psig to 50 psig. The existing steam balance is shown in Figure 5. The plant operates 8,000 hours per year.

The combined heat and power system balance was calculated using a simulation model, which

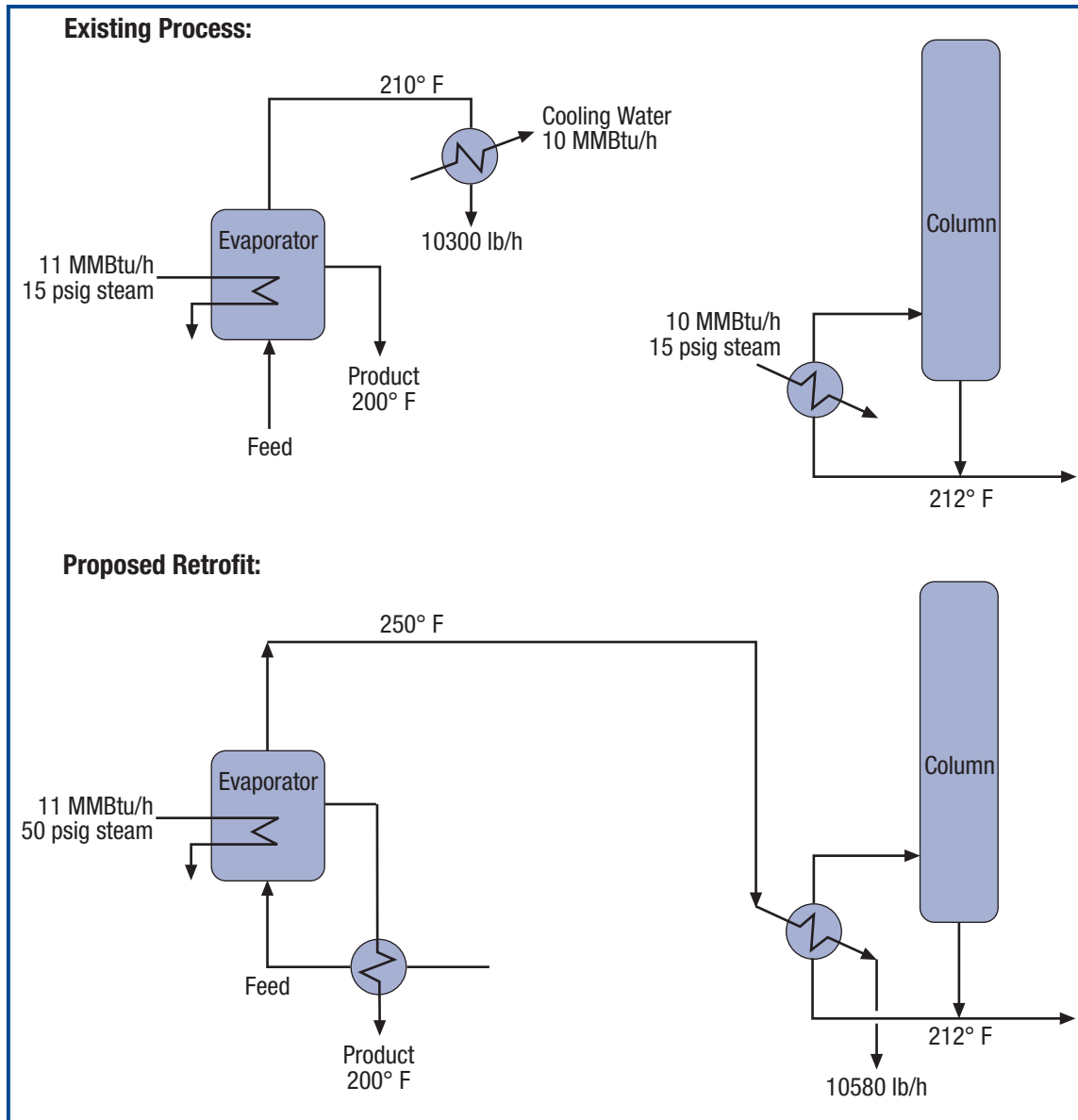


Figure 4. Flowsheet Schematic of Proposed Retrofit

also accounted for two significant operating constraints: a maximum turbine capacity is 50 Klb/h, and a minimum PRV flow rate is 5 Klb/h.

