STEAM TURBINE
APPLICATIONS

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GRYPHON is a Canadian multi-discipline, full-service engineering design firm specializing in cogeneration, combined-cycle and thermal power plants and related equipment and systems, including level I, II and III feasibility studies, conceptual/schematic design, project development assistance, detail-design engineering, commissioning and startup, testing & project management.

STEAM TURBINE APPLICATIONS©

ABSTRACT

This paper describes how steam turbines can be applied into service for either:

a) electrical power generation, or
b) mechanical drive application,

considering both technical and simplified economic considerations.

For a starting point in the Electrical Power Generation section, a BASE CASE for a typical industrial facility is described, illustrating the plant's existing electrical power usage, steam production and fuel usage profiles, without cogeneration.

Sequential examples, with illustrations, extraction maps and simplified calculations are then given, showing how a steam turbine generator (STG) could be integrated into the Base Case* facility, to ultimately save money. The examples progressively increase in complexity, flexibility and cost, and decrease in overall efficiency, and include:

i) Backpressure STG
ii) Condensing STG
iii) Small Combined-Cycle Cogeneration Plant.

In the Mechanical Power Applications section, a simple cost-and-performance illustration of replacing electric motor driven boiler feedwater pumps and boiler FD fans, with mechanical-drive steam turbines is provided.

The paper finishes with a general discussion on steam piping, turbine auxiliaries and exhaust/condenser configurations.

* For an illustration of how a gas turbine generator could be integrated into the same Base Case facility, please refer to the Gas Turbine Applications© paper.
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1.0 ELECTRIC POWER GENERATION APPLICATIONS

Steam turbines are frequently combined with electrical generators to produce electrical power. When the exhaust steam and/or extraction steam from such a steam turbine is also used in a process application, we have produced two forms of useful energy from a single energy input, i.e. cogeneration.

To look at some of the ways that steam turbine generators can be applied in cogeneration service, we will examine the basic energy and economic parameters of a typical industrial facility to determine a reference BASE CASE and then expand it through several simplified potential cogeneration alternatives, including:

i) Alternative 1 - Backpressure Steam Turbine Generator
ii) Alternative 2 - Condensing Steam Turbine Generator
iii) Alternative 3 - Combined-Cycle Cogeneration Plant

1.1 Base Case

Referring to the enclosed BASE CASE graphic, the energy parameters of a typical industrial facility are shown.

The industrial facility purchases 25 MW of electricity from the local electrical utility during on-peak periods (4,000 hours per year, 2,000 hours in summer and 2,000 hours in winter) and off-peak periods (4,000 hours per year, 2,000 hours in summer and 2,000 hours in winter), for a total of 8,000 hours per year.

The facility's annual electrical purchase costs are $10.76 million per year, based upon the 1997 Ontario Hydro "Less than 115kV" rates, as follows:

<table>
<thead>
<tr>
<th>Ontario Hydro 1997 Rates for &quot;Less than 115kV&quot;</th>
<th>Demand</th>
<th>Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>On-Peak</td>
<td>13.81</td>
<td>4.63</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>-</td>
<td>3.42</td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>On-Peak</td>
<td>9.88</td>
<td>4.02</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>-</td>
<td>2.35</td>
</tr>
</tbody>
</table>

The overall annual-average electrical purchase rates for the facility are summarized as follows:

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Peak</td>
<td>7.9 €/kw.hr</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>2.9 €/kw.hr</td>
</tr>
<tr>
<td>Annual Average</td>
<td>5.4 €/kw.hr</td>
</tr>
</tbody>
</table>
The facility’s Steam & Boiler Plant provides 100,000 lb/hr of Process Steam for 8,000 hours per year, via pressure reducing valves and desuperheaters. The Steam Plant is fired with natural gas, and at a unit fuel cost of $3.25 per mmbtu\textsubscript{HHV}, the annual fuel costs are approximately:

\[
\text{Fuel Costs} = 126.0 \text{ mmbtu}_\text{HHV} \times 8,000 \text{ hr/yr} \times 3.25 \$/\text{mmbtu}_\text{HHV} \\
= $3.28 \text{ million per year}
\]

Thus, the total BASE CASE Utility Purchase Costs for the facility are:

\[
\text{Electricity} + \text{Fuel Costs} = $10.76 \text{ million} + $3.28 \text{ million} \\
= $14.04 \text{ million per year}
\]

For reference, the BASE CASE Heat to Power Ratio, during on-peak periods is:

\[
\text{H to P Ratio} = \left[\frac{100,000 \text{ lb}_\text{stm}/\text{hr} \times 1,008 \text{ btu/lb}_\text{stm}}{25,000 \text{ kW} \times 3,413 \text{ btu/kw.hr}}\right] \\
= \left[\frac{100.8 \text{ mmbtu}}{85.3 \text{ mmbtu}}\right] \\
\text{H to P Ratio} = 1.18
\]

The overall efficiency (HHV) of the Steam Plant is approximately:

\[
\text{Overall HHV} = \frac{\text{Heat Output}}{\text{Fuel Input}} \\
\text{Efficiency} = \frac{100.8 \text{ mmbtu}}{126.0 \text{ mmbtu}_\text{HHV}} \\
= 80\%
\]

* In the following examples, all financial costs are based upon an 80:20 debt/equity ratio for the indicated powerplant, with debt repayment conditions corresponding to a 15 year term loan obtained at 7.5% interest.
1.2 Alternative 1 –
Backpressure Steam Turbine Generator

Referring to the enclosed Alternative 1 graphic, a small and relatively inexpensive backpressure steam turbine generator is installed in the Steam Plant. This unit accepts the boiler’s 600 psig, 675 deg F outlet steam, expanding it and exhausting to the 125 psig header, thus bypassing the existing pressure reducing valves. A turbine exhaust desuperheater trims the turbine’s exhaust steam temperature to the desired Process Steam conditions. The total amount of Process Steam supplied is identical to the Base Case, but the backpressure STG set simultaneously produces about **3.1 MW** of electrical power.

