Free Electricity From Steam Turbine-Generators:

A system-level economic analysis

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In district steam systems, back-pressure steam turbine-generators (BPTGs) can produce electricity without added fuel and often with well in excess of 100 percent fuel-to-electric efficiency. This process does not repeal the laws of physics, but rather capitalizes on the fact that much of the energy removed by a BPTG would otherwise be sent to the sewer as hot condensate.

In essence, BPTGs convert heat – heat that would otherwise be thrown away – into electricity. As a result, kilowatt-hours can be generated without marginal fuel purchase or combustion. This presents an opportunity both to district steam customers, who can use BPTG technology to reduce their electric costs with no marginal fuel expense or on-site emissions, and to district steam utilities themselves, which can either place BPTGs in their boiler houses or on their customers' premises to reduce electricity costs and atemperation expenses.

Using a New Approach

This approach marks a fundamental shift in evaluating BPTG economics. Earlier and more conventional approaches focused only on the portion of the steam system near the steam turbine. (For an excellent overview of the net efficiency of BPTGs using the conventional approach, see Ewing & DiTullio, "Using Small Steam Turbine Generator Sets to Replace Pressure-Reducing Valves," *Tappi Journal* 75:9, September 1992.) In conventional analyses, BPTGs were compared to pressure-reducing valves (PRVs) that would otherwise reduce high-pressure distribution steam down to process pressures. Since PRVs reduce steam pressure but not enthalpy, they exhaust superheated steam.

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By contrast, BPTGs remove enthalpy from the steam in the form of electricity, and therefore exhaust steam at a lower temperature than a PRV. Prior analyses assumed that the fuel-to-electric efficiency of BPTGs was the cost of replacing this heat, less any losses that occurred in the electric generator. Practically, the fuel-to-electric efficiency is the boiler efficiency multiplied by the generator efficiency: 75 percent to 85 percent. (This calculation, which will be detailed later, actually underestimates the actual efficiency observed in operating BPTG installations.) Even in this conservative assessment, however, BPTGs are easily the most efficient form of non-renewable power generation ever invented.

Figures 1 and 2 show a standard 'before' and a standard 'after' condition for a BPTG assessed under conventional methodology. The net effect of the BPTG in figure 2 is to increase the steam flow through the system. The reason for the increased flow at first seems to be fairly obvious: The thermal load requires 28.4 MMBtu/hr of heat, and the first law of thermodynamics dictates that energy removed as shaft power must no longer be present as heat. Therefore, steam flow is increased to make up for the heat energy that was converted into electricity. Right?

Well, sometimes. These figures make an implicit assumption that the condensate returned from the process must remain fixed – in this case, at 254 Btu/lb. Controls protocols, however, do not call for more steam as soon as the exhaust enthalpy falls below a set point – they call for more steam as soon as the *heat flux* to the thermal load falls.

However, slight reductions in supply-steam enthalpy do not necessarily reduce heat flux to the thermal load since good engineering practice is to oversize heat exchanger surface area. Furthermore, any heat exchanger designed to handle widely varying heat loads (in other words, any heat exchanger used for space heating) is by definition oversized for the majority of its operating hours. These practical considerations mean that a slight reduction in MMBtu/hour to a thermal load is usually irrelevant – with the heat exchanger oversized, slight reductions in inlet enthalpy simply reduce condensate temperature. Of course, the heat loss must be compensated for – financially and thermodynamically – if it translates into a reduction in boiler feedwater temperature. But there is no discernible increase in steam consumption after BPTG installation.

Following this argument, the logical next question is "do reductions in condensate temperature from process heat exchangers translate into reductions in boiler feedwater temperature?" In many cases, the answer is no: There truly is no marginal fuel consumption associated with the electric generation from a BPTG installation. Consider:

- In many condensate return systems, poor insulation in the condensate network – coupled with the temperature-dependence of radiative heat transfer – means that modest reductions in condensate temperature at the heat exchanger exit will not necessarily equate to reduced water temperatures at the boiler inlet.
- As district energy professionals are well aware, many municipal and campus steam systems are either too old or too large to justify the capital costs required to recover system condensate. In these systems, a reduction in condensate temperature simply leads to the rejection of colder water to the sewer.

Finally, note that in many municipal systems, BPTG electricity may actually be better than free. That is because the reduced condensate temperature will not only generate high-value electricity, but also will lead to a reduction in energy and water use and related costs required for atemperation.