The process conditions, steam flow rates, and power generation in the steam turbine before and after project implementation are summarized in Table 3.

The results from using the conventional approach to pricing steam are illustrated in Table 4. The marginal cost of 200 psig saturated steam is taken to be its fuel value, calculated as:

$$1000 (H_S - h_W) a_F / \eta_B = \$3.00/\text{Klb}.$$

No value is assigned to condensate. Full credit for low-pressure steam is taken for cogenerated power.

In the base case, total steam use = 21 MMBtu/h at 15 psig = 22.2 Klb/h. In the proposed case, total steam use = 11 MMBtu/h at 50 psig = 12.1 Klb/h. The net project savings would then be computed to be:

$$\text{Savings} = (22.2 \times 1.00 - 12.1 \times 2.75) \times 8000 = -\$88,600 \text{ per year}$$

The project loses money because the loss of power credit exceeds the fuel savings. From this calculation, the project would clearly not appear to be beneficial.

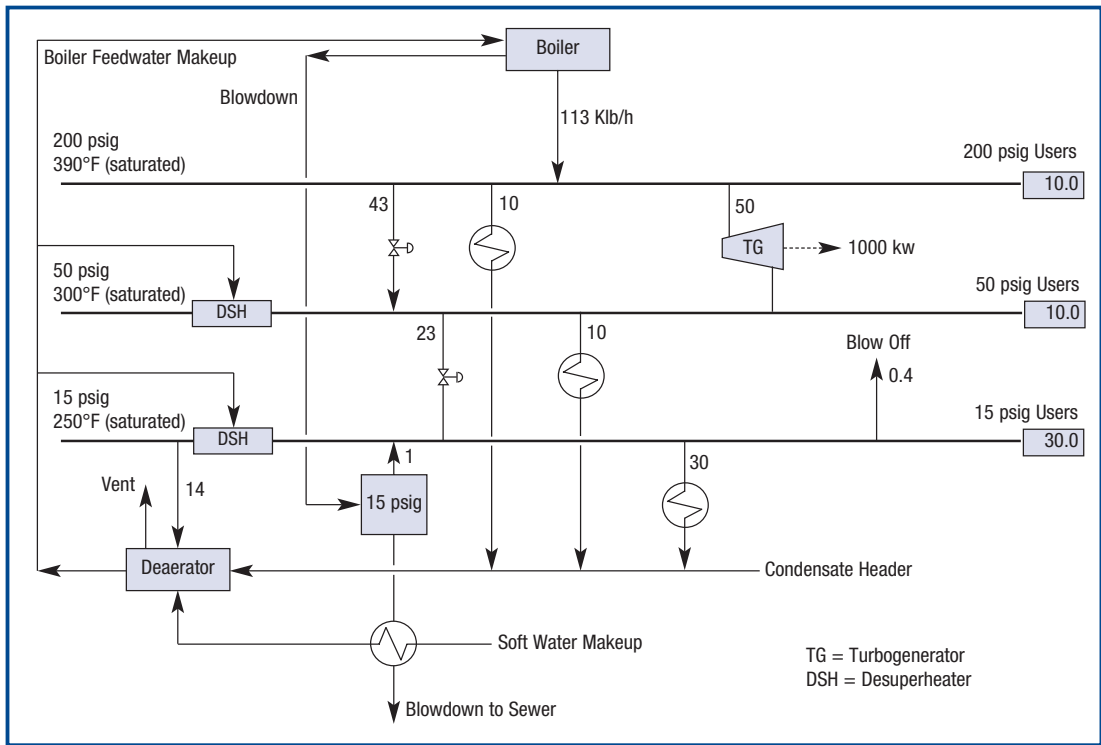


Figure 5. Combined Heat and Power System for Example Problem

Table 3: Summary of Key Project Parameters (from model)