Therefore, the facility electrical purchases decrease from 25.0 MW to \(25.0 - 3.09\) = 21.91 MW, and assuming the STG set operates for the same 8000 hours per year, the electrical purchase costs decrease to:

\[
\text{Electrical Costs} = 21,910 \text{ kW} \times 8,000 \text{ hrs/yr} \times 5.4 \text{ ¢/kw.hr} \\
= \$9.43 \text{ million per year}
\]

By comparing the Alternative 1 graphic to the Base Case graphic, we can see that more Steam Plant steam (as opposed to desuperheater spraywater) is required to make the same amount of Process Steam. This results in a slight increase in Steam Plant fuel requirements, from 126.0 mmBtuHHV to 139.2 mmBtuHHV. Thus, the fuel costs increase to:

\[
\text{Fuel Costs} = 139.2 \text{ mmBtuHHV} \times 8000 \text{ hrs/yr} \times 3.25 \text{ ¢/mmBtuHHV} \\
= \$3.62 \text{ million per year}
\]

Thus, the Alternative 1 total Utility Purchase Costs for the facility are decreased to:

\[
\text{Electricity} + \text{Fuel Costs} = \$9.43 \text{ million} + \$3.62 \text{ million} \\
= \$13.0 \text{ million per year}
\]

Compared to the Base Case total cost of $14.0 million/yr, this is a net decrease or potential savings of:

\[
\text{Potential Savings} = \$14.0 \text{ million} - \$13.0 \text{ million} \\
= \$1.0 \text{ million per year}
\]

Initially this appears to be a fair amount of savings, however, the Powerplant's debt payments and O&M costs will reduce these savings dramatically.

For a nominal plant cost of about $4.8 million, the annual Debt Payment will be about $0.4 million/yr. The annual O&M Costs will be about $0.1 million/yr.
The resultant Net Annual Savings are:

\[
\text{Net Annual Savings} = \text{Energy Savings} - \text{Finance Charge} - \text{O&M Cost}
\]

\[
= \$1.0 - \$0.4 - \$0.1
\]

\[
= \$0.5 \text{ million per year}
\]

The simplified Payback Period for this plant is about:

\[
\text{Payback Period} = \frac{\text{Capital Cost}}{\text{Net Annual Savings}}
\]

\[
= \frac{\$4.8 \text{ million}}{\$0.5 \text{ million}}
\]

\[
= 10 \text{ years}
\]

The Heat to Power ratio of the on-site Alternative 1 “cogeneration” equipment is:

\[
\text{H to P Ratio} = \frac{[100.8 \text{ mmbtuh}]}{[3090 \text{ kW} \times 3413 \text{ btu/kw.hr}]}
\]

\[
= 9.56
\]

which is not a very good match to the Base Case Heat to Power ratio of 1.18, and shows that a cycle with more power output is feasible.

In addition, by referring to the enclosed Alternative 1 STG performance map, it can be seen that with a straight backpressure steam turbine unit configured in this manner, the power output is always solely a function of the process steam requirement.

As a result, the STG unit's power output will vary with the facility’s need for process steam, and the STG will not be able to follow electrical load and cannot be used for management of facility peak demand purchases very well.

In summary, Alternative 1 demonstrates a relatively low cost method of displacing some purchased electrical power and decreasing the facility operating costs slightly.

It must be noted that the Steam Plant steam, fuel, make-up water facilities, etc. must be adequately sized, or updated to deliver sufficient amounts of steam.

In addition, in order to maintain the steam turbine at best efficiency, good steam and water treatment quality management is required.
1.3 ALTERNATIVE 2 – Condensing Steam Turbine Generator

Referring to the enclosed Alternative 2 graphic, a more expensive condensing steam turbine generator is installed to accept more Steam Plant output steam.

The inlet steam is expanded through the turbine high-pressure (HP) section and some steam is "extracted" at a controlled extraction port, providing the same amount of Process Steam (after trim desuperheating) as the Base Case.

The remainder of the steam is expanded through the low-pressure (LP) section of the steam turbine and is condensed and returned to the cycle.

Considerably more steam and fuel is required, and the Steam Plant systems will have to be adequately sized or uprated. Large amounts of cooling water will be required for a surface condenser.

The amount of power produced by the condensing STG is variable, depending upon the amount of extraction steam taken and the amount of condensing steam actually produced, as will be shown below.

The Alternative 2 graphic shows the cycle operating at 7.43 MW, i.e. more than double the output of the Alternative 1 backpressure unit.