Figure 1. *Partial System Energy Flows With a Pressure-Reducing Valve.*

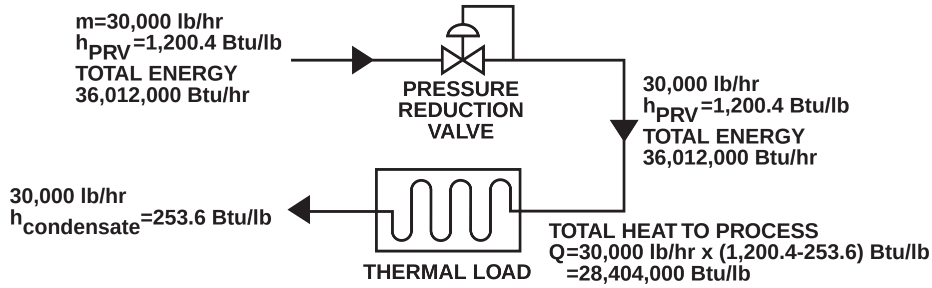
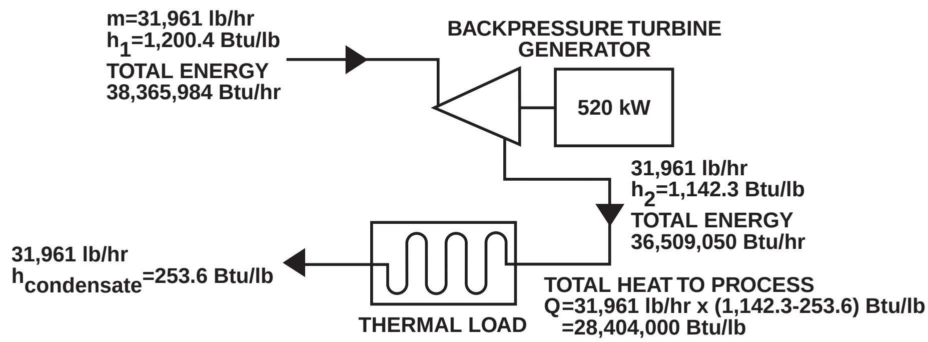


Figure 2. *Partial System Energy Flows With a Backpressure Steam Turbine (Simple Analysis)*



Source: Jim McCormick, Turbosteam Corp.

Calculating the Cost of Electricity

While many district energy systems have no condensate recovery, there also are many intermediate cases where some – but not all – of the condensate is returned to the boiler. Furthermore, while some heat exchangers may be sufficiently overdesigned to tolerate fairly large reductions in supply-steam temperature before additional steam flow is required, this is by no means universal. Thus, to estimate the cost of power from a potential BPTG installation, one must use the following sequential approach:

1. Calculate the enthalpy available at the exhaust of the BPTG, based on inlet- and exhaust-steam conditions and turbine isentropic efficiency.
2. Determine the minimum condensate temperature that will be tolerated by downstream heating systems without violating a 'pinch.'
3. Use the temperature calculated in (2) to define the condensate's enthalpy at the thermal load's outlet.
4. Use the enthalpy calculated in (1) and (3) to determine the amount of steam flow required to satisfy the thermal load. If this steam flow is in excess of current steam flow, the excess flow must be included in cost-of-electricity calculations. If this steam flow is less than the current steam flow, it implies that the reduced enthalpy available after BPTG installation at the current steam flow will not affect the thermal loads.
5. If there is no condensate-recovery system present, proceed to step (6). If there is a condensate-recovery system present, start by estimating the radiative heat losses in the system and determine whether or not the reduction in condensate temperature implied by the calculations in (3) is likely to lead to any reduction in boiler-inlet temperature. If there is no net impact, proceed to (6). Otherwise, calculate the additional enthalpy required to raise the feed water up to the original temperature and include this fuel use in the cost-of-electricity calculation (making sure to apply this only to the fraction of the condensate that is recovered.)
6. Add up the marginal fuel use determined in (4) and (5). Divide this fuel use by the anticipated kilowatt-hour production to calculate the cost of power generation.

Figures 3 and 4 provide an illustration of this methodology. These calculations use the same process specifications as the previous figures, but factor in assumptions that only 60 percent of the condensate is recovered and that process heat exchangers will not operate if the condensing steam temperature falls below 250 degrees F. (For the sake of simplification, this example assumes that there is no change in radiative heat losses after BPTG installation.)

In this example, the steam flowing through the turbine is only 30,750 lb/hr rather than the 31,961 lb/hr calculated under the simpler analysis methodology in figures 1 and 2 – in other words, the actual impact on boiler throughput is just 38 percent of the earlier estimate. Furthermore, 40 percent of this condensate is not recovered, meaning that only 60 percent of the reduction in condensate temperatures must be compensated for at the boiler.

