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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.

ABSTRACT

This paper describes how gas 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 and simplified calculations are then given, showing how a gas turbine generator (GTG) could be integrated into the Base Case* facility, to ultimately save money. The examples progressively increase in complexity, flexibility, cost and efficiency, and include:

i) GTG in Open Cycle Configuration
ii) GTG with Unfired HRSG
iii) GTG with Fired HRSG
iv) Small Combined-Cycle Cogeneration Plant
v) Large Combined-Cycle Cogeneration Plant

In the Mechanical Power Applications section, the BASE CASE scenario is a typical Utility Pipeline Gas Compressor application using a mechanical drive gas turbine. Sequential examples are then given showing how combined-cycle using steam turbine generators could be applied to the typical plant.

The paper includes a very general discussion on Turbine Selection Criteria, including turbine sizing considerations and aero-derivative vs. heavy-duty industrial comparisons.

* For an illustration of how a steam turbine generator could be integrated into the same Base Case facility, please refer to the Steam Turbine Applications© paper.
# GAS TURBINE APPLICATIONS

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1.0 ELECTRIC POWER GENERATION APPLICATIONS

1.1 The 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></td>
<td>$/kw</td>
<td>¢/kw.hr</td>
</tr>
<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 $3.25 per mmbtu$_{HHV}$, the annual fuel costs are approximately:

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

\[
\approx 3.28 \text{ million per year}
\]

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

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity +</td>
<td>$10.76 \text{ million} + $3.28 \text{ million}</td>
</tr>
<tr>
<td>Fuel Costs</td>
<td>$14.04 \text{ million per year}</td>
</tr>
</tbody>
</table>

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

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

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

\[
\text{Overall HHV} = \frac{\text{Heat Output}}{\text{Fuel Input}}
\]

\[
\text{Efficiency} = \frac{100.8 \text{ mmbtuh}}{126.0 \text{ mmbtuh}_{\text{HHV}}} = 80\%
\]

The company president reviews the factory's annual operating costs, and notes:

“We’re spending $14 million a year on energy!
Is there anything we can do about it?”

Thus, the steam plant staff will commence a study of the potential means to reduce energy costs, by looking at several alternatives as illustrated* in the following examples.

* The following examples are very simplified, merely using the ISO-type gas turbine generator performance cataloged data from the Gas Turbine World Handbook listings, with no further adjustment for site elevation, for winter and summer ambient temperatures, or for additional auxiliary losses.

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
Gas Turbine Generator in Open Cycle Configuration

Referring to the enclosed Alternative 1 graphic, a small gas turbine generator could be installed at the industrial facility, in open (simple) cycle configuration without any exhaust heat recovery. This, of course, would not be cogeneration, but we will examine the opportunities it might provide.

The gas turbine generator uses about 157.5 mmbtu_HHV of fuel to produce approximately 12.61 MW.

The Process Steam requirements would still be met by the existing Steam Plant facilities, and its fuel load would remain the same, at 126.0 mmbtu_HHV ($3.28 million per year).

For the situation illustrated on the Alternative 1 graphic, the approximate cost of the electrical power (not including financial factors) produced by this open-cycle gas turbine generator is:

\[
\text{Cost of Power} = \frac{\text{Cost of Fuel}}{\text{Power Production}} = \frac{[157.5 \text{ mmbtu}_\text{HHV} \times $3.25/\text{mmbtu}_\text{HHV}]}{12,610 \text{ kW}} = 4.1 \text{ ¢/kw.hr}
\]

This simplified Cost of Self-Generated Power rate is less-expensive than the average on-peak purchase rate (7.9 ¢/kw.hr), but more expensive than the off-peak purchase rate (2.9 ¢/kw.hr). Therefore, this simple-cycle unit should be operated in an on-peak period shaving mode only.

Thus, assuming that there are 4,000 on-peak hours per year, the annual fuel costs attributable to the gas turbine generator itself would be approximately:

\[
\text{GTG Fuel Cost} = 157.5 \text{ mmbtu}_\text{HHV} \times 4,000 \text{ hrs/yr} \times 3.25 \frac{\text{$/mmbtu}_\text{HHV}}{\text{}} = $2.05 \text{ million per year}
\]

Combined with the Boiler fuel, the new annual Total Fuel Cost will increase to:

\[
\text{Total Fuel Costs} = $3.28 \text{ million} + $2.05 \text{ million} = $5.32 \text{ million per year}
\]

Since the GTG Power Output is about 12.61 MW, the amount of power now purchased during on-peak periods is reduced from 25 MW to about 12.4 MW.