Therefore, the facility electrical purchases decrease from 25.0 MW to [25.0 – 7.43] = 17.57 MW, and assuming the STG set operates for the same 8000 hours per year, the annual electrical costs decrease to approximately:

\[
\text{Electrical Costs} = 17,570 \text{ kW} \times 8,000 \text{ hrs/yr} \times 5.4 \text{ ¢/kw.hr} \\
= \$7.6 \text{ million per year}
\]

The additional “condensing” steam produced by the Steam Plant increases the fuel requirement to 193.5 mmbtuHHV and thus, the annual fuel costs increase to approximately:

\[
\text{Fuel Costs} = 193.5 \times 8000 \times \$3.25 \\
= \$5.0 \text{ million per year}
\]

Thus, the Alternative 2 total Utility Purchase Costs for the facility are further reduced to:

\[
\text{Electricity} + \text{Fuel Costs} = \$7.6 \text{ million} + \$5.0 \text{ million} \\
= \$12.6 \text{ million per year}
\]

Compared to the BASE CASE, this is a net decrease, or potential savings of:

\[
\text{Potential Savings} = \$14.0 \text{ million} - \$12.6 \text{ million} \\
= \$1.5 \text{ million per year}
\]
This is an improvement compared to Alternative 1, however, this is a much more expensive plant to build

For a nominal plant cost of about $9.0 million, the annual Debt Payment will be about $0.8 million/yr. The annual O&M Costs will be about $0.2 million/yr.

The resultant Net Annual Savings are:

\[
\text{Net Annual Savings} = \text{Energy Savings} - \text{Finance Charge} - \text{O&M Cost}
\]

\[
= 1.5 - 0.8 - 0.2 = \$0.5 \text{ million per year}
\]

The simplified Payback Period for this plant is about:

\[
\text{Payback} = \frac{\text{Capital Cost}}{\text{Net Annual Savings}}
\]

\[
= \frac{9.0 \text{ million}}{0.5 \text{ million}} = 18 \text{ years}
\]

Thus this Alternative 2 powerplant, while appearing to save more money, will actually have a longer payback and may not be as viable as Alternative 1.

The Heat to Power ratio of the on-site ALTERNATIVE 2 “cogeneration” equipment is:

\[
\text{H/P Ratio} = \frac{[100.8 \text{ mmbtuh}]}{[7430 \text{ kW} \times 3413 \text{ btu/kw.hr}]}
\]

\[
= 3.98
\]

which is a better match to the Base Case Heat to Power ratio of 1.18 than Alternative 1 was. However, if willing, there is still potential to make more electrical power.

To illustrate the comparative flexibility of a condensing STG, the Alternative 2 STG extraction map shows that, for instance, at an extraction flow of 100 kph, the STG power can be varied from about 5 MW to 10.5 MW, assuming sufficient steam can be provided from the Steam Plant.

Similarly, for example, at a desired load of 8 MW, the condensing STG can provide extraction steam in the range from zero to 125 kph.

In summary, Alternative 2 demonstrates a more expensive cycle capable of displacing more electrical power and of managing facility peak demand purchases, to decrease electrical purchase costs significantly.

As with the previous alternative, steam, fuel, feedwater, etc. facilities may require upgrading, and a condensing system is required.
1.4 ALTERNATIVE 3 – Combined Cycle Cogeneration Plant

Referring to the enclosed Alternative 3 graphic, a fairly expensive combined cycle cogeneration plant is shown, with a relatively small gas turbine generator (GTG), a fired heat recovery steam generator (HRSG), and a much larger, high pressure condensing steam turbine generator (STG). This is the same plant as shown in Alternate 4 in the Gas Turbine Applications© paper.

Because of the high steam pressure system shown, new feedwater, water treatment, etc. facilities will be required. The Steam Plant could potentially be retired.

The actual power output of the cycle and the total fuel required is dependent upon the amount of HRSG duct firing, the amount of extraction steam taken from the STG, and the amount of STG exhaust steam produced and condensed.

The total power output of the cycle at the operating condition shown is exactly 25 MW, thus decreasing the facility's Electrical Costs to zero.

The total amount of fuel for the GTG and the HRSG’s duct burner, at the typical operating point shown, is $157.5 + 117.5 = 275.0$ mmbtuh_HHV, for an approximate annual Fuel Cost of $7.15$ million per year.

Compared to the Base Case, the facility energy costs have been almost halved, and the Energy Savings are now approximately $6.9$ million per year.

For a plant Capital Cost of $23.5$ million (and an annual Debt Repayment of about $2.1$ million) and a $1.2$ million annual O&M Cost, the Net Annual Savings are approximately $3.6$ million per year, for a Payback Period of about 6.6 years.

For the operating point shown, the Efficiency of the Alternative 3 “cogeneration” equipment is about 68%, while the cycle perfectly matches the original Heat to Power Ratio of 1.18.

As depicted, this Alternative 3 can supply all the required Process Steam and all the required Electricity, with inherent flexibility to follow normal variations in each.