Combining these impacts, it becomes apparent that the BPTG will lead to an increase in boiler heat output of just

$$38\% + 60\% \times (1 - 38\%) = 75.2\%$$

of the heat removed as energy at the turbine shaft.

The boiler has a marginal efficiency of 80 percent, and if the generator converts rotational energy into electricity at 96 percent efficiency, then the actual fuel-to-electric efficiency realized by the BPTG will be

$$(80\% \times 96\%) / 75.2\% = 102\%.$$

For every one unit of energy added to the boiler as purchased fuel, 1.02 units of electrical energy are generated from the generator! This sounds like a violation of thermodynamics, but it is not – it simply recognizes that some energy is always being thrown away. To the extent the net impact of a BPTG installation is to reduce the amount of energy being thrown away, any electricity that can be 'recycled' is free.

Creating Value

This presents an opportunity for cities like New York, Philadelphia, Boston, Detroit, Denver and San Francisco to buttress their congested urban electric transmission systems with fuel-free power. It also makes installation of hybrid BPTG/absorption chiller systems in these cities significantly more economical than has been assumed. This also represents opportunities in many process industries, which should re-examine past studies of BPTG opportunities with a corrected fuel-cost analysis. Finally, this analysis makes it imperative for regulators to recognize BPTG as a pollution-control strategy that pays dividends.

Installing BPTGs on the district energy company side of the meter will lead to reduced electricity costs and reduced atemperation expenses, all with little to no impact on marginal fuel consumption at the steam boiler. Installing BPTGs on the customer side of the meter will lead to the same reduction in atemperation expense for the district energy company and reduced electricity costs for the customer – both of which can create substantial value in today's uncertain energy rate environment.

Figure 3. *Steam system with less than 100 percent condensate return, pre-BPTG installation.*

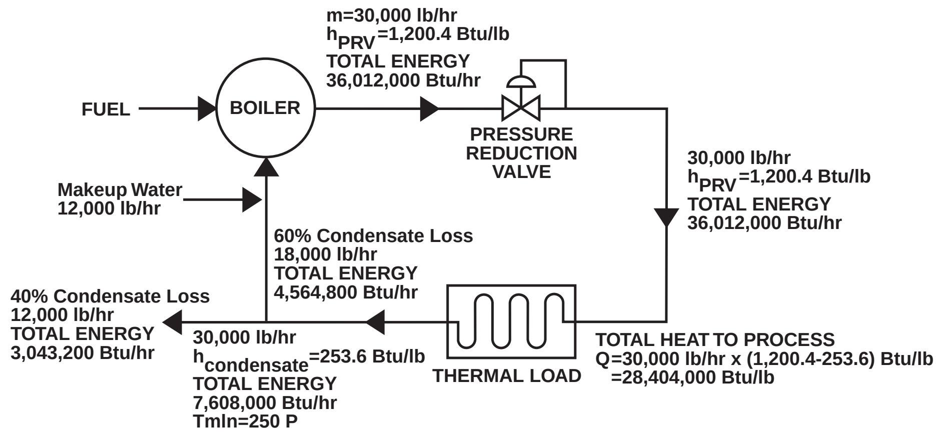
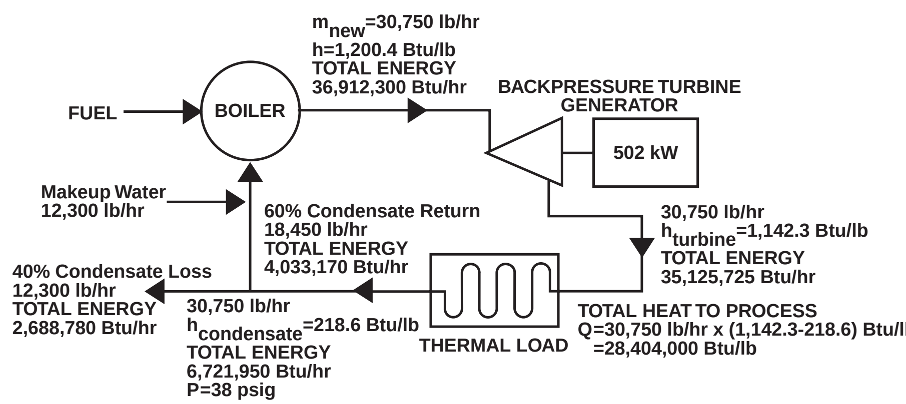


Figure 4. *Steam system with less than 100 percent condensate return, after BPTG installation.*



Source: Jim McCormick, Turbosteam Corp.

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