The electrical savings are approximately:

\[
\text{Electrical Savings} = 12,610 \text{ kW} \times 7.9 \text{ ¢/kw.hr} \times 4,000 \text{ hr/yr} = $3.99 \text{ million per year}
\]
For a reduced Annual Electrical Cost of:

New Electrical Costs = $10.76 - $3.99

The total facility energy costs are now:

Electricity + Fuel Costs = $5.32 million + $6.79 million

Compared to the Base Case, this represents an annual energy savings of:

Energy Savings = $14.0 million - $12.1 million

Initially this appears to be a good 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 $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:

Net Annual Savings = $1.9 - $0.8 - $0.2

= $0.9 million per year

The simplified Payback Period for this plant is about:

Payback Period = Capital Cost / Net Annual Savings

= $9.0 million / $0.9 million

= 10 years

For reference, the Heat to Power ratio of the new Alternative 1 equipment (which delivers no heat) is:

Equipment H to P Ratio = [0.0 mmbtuh] / [12,610 kW x 3,413 btu/kw.hr]

= 0.0

The efficiency (HHV) of the new Alternative 1 equipment is only:

Equipment HHV = Power Output /Fuel Input

Efficiency = [12,610 kW x 3,413 btu/kw.hr] / 157.5 mmbtuh_{HHV}

= 43.0 mmbtuh / 157.5 mmbtuh_{HHV}

= 27%

By adding waste heat recovery to the gas turbine exhaust in the next example, we will decrease the plant's net fuel usage, thus increasing the facility efficiency.
1.3 Alternative 2
Gas Turbine Generator with Unfired Heat Recovery Steam Generator

Referring to the enclosed Alternative 2 graphic, an unfired heat recovery steam generator (HRSG) could be added to the exhaust of the same gas turbine generator. The total amount of Process Steam produced is identical to the BASE CASE, with about two-thirds of it coming from the unfired HRSG and the remainder coming from the existing Steam Plant facilities. The “free” steam from the HRSG saves approximately \(126.0 - 40.5 = 85.5\) mmbtuH\(_{HV}\) of fuel use in the Steam Plant.

For the situation illustrated on this graphic, the cost of the electrical power produced by the gas turbine generator can include a credit for the fuel saved in the Steam Plant, thus:

\[
\text{Cost of Power} = \frac{\text{Cost of GTG Fuel} - \text{Steam Plant Fuel Credit}}{\text{Power Output}}
\]

\[
= \frac{[157.5 \text{ mmbtu}_{HV} - 85.5 \text{ mmbtu}_{HV}] \times 3.25/\text{mmbtu}_{HV}}{12.610 \text{ kW}}
\]

\[
= \frac{72.0 \times 3.25}{12.610}
\]

\[
= 1.8 \text{ c/kw.hr}
\]

This is significantly less than the off-peak period purchase rates (2.9 c/kw.hr), thus the cycle can probably be operated economically all year round.

The GTG offsets an average of 12.61 MW of purchased power all year round, thus the annual electrical costs decrease to approximately:

\[
\text{Electrical Costs} = [25,000 \text{ kW} - 12,610 \text{ kW}] \times 8,000 \text{ hrs/yr} \times 5.4 \text{ c/kw.hr}
\]

\[
= 5.33 \text{ million per year}
\]

The total fuel requirements, including both the gas turbine generator and the Steam Plant is now roughly \(157.5 + 40.5 = 198.0\) mmbtuH\(_{HV}\), for an annual cost of:

\[
\text{Fuel Costs} = 198.0 \times 8,000 \times 3.25
\]

\[
= 5.15 \text{ million per year}
\]

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

\[
\text{Electricity + Fuel Costs} = 5.33 \text{ million} + 5.15 \text{ million}
\]

\[
= 10.5 \text{ million per year}
\]
Compared to the BASE CASE, this is a net decrease, or potential savings of:

**Energy** = $14.0 million - $10.5 million  
**Savings** = **$3.6 million per year**

For a plant capital cost of $12.5 million, the debt payments are about $1.1 million per year. Combined with an annual O&M cost of about $0.5 million per year, the **Net Annual Savings** of this Alternative 2 is about **$2.0 million per year**, and the simplified **Payback Period** is reduced to about **6.5 years**.