This Alternative 3 is relatively expensive, but still maintains good efficiency and a reasonable Payback Period.
1.5 Summary Comparison of Electric Power Generation Cases

The following table summarizes the Electric Power Generation cases:

<table>
<thead>
<tr>
<th>Alt.</th>
<th>Configuration</th>
<th>Eff’y %</th>
<th>Heat to Power Ratio</th>
<th>Cost ($mm)</th>
<th>Annual Opr’tng Cost * ($mm)</th>
<th>Annual Savings ($mm)</th>
<th>Simplified Payback Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>Boiler Plant + Utility Electricity</td>
<td>80% thermal</td>
<td>1.18</td>
<td>-</td>
<td>$14.0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>STG 1</td>
<td>Backpressure STG</td>
<td>80%</td>
<td>9.56</td>
<td>$4.8</td>
<td>13.0+0.5 ~ $13.5</td>
<td>$0.5</td>
<td>10 years</td>
</tr>
<tr>
<td>STG 2</td>
<td>Extraction - Condensing STG</td>
<td>65%</td>
<td>3.98</td>
<td>$9.0</td>
<td>12.6+1.0 ~ 13.6</td>
<td>$~0.5</td>
<td>18 years</td>
</tr>
<tr>
<td>STG 3</td>
<td>Small Combined Cycle Plant</td>
<td>68%</td>
<td>1.18</td>
<td>$23.5</td>
<td>7.1+3.3 ~ $10.4</td>
<td>$3.6</td>
<td>6.6 years</td>
</tr>
</tbody>
</table>

* Including fuel, electricity purchases/revenues, O&M and finance charges, as applicable.
STEAM TURBINE APPLICATIONS ©
Electric Power Generation Applications
The "BASE CASE"

Fuel Use - HHV
126.0 mmbtu/h

Steam
600 psig
675 deg F
89 kpph

Pressure Reducing Valves

Desuperheating Spray Water
11 kpph

Steam
125 psig
618 deg F
89 kpph

Desuperheater

Process Steam
125 psig
375 deg F
100 kpph
Heat to Process = 100,000 lb/hr x 1,008 btu/lb
= 100.8 mmbtu/h (net)

On-Site Energy Production
Heat Made: 100.8 mmbtu/h
Power Made: n/a mmbtu/h
Fuel Used: 126.0 mmbtu-HHV
Thermal Efficiency (steam): 80%

Facility BASE Heat to Power Ratio
100,000 lb/hr x 1,008 btu/lb
25,000 kw x 3,413 btu/kw.hr
= 1.18

27.6 kV
Transformer

13.8 kV Bus

Total Plant Loads:

<table>
<thead>
<tr>
<th>Total Plant Loads</th>
<th>Summer</th>
<th>Winter</th>
<th>Hrs*</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Peak MW</td>
<td>25.0</td>
<td>25.0</td>
<td>4000</td>
</tr>
<tr>
<td>Off-Peak MW</td>
<td>25.0</td>
<td>25.0</td>
<td>4000</td>
</tr>
</tbody>
</table>

* 50% summer, 50% winter

BASE CASE SCENARIO
An industrial facility utilizing ~ 25 MW of electrical power and 100,000 lb/hr of process steam, 8,000 hrs/yr.
The facility’s Steam & Boiler Plant produces superheated steam, which is reduced to the process steam pressure by
pressure reducing valves (PRV’S) and cooled to the process steam temperature by desuperheaters (DSH).
Power is purchased from the local electrical Utility. The Steam & Boiler Plant uses natural gas only.

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Sheet
1 of 4
STEAM TURBINE APPLICATIONS
Electric Power Generation Applications

ALTERNATIVE 1 - Backpressure Steam Turbine Generator

ALTERNATIVE 1 SCENARIO
All of the Steam Plant output steam is let down through a backpressure steam turbine, producing electricity. The turbine's exhaust steam is desuperheated to the target process steam temperature. Capital Cost about $4.8 million CAD.

Advantages
A "savings" of $1.0 mm/yr, compared to the Base Case. On-site thermal efficiency remains the same.

Disadvantages
**Annual finance ($0.4mm ) and O&M ($0.1mm ) costs reduce savings to about $0.5 mm Cdn /yr. Simple Payback is about $4.8 / $0.5 = 10 years.
Steam, fuel and makeup water, etc. requirements increase. Steam Plant facilities must be adequately sized, or uprated.
Power output is strictly a function of process steam demand, and inflexible for demand management.
Good water / steam treatment quality management required.
Increased plot plan requirements, near to the Steam Plant.
Backup Power Agreement required with electrical Utility.

<table>
<thead>
<tr>
<th>On-Site Energy Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Made: 100.8 mmbtu/h</td>
</tr>
<tr>
<td>Power Made: 10.6 mmbtu/h</td>
</tr>
<tr>
<td>Fuel Used: 139.2 mmbtu-HHV</td>
</tr>
<tr>
<td>Thermal Efficiency: 80%</td>
</tr>
<tr>
<td>Heat/Pwr Ratio: 9.56</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Utility Purchase Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler Fuel: $453 / hour</td>
</tr>
<tr>
<td>Fuel Cost: $3.62 / mmbtu</td>
</tr>
<tr>
<td>Elect Purch: 21.9 / MW-on</td>
</tr>
<tr>
<td>Elect Purch: 21.9 / MW-off</td>
</tr>
<tr>
<td>Elect Purch: 9.43 / mmbtu</td>
</tr>
<tr>
<td>Total Utility Cost / yr reduced to: $3.62 + $9.43 = $13.05 million</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Base Case minus Alt. 1:</th>
</tr>
</thead>
<tbody>
<tr>
<td>$14.04 - $13.05 = $1.0 million / yr</td>
</tr>
<tr>
<td>Potential savings for steam turbine investment purposes</td>
</tr>
</tbody>
</table>

** Finance and O&M costs to be paid from $1.0mm savings

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THROTTLE FLOW vs GENERATOR OUTPUT
BACK PRESSURE STEAM TURBINE
(STEAM TURBINE COGENERATION
APPLICATION 1)
600psig - 675°F - 125psig
**STEAM TURBINE APPLICATIONS ©**

Electric Power Generation Applications

**ALTERNATIVE 2 - Condensing Steam Turbine Generator**

![Diagram of steam turbine system]

**ALTERNATIVE 2 SCENARIO**

Steam is let down through a controlled extraction condensing steam turbine, producing electricity. Extraction steam pressure is set by turbine’s extraction control valve, and desuperheated to the target process steam temperature. LP turbine exhaust steam is condensed. Capital Cost about $9.0 million CAD.