		Existing	Proposed	Difference
Evaporator	Steam Pressure, psig	15	50	
	Steam λ_v , Btu/lb	945	910	
	Steam Flow, klb/h	11.64	12.09	455
Reboiler	Steam Pressure, psig	15	15	
	Steam λ_v , Btu/lb	945	945	
	Steam Flow, klb/h	10.58	0	-10.58
Combined Heat and Power System	Steam Generation in Boiler, klb/h	113.00	102.00	-11.00
	Condensate Return to Boiler, klb/h	60.00	49.90	-10.10
	Steam Flow thru 50/15 PRV, klb/h	18.00	5.00	-13.00
	Steam Flow thru Turbine, klb/h	50.00	40.00	-10.00
	Power Generated in Turbine, kW	2.00	1.60	-0.40
	Cooling Tower Duty, MMBtu/h	Q	Q-10	-10

Now consider the results from the recommended simulation modeling approach, with the affected utilities priced consistently, as follows:

Steam from boiler (at 200 psig)	= \$3.00 per Klb
Condensate return to boiler	= \$0.30 per Klb
Purchased electrical power	= \$0.05 per kWh
Cooling tower duty	= \$0.50 per MMBtu

The project economics are now calculated based on the material balance shown in Table 3:

$$\begin{aligned} \text{Net utility savings} &= \text{boiler fuel savings} - \text{reduced condensate credit} - \text{reduced power generation} \\ \text{credit} + \text{savings in cooling tower duty} &= (11 \times 3.00 - 10.1 \times 0.30 - 400 \times 0.05 + 10 \times 0.50) \times 8000 \\ &= \$120,000 \text{ per yr} \end{aligned}$$

Estimated capital cost = \$150,000
= 150/120

Simple payback = 1.25 years

From this calculation, the project would clearly appear to be beneficial.

Table 4: Steam Valuation by Conventional Method

	HP	MP	LP
Steam Pressure, psig	200	50	15
Superheat, °F	150	0	0
Total Enthalpy, Btu/lb Steam	1,288	1,180	1,164
Latent Heat, Btu/lb Steam	838	910	945
Desuperheater Water Added, lb/Klb Steam	0	90	0
Lb Steam per Klb High-Pressure Steam	1,000	1,090	1,000
Available Process Heat, Btu/Klb High-Pressure Steam	926,000	991,900	945,000
Fuel Cost, \$/Klb High-Pressure Steam	3.00	3.00	3.00
Steam Cost, \$/Klb Steam	3.00	2.75	3.00
Power Credit, \$/Klb Steam	0	0	2.00
Net Steam Cost, \$/Klb	3.00	2.75	1.00

Basis: Boiler produces 200 psig superheated steam
Lower-pressure steam is desuperheated using 250° F Boiler Feedwater

Why do the two calculating methods give such different answers? The reason is that the “simple” method does not properly account for the different paths followed by steam, whereas the “model” method does. Thus, the “model” method is the recommended approach.

Conclusion

Accurately determining steam costs is important for monitoring and managing energy use in a plant, for evaluating proposed design changes to the generation/distribution infrastructure and the process itself, and for continuing to identify competitive advantages through plant efficiency improvements. Steam costs are highly dependent on the path that steam follows in the generation and distribution system. Simulation models are simple, convenient, and reliable tools to follow these paths, calculate the correct costs, and to optimize the system.

The method used for evaluating utility costs has a dramatic effect on project economics, and therefore the investment decision. Improper utility pricing can lead to bad decisions; good projects can be discarded, and bad projects can be implemented. Regrettably, this is relatively common.

To avoid such mistakes, it is imperative that plant engineers and managers use appropriate methods for steam pricing, taking into account all the parameters that impact energy costs—fuel, condensate, power generation, and cooling water—when evaluating proposed projects.

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