The overall efficiency of the complete industrial facility, including the Steam Plant and the new Alternative 2 equipment has increased to:

**Overall EffiencyncientHHV** = \[
\frac{\text{[Power + Heat, total]}}{\text{Fuel, total}}
\]

\[
\text{Efficiency}_{HHV} = \frac{[43.0 \text{ mmbtuh} + 100.8 \text{ mmbtuh}]}{198.0 \text{ mmbtuh}_{HHV}} = 73%
\]

The Heat to Power ratio of the Alternative 2 “cogeneration” equipment is:

**Equipment H to P Ratio** = \[
\frac{[67,900 \text{ lb}_{stm}/\text{hr} \times 1,008 \text{ btu/lb}_{stm}]}{[12,610 \text{ kW} \times 3413 \text{ btu/kw.hr}]}
\]

\[
= \frac{68.4 \text{ mmbtuh}}{43.0 \text{ mmbtuh}} = 1.59
\]

which is a fairly good match to the BASE CASE Heat to Power Ratio of 1.18.

This Alternate 2 demonstrates a more expensive, but more efficient cycle which is capable of providing process steam, at no extra fuel cost compared to Alternative 1, resulting in a significant reduction in facility operating costs, and an improvement in the simplified Payback Period.

However, we have only partially satisfied the total heat and total power demands of the industrial facility.

In the next example, we will address the remainder of the heat load.
1.4 Alternative 3
Gas Turbine Generator with Fired Heat Recovery Steam Generator

Referring to the enclosed Alternative 3 graphic, a larger capacity HRSG with a duct burner is added to the exhaust of the same gas turbine generator, instead of the previous Alternative 2 smaller, unfired HRSG unit.

The amount of duct burner firing is varied as required, to provide all the Process Steam. The existing Steam Plant is no longer shown, since in this scenario, it is no longer providing steam (in practice, the water treatment, condensate and feedwater, etc. facilities in the Steam Plant would still be required).

As in Alternative 2, the GTG still offsets 12.61 MW of purchased power, thus the facility's annual Electrical Costs remain at $5.33 million per year.

Approximately 35.2 mmbtuH \text{H}_{\text{HV}} \text{ of fuel is required in the HRSG duct burner to raise the remaining 32 kpph of Process Steam. Thus, the total fuel consumption is roughly } 157.5 + 35.2 = 192.7 \text{ mmbtuH}_{\text{HV}}. \text{ The facility's annual Fuel Costs thus increase further to approximately } $5.01 \text{ million per year.}

The facility's total Energy Costs reduce to $10.3 \text{ million per year, for a net Energy Savings of } $3.7 \text{ million per year.}

Based upon a Capital Cost of $13.2 million, the Debt Repayment is approximately $1.2 \text{ million per year. Combined with an annual O&M Cost of approximately } $0.5 \text{ million, the Net Annual Savings are approximately } $2.0 \text{ million per year, for a simplified Payback Period of about 6.6 years.}

The Efficiency of this cycle has increased to approximately 75\%, while the equipment Heat to Power Ratio now is 2.34.

Compared to the Base Case, we have provided all the process heat, but it is still feasible to make more electrical power, in order to bring the H to P ratio closer to the existing 1.18.

Compared to Alternative 2, we can see that this Alternative 3 scheme with the addition of a duct burner, allows the cogeneration equipment to actually follow the steam loads, as they vary.

The amount of electrical power produced by the GTG is relatively constant, and the cycle lacks the ability to follow variations in Plant electrical load, which will be addressed in the next alternative.
1.5 Alternative 4

Small Combined-Cycle Cogeneration Plant

Referring to the enclosed Alternative 4 graphic, a fairly expensive combined-cycle cogeneration plant is shown, using the same gas turbine generator, an even larger, high-pressure fired HRSG, and an auto-extraction condensing steam turbine generator (STG).

Because of the high steam pressure system shown, new feedwater, water treatment, etc. facilities will be required. A condenser and large quantities of condenser cooling water 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 4 “cogeneration” equipment is about 68%, while the cycle perfectly matches the original Heat to Power Ratio of 1.18.

As depicted, this Alternative 4 can supply all the required Process Steam and all the required Electricity, with inherent flexibility to follow normal variations in each.