**Advantages**

- A Utility "savings of about $1.5 mm/yr.
- Net operating costs decreased.
- Cycle is flexible, to follow the plant electrical/steam load, and/or manage plant electrical demand, by varying the firing and thus condensing steam.

**Disadvantages**

- **The annual finance charger (0.8mm ) and O&M cost (0.2mm ) reduce savings to about 0.5 mm/yr.
- Simple payback period about of 9.0 / 0.5 = 18 years
- On-site thermal efficiency decreases slightly.
- Steam Plant facilities must be adequately rated for increased steam, fuel and makeup water requirements.
- Cooling water or other condensing means required.
- Good water / steam treatment quality management required.
- Increased plot plan requirements.
- Backup Power Agreement required with electrical Utility.

<table>
<thead>
<tr>
<th>On-Site Energy Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat: 100.8 mmbtu/h</td>
</tr>
<tr>
<td>Power: 25.4 mmbtu/h</td>
</tr>
<tr>
<td>Fuel: 193.5 mmmbtu-HHV</td>
</tr>
<tr>
<td>Thermal Efficiency: 65%</td>
</tr>
<tr>
<td>Heat/Powerratio: 3.98</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Facility Utility Purchase Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Cost: $629 per hour</td>
</tr>
<tr>
<td>Fuel Cost: $5.0 million / yr</td>
</tr>
<tr>
<td>Elect Puch: 17.6 MW-on peak</td>
</tr>
<tr>
<td>Elect Puch: 17.6 MW-off peak</td>
</tr>
<tr>
<td>Elect Puch: $7.6 million / yr</td>
</tr>
</tbody>
</table>

Total Utility Cost / yr reduced to: $5.0 + $8.1 = $12.6 million

<table>
<thead>
<tr>
<th>Simplified Investment Potential**</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case minus Alt. 2:</td>
</tr>
<tr>
<td>$14.0 - $12.6 = $1.5 million / yr</td>
</tr>
<tr>
<td>Potential savings for steam turbine investment purposes</td>
</tr>
</tbody>
</table>

** Finance and O&M costs to be paid from $1.4mm savings

Prepared by:
Gryphon International Engineering Services Inc.
THROTTLE FLOW vs GENERATOR OUTPUT
CONDENSING STEAM TURBINE
(STEAM TURBINE COGENERATION APPLICATION 2)
600psig - 675°F - 1.5 IN HG
AUTO EXTRACTION AT 125psig
STEAM TURBINE APPLICATIONS

Electric Power Generation Applications

Alternative 3 - Small Combined Cycle Cogeneration Plant

<table>
<thead>
<tr>
<th>Fuel HHV</th>
<th>157.5 mmbtu/h</th>
<th>117.5 mmbtu/h</th>
<th>Process Steam</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen MW 12.6</td>
<td>GT Compressor</td>
<td>GT Turbine</td>
<td>Heat Recovery Steam Generator</td>
</tr>
<tr>
<td>43 mmbtu/h</td>
<td>375 deg F</td>
<td>100 kpph</td>
<td>100.8 mmbtu/h (net)</td>
</tr>
</tbody>
</table>

On-Site Energy Production

- Heat: 100.8 mmbtu/h
- Power: 86.3 mmbtu/h
- Fuel: 275.0 mmbtu-HHV
- Thermal Efficiency: 68%
- Heat/Power Ratio: 1.18

Self-generated Electricity Cost: 3.6 c/kW.hr

ALTERNATIVE 3 SCENARIO

A small combined cycle plant, including a GTG, a high pressure fired HRSG and an extraction-condensing STG. The combined power output could displace most of the purchased power (25 MW shown).

An extraction on the steam turbine provides the required process steam. Capital Cost about $23.5 million CAD.

Advantages

- A nominal "savings" fo $6.9 mm/yr, compared to the Base Case.
- On-site operating efficiency good. Cycle is flexible to follow electrical & steam load, by varying duct firing.

Disadvantages

- The annual finance ($2.1mm) and O&M ($1.2mm) costs reduce savings to about $3.6 mm/yr.
- Simple payback about $23.5 / $3.6 = 6.6 years.
- Increased plot plan requirements. Cooling water or other condensing means required.
- Backup Power Agreement required with electrical Utility.

Facility Utility Purchase Costs

- Fuel Cost: $894 per hour
- Fuel Cost: $7.15 million/yr
- Elect Purch: 0.00 MW-on peak
- Elect Purch: 0.00 MW-off peak
- Elect Purch: 0.00 million/yr
- Total Utility Cost per year $7.15 + $0.0 = $7.15 million

Condenser Cooling Water 7800 USgpm

Simplified Investment Potential **

- Base Case minus Alt. 4: $14.05 - $7.15 = $6.9 million/yr
- Potential savings for combined cycle investment purposes

** Finance and O&M costs to be paid from $6.9mm savings

Prepared by:
Gryphon International Engineering Services Inc.
THROTTLE FLOW vs GENERATOR OUTPUT

CONDENSING STEAM TURBINE
(STEAM TURBINE COGENERATION APPLICATION 3)
900psig – 900°F – 1.5 IN HG
AUTO EXTRACTION AT 125psig
2.0 MECHANICAL POWER APPLICATIONS

Small steam turbine sets are quite often used in mechanical power applications to drive boiler feedwater, cooling water or oil pumps, gas or air compressors and/or air handling fans.

Such steam turbines are usually rugged single-stage or two-stage machines, with simplified controls and auxiliaries. They can potentially be operated as variable speed drives, offering operating system flexibility benefits and lowered operating costs similar to the benefits of variable frequency electric motor drives.

In a steam plant, these smaller steam turbines are usually backpressure units, and may exhaust to a Process Steam header or to the Steam Plant deaerator.

Larger steam turbine sets, in various configurations including condensing, extraction/condensing, and/or backpressure mode, are frequently employed as an integral component of the production process in larger refineries and petrochemical complexes, etc. to drive large compressors and pumps.

These larger steam turbine units are usually designed to rugged API standards, to operate at varying speeds as dictated by the process demands upon the driven equipment. These units are not covered in the following examples, but their application is very similar to that covered in Section 1.0 above.

To look at how mechanical drive steam turbines can be applied in cogeneration service, we will examine the same BASE CASE as discussed in the above Section 1.0, but concentrate upon replacing some of the smaller Steam Plant services therein.
2.1 **Base Case**

Referring to the enclosed BASE CASE graphic, we look now at the Steam Plant's boiler feedwater pump drives and the boiler forced draft fan drives.

The boiler feedwater pump supplies the feedwater for the boilers and also the spraywater for the desuperheaters and is driven by a 150 hp motor, requiring about 102 kW to operate at the given BASE CASE conditions.

The boiler forced draft fan(s) are driven by a 75 hp motor, and require about 47 kW to operate at the given BASE CASE conditions.

The hourly cost of electricity to operate the pump and fan drives is approximately:

\[
\text{Electrical Costs} = [102.4 + 46.7] \text{ kW} \times 5.5 \text{ ¢/kw.hr} \\
= \$8.20/\text{hour}
\]

The BASE CASE cost of fuel for the facility is approximately $409.64/hour.

Thus, the total applicable Utility Purchase Costs are approximately:

\[
\text{Electrical + Fuel Costs} = \$409.64/\text{hr} + \$8.20/\text{hr}
\]

\[
= \$417.84/\text{hour}
\]
2.2 **ALTERNATIVE 1 – Backpressure Steam Turbines**

Referring to the enclosed Alternative 1 graphic, both of the electric motor drives can be supplemented by **backpressure steam turbine drives**, exhausting to the Process Steam header.

When operating these drives with the steam turbines, the applicable **Electrical Purchase costs** decrease to **zero**.

The amount of steam production required increases slightly, while spraywater requirements decrease slightly. The increased steam requirement results in a slight **increase in Fuel Costs**, from approximately $410/hour to **$412/hour**, as shown.

The net applicable **Utility Purchase Costs** are then **$411.71/hour**. If the backpressure steam turbines are operated for **8000 hours per year**, the annual savings would be approximately:

\[
\text{Potential Savings} = (417.84/hr - 411.71/hr) \times 8000 \text{ hrs/year} = 6.13 \times 8,000 = $49,040 \text{ per year}
\]

These net annual "potential" savings could be applied to the backpressure steam turbine investment.
**Typical Existing Scenario**

A steam plant produces high pressure, superheated steam which is reduced to process steam temperature and pressure. The boiler feedwater pump supplies both the boiler water and the spray water, and is driven by a 150 HP electric motor. The forced draft fan supplies air to the boiler for combustion purposes. This example can be made with other plant equipment such as air compressors, etc.
STEAM TURBINE APPLICATIONS ©

MECHANICAL POWER APPLICATIONS
Alternative 1 - Backpressure Steam Turbines

Alternative 1 Scenario
The boiler feedwater pump electric motor and the forced draft fan electric motor are supplemented with backpressure steam turbines.

Advantages
- Turbines offer a net annual savings.
- Relatively low installation costs.

Disadvantages
- Additional piping requirements.
- Electric motor driven equipment required for startup.

Applicable Energy Summary
Heat Made: 100.8 mmBtu/h
Fuel Used: 126.7 mmBtu/h

Applicable Utility Purchase Costs
Fuel Cost: $411.71 per hour
Elect Purch: 0.0 kw
Elect Purch: $0.00 per hour
Total Applicable Utility Purchase Cost
$411.71 + $0.00 = $411.71 / hour

Net Utility Savings per year
[$417.84 - $411.71] x 8,000 hrs/yr = $49,040 per year
ALTERNATIVE 1
3.0 TURBINE INLET, EXTRACTION/ADMISSION
AND EXHAUST PIPING CONSIDERATIONS

In order to maximize the power production from any steam turbine, the piping should be sized to economically minimize operating pressure drop. The general rules of thumb for maximum steam velocity in steam turbine piping applications are as follows:

a) Inlet - 175 feet/second
b) Extraction - 250 feet/second
c) Admission - 175 feet/second
d) Exhaust - 250 feet/second

Even more important for achieving maximum steam turbine power and efficiency is maintaining the proper inlet steam temperature. For most high inlet pressure steam turbines, each one (1) degree F variation from the design inlet temperature has an effect which is 5 times relatively greater than a one (1) psig variation from design inlet pressure. Thus, it is important to insulate turbine inlet steam piping more than normally required for personnel protection, to maintain the highest inlet steam temperature.