This Alternative 4 is relatively expensive, but still maintains good efficiency and a reasonable Payback Period.
1.6 Alternative 5
Large Combined-Cycle Cogeneration Plant

Referring to the enclosed Alternative 5 graphic, an even larger and more expensive combined-cycle cogeneration plant is shown, with a 50 MW GTG, a large fired HRSG and an auto-extraction condensing STG. This facility makes all the required electricity (and more) and all the required process steam.

This is a small version of the typical combined-cycle cogeneration plant which has been constructed in North America over the past decade, typically by third-party developers, especially in the USA under the PURPA Act.

In this example, we have assumed that our industrial facility is the investor, and that the electrical power made in excess of 25 MW could and would be sold to the electrical utility at about the same rate as the previous purchase rate.

The total power output of the cycle at the operating condition shown, is 51.2 + 23.8 = 75.0 MW. Having satisfied the internal 25 MW demand, i.e. Electrical Purchase Costs are zero, there is still about 50.0 MW available for sale to the utility.

The resultant revenue from Electricity Sales would be approximately $21.53 million per year, although the Fuel Cost would be approximately $16.32 million per year, for a Net Revenue of approximately $5.32 million per year.

Since the Facility owner is the investor, the Net Annual Savings/Revenue will include the original $14.0 million savings, plus the above Net Revenue, for a Net Benefit of about $19.3 million per year.

For a plant Capital Cost of about $50 million (annual Debt Repayment of about $4.5 million) and a $3.0 million annual O&M Cost, the Net Annual Savings are approximately $11.8 million per year, for a Payback Period of about 4.3 years.

The plant Efficiency is approximately 57%, and the equipment Heat to Power Ratio is about 0.34, both demonstrating the domination of electrical power production in this Alternative 5 cycle.

On paper, this Alternative 5 looks much more attractive (i.e. best Payback Period) than any of the previous alternatives. However, because of the amount of capital required, the industrial facility would rarely execute this project without a partner. Because of the risk associated with using only 1 x 50 MW GTG as the basis of the plant, the proponent may want 2 x 25 MW GTGs instead, or some alternate configuration. These factors could increase the plant cost and/or diminish the project economic returns.
### 1.7 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>1</td>
<td>Base Case + Open Cycle GTG</td>
<td>27%* on-peak</td>
<td>0.0*</td>
<td>$9.0</td>
<td>12.1+1.0 ~ $13.1</td>
<td>$0.9</td>
<td>10 years</td>
</tr>
<tr>
<td>2</td>
<td>Base Case + GTG w/ Unfired HRSG</td>
<td>73%*</td>
<td>1.59*</td>
<td>$12.5</td>
<td>10.5+1.5 ~ $12.0</td>
<td>$2.0</td>
<td>6.5 years</td>
</tr>
<tr>
<td>3</td>
<td>Base Case + GTG w/ Fired HRSG</td>
<td>75%</td>
<td>2.34*</td>
<td>$13.2</td>
<td>10.3+1.7 ~ $12.0</td>
<td>$2.0</td>
<td>6.6 years</td>
</tr>
<tr>
<td>4</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>
<tr>
<td>5</td>
<td>Large Combined Cycle Plant</td>
<td>57%</td>
<td>0.34</td>
<td>$50.0</td>
<td>-5.2+7.5 ~ $2.2</td>
<td>$11.8</td>
<td>4.3 years</td>
</tr>
</tbody>
</table>

* For the new equipment only.

** Including fuel, electricity purchases/revenues, O&M and finance charges, as applicable.
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.
GAS TURBINE APPLICATIONS ©

Electric Power Generation Applications
Alternative 1 - Gas Turbine Generator in Open (Simple) Cycle Configuration, during On-Peak Hours Only

**ALTERNATIVE 1 SCENARIO**
A SIMPLE CYCLE gas turbine generator is installed to operate during ON-PEAK PERIODS only (4,000 hrs/yr), reducing on-peak demand and energy charges. The Steam & Boiler Plant still provides the required process steam. Capital Cost about $9 million CAD.

**Advantages**
Net Utility purchase costs reduced from $14.0 mm to $12.1 mm, a "savings" of $1.9 mm /yr.

**Disadvantages**
**The annual finance charge ($0.8 mm) and O&M costs ($0.2 mm) reduce these savings to about $0.9 mm/yr.**
Simple payback about $9.0 / $0.9 = 10 years.
GT exhaust heat wasted. Overall on-site efficiency could be better.
Backup Power Agreement required with electrical Utility.

**On-Site Energy Production**
During On-Peak Periods
- Heat Made: 100.8 mmbtu/hr
- Power Made: 43.0 mmbtu/hr
- Fuel Used*: 283.5 mmbtu-HHV
- Thermal Efficiency*: 51%
- Heat/Power Ratio*: 2.34

**Facility Utility Purchase Costs**
- Boiler Fuel: $410 per hour
- GTG Fuel*: $512 per hour*
- Fuel Cost: $5.32 million/yr
- Elect Purch: 12.4 MW-on peak
- Elect Purch: 25.0 MW-off peak
- Elect Purch: $6.79 million/yr
- Total Utility Cost / yr reduced to: $5.32 + $6.79 = $12.1 million

* During On-Peak hours only

**Simplified Investment Potential**
- Base Case minus Alt. 1:
  $14.0 - $12.1 = $1.9 million/yr
- Potential savings for gas turbine investment purposes

**Finance and O&M costs to be paid from $1.9 mm savings**
GAS TURBINE APPLICATIONS ©

Electric Power Generation Applications

Alternative 2 - Gas Turbine Generator with Unfired Heat Recovery Steam Generator, Operated Year-Round

**On-Site Energy Production**
- Heat Made: 100.8 mmbtuh
- Power Made: 43.0 mmbtuh
- Fuel Used: 198.0 mmbtuh-HHV
- Thermal Efficiency: 73%
- Heat/Power Ratio: 2.34

**Facility Utility Purchase Costs**
- Fuel Cost: $643 per hour
- Fuel Cost: $5.15 million/yr
- Elect Purch. (MW-on peak): 12.4
- Elect Purch. (MW-off peak): 12.4
- Elect Purch. (MW-off peak): $5.33 million/yr
- Total Utility Cost / yr reduced to: $5.15 + $5.33 = $10.5 million

**Simplified Investment Potential**
- Base Case minus Alt. 2:
  - $14.0 - $10.5 = $3.6 million/yr
- Potential savings for gas turbine & HRSG investment purposes

**Disadvantages**
- Annual finance charge of $1.1 mm and O&M cost of $0.5 mm reduce savings to about $2.0 mm/yr. Simple payback about $12.5 / $2.0 = 6.5 years.
- With an unfired HRSG, the HRSG steam production can not be controlled.
- Increased plot plan requirements, near to the Steam Plant. Backup Power Agreement required with Utility.

**ADVANTAGES**
- A nominal "savings" of $3.6 mm/yr, compared to Base Case.
- On-site operating efficiency increased.

**ALTERNATIVE 2 SCENARIO**
A low-pressure, unfired HRSG is installed on the GTG exhaust to recover waste heat and generate process steam. Less steam is required from the Steam Plant itself. The existing Steam Plant feedwater, condensate and water treatment systems are kept.

Capital Cost about $12.5 million CAD.

Prepared by:
Gryphon International Engineering Services Inc.
GAS TURBINE APPLICATIONS

Electric Power Generation Applications

Alternative 3 - Gas Turbine Generator with Fired Heat Recovery Steam Generator, Operated Year-Round

Fuel
HHV

43 mmbtuh

157.5 mmbtuh

Comb

35.2 mmbtuh

1,017 deg F

1,339 deg F

Process Steam
125 psig
375 deg F
100 kph
100.8 mmbtuh (net)

Gen MW 12.6

GT Compressor

GT Turbine

Duct Burner

Heat Recovery Steam Generator

The Steam & Boiler Plant is no longer shown, since it's only required for backup now.
The existing feedwater, condensate and water treatment systems are kept.

ALTERNATIVE 3 SCENARIO
A larger, low-pressure HRSG, with duct firing capability, is installed on the GT exhaust, in lieu of an unfired HRSG.
The amount of HRSG duct burner firing is varied to follow process steam load. Less, or no steam is required from the Steam Plant itself, and the existing boilers could potentially be retired or maintained as backup.
Capital Cost about $13.2 million CAD.

Advantages
A nominal "savings" of $3.7 mm/yr, compared to the Base Case.
On-site operating efficiency further increased. Process steam load can be followed, via duct burner.