All steam piping must always be designed (materials and wall thickness) in accordance with the proper piping code, but it is important to note that extraction steam piping and/or exhaust (for backpressure turbines) steam piping may operate at significantly higher temperatures than nominal, approaching the inlet steam temperature themselves at low steam turbine loads.

All piping must be designed and adequately supported so that no undue forces and moments are exerted upon the turbine and its nozzles during start-up or operation. High piping loads could cause damage to the turbine and/or supports, could cause misalignment and vibration, or cause casing steam leaks or blade rubs.

All piping must be fitted with automatic drain valves and steam traps to ensure that all condensate is drained prior to start-up and during normal operation and shutdown.

Inlet steam piping should include isolation gate valve(s) to ensure positive isolation of the turbine during shutdown, flow metering equipment and steam sampling nozzles to allow performance condition monitoring. The steam turbine vendor will provide a trip and throttle valve (TTV) or stop valve, which is designed to close quickly in the event of an emergency trip, to prevent admittance of any further steam which might cause overspeed.
Extraction steam piping should include not only isolation gate valve(s), but also power operated extraction non-return valve(s), supplied by the steam turbine vendor. These valves should close automatically in the event of an emergency trip to prevent admittance of steam which could cause overspeeds and close automatically upon detection of condensate in the extraction piping, or leak detection in a feedwater heater (where applicable), to prevent the steam turbine from dangerously ingesting water. The extraction piping should include extraction relief valves to prevent accidental overpressurization of the turbine low-pressure section in the event of failures of the turbine extraction control valves. Extraction piping should include flow metering equipment. Where required by the design of downstream equipment, desuperheaters (for controlled extraction), or steam conditioning valves (for uncontrolled extractions) may be required in the extraction outlet piping to regulate the steam temperatures.

Admission steam piping should include not only isolation gate valve(s) but an admission stop valve, supplied by the steam turbine vendor. Admission piping should include flow metering and steam sampling nozzles, to allow performance condition monitoring.

In the case of backpressure steam turbines, the exhaust steam piping should include relief valves, isolation gate valve(s) and flow metering equipment.

In the case of condensing steam turbines, the exhaust should include a bursting disc, which relieves the exhaust and condenser space in the event of a failure of the vacuum raising system or condenser cooling water system or steam leakage into the unit during shutdown from leaking isolation valves. This bursting disc is usually supplied by the steam turbine vendor and is set to open several psi above atmospheric pressure. It is also frequently advantageous to install a vacuum breaker valve (VBV) on the steam turbine's exhaust hood or in the condenser vacuum space. This VBV can be arranged to allow air to enter the exhaust space on an emergency or controlled shutdown, to decrease the roll-down time dramatically. The VBV is usually interlocked with a permissible turbine speed, to ensure that it is not opened too early, which might overstress turbine blading. The VBV inlet is usually protected by a screen to prevent ingress of foreign material during operation, and water sealed to ensure that no air could leak into the condensing system during normal operation.

In order to maintain steam turbine reliability and efficiency and to prevent deposition, erosion and/or corrosion, stress corrosion cracking, etc. of a steam turbine’s bladepath, internals and valveworks, the inlet steam quality must be strictly maintained. This requires not only a good and well operated water
treatment system, but good steam separation equipment in the boiler and/or heat recovery steam generator drums. All turbine vendors supply recommended inlet steam start-up and continuous operation purity limits, generally as follows (for high pressure steam turbines):

<table>
<thead>
<tr>
<th></th>
<th>Continuous</th>
<th>Start-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductivity</td>
<td>0.3</td>
<td>1.0</td>
</tr>
<tr>
<td>SiO</td>
<td>20</td>
<td>50</td>
</tr>
<tr>
<td>Fe</td>
<td>20</td>
<td>50</td>
</tr>
<tr>
<td>Cu</td>
<td>3</td>
<td>10</td>
</tr>
<tr>
<td>Na + K</td>
<td>20</td>
<td>20</td>
</tr>
</tbody>
</table>

Steam turbine vendors generally design their bladepath and casing materials for the Owner’s indicated normal design conditions, but realize that these steam conditions cannot always be maintained strictly. They will allow limited overpressure and overtemperature operation, generally as follows (refer to each vendor for individual details):

i) Overpressure:
   - 12-month average – no more than 105% of design pressure
   - Do not exceed beyond 105% for more than 12 hours per year
   - Do not exceed 110% in maintaining these averages

ii) Overtemperature:
   - 12-month average – no more than the design temperature
   - 400 hours/year maximum – up to 25 deg F over design temperature
   - 15 minute maximum – up to 50 deg F over design temperature

Never exceed 50 deg F over design temperature.
4.0  **TURBINE EXHAUST and CONDENSER CONSIDERATIONS**

Backpressure steam turbines are generally available with top, bottom or side exhausts, with no fundamental efficiency differences between them. The best choice is generally a function of the particular site requirements.