Disadvantages
**The annual finance charge of $1.2 mm, and the annual O&M cost of $0.5 mm reduce savings to about $2.0 mm Cdn/yr. Simple payback about $13.2 / $2.0 = 6.6 years.
Increased plot plan requirements, near to the Steam Plant.
Backup Power Agreement required with electrical Utility.

On-Site Energy Production
Heat: 100.8 mmbtuh
Power: 43.0 mmbtuh
Fuel: 192.7 mmbtuh-HHV
Thermal Efficiency: 75%
Heat/Power Ratio: 2.34

Facility Utility Purchase Costs
Fuel Cost: $626 per hour
Fuel Cost: $5.01 million/yr
Elect Purch: 12.4 MW-on peak
Elect Purch: 12.4 MW-off peak
Elect Purch: $5.33 million/yr
Total Utility Cost per year
$5.01 + $5.33 = $10.3 million

Simplified Investment Potential**
Base Case minus Alt. 3:
$14.0 - $10.3 = $3.7 million/yr
Potential savings for gas turbine & HRSG investment purposes

** Finance and O&M costs to be paid from $3.7 mm savings
**GAS TURBINE APPLICATIONS ©**

*Electric Power Generation Applications*

**Alternative 4 - Small Combined-Cycle Cogeneration Plant**

---

**Fuel**

- **HHV**
  - 157.5 mmbtuh
  - 117.5 mmbtuh

**Process Steam**

- 125 psig
- 375 deg F
- 100 kpph
- 100.8 mmbtuh (net)

---

**On-Site Energy Production**

- **Heat**: 100.8 mmbtuh
- **Power**: 85.3 mmbtuh
- **Fuel**: 275.0 mmbtuh-HHV
- **Thermal Efficiency**: 68%
- **Heat/Power Ratio**: 1.18

---

**Facility Utility Purchase Costs**

- **Fuel Cost**: $894 per hour
- **Fuel Cost**: $7.15 million/yr
- **Elect Purch**: 0.0 MW-on peak
- **Elect Purch**: 0.0 MW-off peak
- **Elect Purch**: $0.00 million/yr

**Total Utility Cost per year**:

\[
\$7.15 + \$0.00 = \$7.1 \text{ million}
\]

---

**Condenser Cooling Water**

- 7800 USgpm

---

**Simplified Investment Potential**

**Base Case minus Alt. 4:**

\[
\$14.0 - \$7.1 = \$6.9 \text{ million/yr}
\]

Potential savings for combined cycle investment purposes

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

---

**ALTERNATIVE 4**

**SCENARIO**

A small combined-cycle including the GTG, a larger high-pressure fired HRSG and an extraction-condensing STG. The combined power output could displace all the previously purchased power. An extraction on the steam turbine provides the required process steam. Capital Cost about $23.5 million CAD.

**Advantages**

A nominal "savings" of $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 charge of $2.1 mm and annual O&M cost of $1.2 mm reduce the savings to $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.

---

Prepared by:

Gryphon International Engineering Services Inc.
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Electric Power Generation Applications

Alternative 5 - Large Combined-Cycle Cogeneration Plant

**ALTERNATIVE 5 SCENARIO**
The Facility installs a large combined cycle plant, providing all their power and steam needs.
Excess power is sold to the electrical Utility (50 MW shown).
Cost about $50 mm CAD.

**Advantages**
Electrical purchases reduced to zero. Fuel costs very high, but a net revenue of $5.2 mm/yr due to electrical sales is realized. Total "savings" about $19.3 mm/yr.
Plant is flexible to follow facility electrical & steam load, and to manage electrical demand.

**Disadvantages**
**The annual finance charge of $4.5 mm and the annual O&M costs of $3.0 mm reduce savings to $11.8 mm/yr. Simple payback about $50 / $11.8 = 4.3 years.
New steam, feedwater, makeup water plants required. Cooling water or other condensing means required. Backup Power Agreement and Power Sales Agreement required.

Prepared by:
Gryphon International Engineering Services Inc.
2.0 MECHANICAL POWER APPLICATIONS

Today, aero-derivative gas turbines are typically installed in gas pipeline compression applications, due to their relatively high efficiency, quick startup capability and the ability for quick maintenance changeout.

In the past, low-pressure ratio two-shaft industrial-type gas turbines (frequently with recuperators to raise efficiencies) were installed for pipeline gas compression service. Many of these older units are still operating.

A typical 30,000-hp multi-shaft aero-derivative gas-turbine which is driving a gas-compressor is shown on the enclosed graphic.

2.1 Potential Combined Cycle Application 1

As shown on the subsequent graphic, in certain circumstances it is possible to add waste heat recovery to the exhaust of this turbine-compressor set, and to make high pressure steam for introduction into a condensing steam turbine generator set. When these compressor stations are located in remote areas without significant quantities of cooling water, an air-cooled condenser is required for the steam turbine set.

This is a cogeneration cycle, since two useful forms of energy, electricity (about 7.5 MW) and mechanical power (30,000 hp of gas compression) are produced from the same initial fuel source.

The incremental cost of the combined cycle equipment (about $16.0 million), combined with the low amounts of electrical power which can be sold, result in a fairly long Payback Period for this plant, about 10.4 years.

It must also be noted that the operation of the turbine-compressor unit is normally controlled by the pipeline system flow/pressure requirements, and is possibly being stopped and started rather frequently, or continually operated only at partial load. Such a variance in operating modes would adversely impact the power output of the cycle, and thus the economic return.

The next example alternative will address a means of diminishing these problems.
2.2 Potential Combined Cycle Application 2

To increase the revenues of the plant, an additional GTG set, HRSG and a larger condensing STG set could be installed, as shown on the enclosed graphic.

Variations of this type of plant have been constructed on several locations along the Canadian gas pipeline system. The extra GTG could be either an aero-derivative or heavy-duty industrial unit.

For the situation shown on the Alternative 2 graphic, the Payback Period is approximately 3.7 years, about 3 times quicker than the simpler but more riskier (economically) Application 1.
Typical Compressor Station Existing Scenario
Multi-shaft aero-derivative gas turbines are typically used in gas pipeline compression service, due to their relatively high efficiency, quick changeout capability (for maintenance) and quick startup capability.
GAS TURBINE APPLICATIONS

Mechanical Power Applications
Potential Combined Cycle Application 1 for Gas Compressor Stations

Fuel - HHV
231.9 mmbtu/h

Comb

Two Shaft Gas Turbine

GT Compressor

CT

PT

Natural Gas Compressor

900 psig
1.31 bcf/day

30278 HP Compression

700 psig

HP HRSG Steam
900 psig
900 deg F
56.8 kpph

Heat Recovery
Steam Generator

Gen MW
7.5

Steam
Turbine

2.0 in HgA

Air Cooled Condenser

SCENARIO NO. 1
The diagram shows a very simple potential combined-cycle application for gas compression stations. Waste heat is recovered from the gas turbine exhaust to generate steam for a condensing steam turbine generator.

Advantages
- Moderate net income.

Disadvantages
- Power output is subject to pipeline operating demand, i.e. up, down and/or off.
- For the assumptions shown, payback period is too long.
- Need area at compressor station, cycle water, possibly power lines, etc.
- Increased backpressure on compressor drive turbine decreases utility compression capability - hidden cost.

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Electrical Sales:</td>
<td>3.7</td>
</tr>
<tr>
<td>Annual Fuel Cost:</td>
<td>0.0</td>
</tr>
<tr>
<td>Annual O&amp;M Cost:</td>
<td>0.3</td>
</tr>
<tr>
<td>Incremental Operators:</td>
<td>0.5</td>
</tr>
<tr>
<td>Annual Finance Cost:</td>
<td>1.4</td>
</tr>
<tr>
<td>Total Expenses</td>
<td>2.2</td>
</tr>
<tr>
<td>Net Income</td>
<td>1.5</td>
</tr>
<tr>
<td>Simple Payback Period</td>
<td>10.4  yrs</td>
</tr>
</tbody>
</table>

Assumptions: Avg. electrical sale price $6.00/kw.hr;
Fuel cost $3.25/mmbtu; 95% avail'ty (8322 hr/yr) with 100% utilization. Plant cost of $16.0 million.
Mechanical Power Applications
Potential Combined Cycle Application 2 for Gas Compression Stations

Fuel - HHV
231.9 mmbtu/h

Comb

GT Compressor

Two Shaft Gas Turbine

Fuel - HHV
466.5 mmbtu/h

Comb

GT Compressor

51.2 MW

GT Turbine

Gas Turbine Generator

Natural Gas
900 psig
1.31 bcf/day
30278 HP
Compression
700 psig

Natural Gas Compressor

Gen MW
25.1

Steam Turbine

HP HRSG Steam
900 psig
900 deg F
190 kpph

Air Cooled Condenser

Heat Recovery Steam Generator

Heat Recovery Steam Generator

Scenario 2
Scenario 1 is expanded with a new, large gas turbine generator, an additional HRSG and bigger STG and condenser.