Most vendors have several possible exhaust configurations for their condensing steam turbines. Site requirements, such as available physical space and the type of condensing means (water-cooled vs. air-cooled) to be employed, may dictate the best choice for each particular installation:

i)  **Bottom (Down) Exhaust:**
- the classic application for water-cooled condensing applications
- requires an elevated (tabletop) foundation for the steam turbine, with the condenser located underneath the unit, between the legs
- the condenser can be solid mounted (with an expansion joint) or spring mounted (with a solid transition piece)
- difficult, but not impossible, to adapt to air-cooled condensing systems

ii) **Top or Side (Perpendicular) Exhaust:**
- allows the unit to be placed upon a low “monolithic” block foundation, which is potentially less expensive than the tabletop foundation
- requires a side mounted condenser and a carefully designed exhaust duct and expansion joint/tie-rod system
- side exhaust can be employed with air-cooled condensing systems

iii) **Horizontal (Axial) Exhaust:**
- usually slightly better turbine efficiency, compared to down exhaust
- allows the unit to be placed upon a low “monolithic” block foundation, which is potentially less expensive than the tabletop foundation
- may result in a longer and larger plot plan for water-cooled applications. Care must be paid to expansion joints and condenser and turbine supports
- axial exhaust can be employed with air-cooled condensing systems
5.0 STEAM TURBINE AUXILIARY SYSTEMS

5.1 Turbine Control System

- Generally an electronic digital control system integrating speed, load and/or pressure control, etc. Feedback signals are utilized to allow the control system to operate in closed loop or open loop mode.
- May be a proprietary PLC-based governor (Woodward/Tri-Sen) system, or the Vendor’s proprietary system, with communication interface to the plant control system.
- Generally integrated with the generator controls or compressor/pump controls (as applicable).

5.2 Speed Control and Overspeed Systems

- Speed probes (generally three) operating opposite a multi-tooth shaft wheel, providing the control system with a high resolution speed feedback signals.
- Overspeed detection probes (generally three) operating opposite the toothed shaft wheel, providing the necessary signals to cause emergency shutdown (sometimes with mechanical bolt overspeed backup).
- All systems integrated with turbine control and trip system.

5.3 Vibration Monitoring Systems

- Either a stand-alone package or integrated with a proprietary vendor’s control system.
- Radial X-Y (90-degree) vibration probes, mounted at turbine and driven equipment bearings.
- Axial clearance probes, generally at the turbine thrust bearing.
- Eccentricity probe, used for low speed (turning gear) evaluation of shaft distortion.
- Key phasor, reference point for field balancing.

5.4 Temperature Monitoring Systems

- Either a stand-alone package or integrated with a proprietary vendor’s control system.
- Thermocouples or RTD’s mounted in journal and thrust bearing pads or in the bearing lube oil drain lines.
- Thermocouples or RTD’s mounted in the lubricating oil reservoir.
- RTD’s mounted in generator stator (where applicable).
- All systems integrated with turbine control, monitoring and alarm/trip system.

5.5 **Lubricating and Control/Hydraulic Oil System**

- One primary (either AC motor-driven or shaft-driven) lubricating oil pump.
- One backup (AC motor-driven) lubricating oil pump, with automatic on-line transfer.
- One emergency (DC motor-driven) lubricating oil pump (bearings only).
- Duplex water-to-oil shell and tube lubricating oil coolers, or fin-fan lubricating oil cooler (where water generally not available; use glycol interface system in cold ambients).
- Duplex lubricating oil and control oil filters.
- Automatic pressure and temperature regulation valves.
- Lubricating oil reservoir with heaters and level switches.

5.6 **Gland Steam Sealing System**

- Required to prevent steam leakage to atmosphere from the turbine high pressure shaft end(s), and to prevent air infiltration into the exhaust hood at the low pressure shaft end.
- Requires a separate steam source during initial condenser vacuum raising period and initial turbine start-up and during emergency shutdown. After start-up, the system is primarily self-sustaining.

5.7 **Turning Gear**

- When turbine rotors are of sufficient length, a turning gear is installed to slowly rotate the drivetrain before start-up and after shutdown.
- The turning gear system prevents thermal bowing of the rotor, and assists in preventing casing thermal distortion due to top-side heating during shutdown.
- Turning gears can generally be automatically and/or manually engaged, but are always interlocked with lubricating oil pressure sensors, to prevent bearing damage.
• Turning gears can be either AC motor-driven or DC motor-driven, depending on the security of each respective supply and battery bank capabilities.

5.8 Generator Control Systems (where applicable)
• Excitation and voltage regulation systems
• Automatic and/or manual synchronizing systems
• Var and power factor closed loop control systems
• Generator and system relay protection systems

5.9 Generators
• Most steam turbine generator (STG) applications use 3-phase synchronous generators, and for 60 Hz applications, are rated at either 4.16 kV or 13.8 kV and operate at either 1800 rpm or 3600 rpm, both depending upon the unit’s size.
• Generators can utilize either brushless or static excitation.

5.10 Gearboxes
• The optimum speed of smaller steam turbines is generally in the range of 4000 to 6000 rpm. Therefore, gearboxes are used to reduce the turbine output speed to either 1800 or 3600 rpm, as required by the generator or compressor itself.
• These gearboxes can be single or double herringbone offset designs (either horizontal or vertical) or epicyclic designs. Gearboxes dramatically increase the lubricating oil and heat rejection requirements of a STG package and may decrease the overall efficiency slightly.
• Larger cogeneration steam turbines are frequently optimized to operate at 3600 rpm and, therefore, can be directly connected from the turbine to the 3600 rpm generator (direct drive)

5.11 Mechanical Drive Control Systems (where applicable)
• Compressor surge protection utilized, when applicable.