Advantages
- Good net income
- Power output is less sensitive to pipeline operations

Disadvantages
- Need area at compressor station, cycle water, possibly power lines, etc
- Still the hidden cost of increased backpressure on compressor drive turbine

Prepared by:
Gryphon International Engineering Services Inc.
3.0 **TURBINE SELECTION CRITERIA**

Cogeneration proponents frequently ask:

- What’s the best gas turbine?
- What’s the best kind of turbine, aero-derivative or heavy duty industrial?
- How many should we get?
- Should be get a steam turbine too?

There is no single correct answer to these questions. Each cogeneration opportunity requires a thorough evaluation, considering all of the proponent’s applicable factors such as:

a) The existing power load and their seasonal, weekly and daily variations.
b) The existing electrical and fuel purchase costs.
c) The capability to provide additional fuel to the facility.
d) The existing system gas pressures (where applicable).
e) The existing heat load and their seasonal, weekly and daily variations.
f) The condition of existing steam plant equipment (boilers, water treatment, feedwater and condensate systems) and physical facilities.
g) The allowable downtime for maintenance of the cogeneration equipment.
h) The impact of forced outages on the facility's production.
i) The allowable project risk.
j) The corporation's capital investment capability and how many other proposed projects in the facility are competing for the capital required for a cogeneration project.
k) The incremental manpower and resources which would be required to support a cogeneration project.

The following two sections outline only some considerations.

3.1 **Turbine Sizing**

Gas turbines are available in a wide selection of capacities and efficiencies.

**Aero-Derivative** units are available from fractional MW sizes (0.3 to 0.6 MW) up to approximately 50 MW. All these units are usually more efficient (up to 40% or 42% - LHV) than their industrial cousins, but where waste heat recovery is required, will usually not produce as much “waste heat”.
Heavy-duty Industrial gas turbines are available from fractional MW sizes (0.3 to 0.6 MW) up to approximately 240 MW. Above 50 MW (per unit), the only GTG choice would be heavy-duty industrial. These industrial units are generally not as efficient in simple cycle as their aero-derivative cousins, but will produce more "waste heat".

3.2 Aero-Derivative vs. Heavy Duty Industrial

In this section, we will outline some generalized fundamental differences between aero-derivative gas turbines:

<table>
<thead>
<tr>
<th>Performance</th>
<th>Aero-Derivative</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Susceptible to compressor fouling and icing, and foreign object damage</td>
<td>More robust compressor and inlet configuration</td>
<td></td>
</tr>
<tr>
<td>Frequent compressor washing required</td>
<td>Compressor washing still required, but less frequently</td>
<td></td>
</tr>
<tr>
<td>Some units fall off, or actually decrease power output as ambient temperature decreases</td>
<td>For most units, power increases to the generator limit as ambient temperature decreases</td>
<td></td>
</tr>
<tr>
<td>Fairly tolerant of cyclic duty</td>
<td>Optimized for continuous duty at base load</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fuel Considerations</th>
<th>Aero-Derivative</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas to light distillates and jet fuel</td>
<td>Natural gas through to distillates and cheaper heavy or residual fuels</td>
<td></td>
</tr>
<tr>
<td>Generally requires high gas supply pressures</td>
<td>Generally requires a lower gas pressures</td>
<td></td>
</tr>
<tr>
<td>Expensive treatment of heavy/residual fuels required</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Start-up</th>
<th>Aero-Derivative</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quick start-up – 5 to 20 minutes</td>
<td>20 to 60 minutes, depending on size</td>
<td></td>
</tr>
<tr>
<td>Relatively low horsepower starters</td>
<td>High horsepower starters</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Loading</th>
<th>Aero-Derivative</th>
<th>Heavy Duty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quick loading, sometimes 10% - 25% per minute</td>
<td>Slower loading, 1% to 5% per minute</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Aero-Derivative</strong></td>
<td><strong>Heavy Duty</strong></td>
</tr>
<tr>
<td>----------------</td>
<td>----------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Shutdown</strong></td>
<td>Many aero-derivatives require a short time of motoring to cool internals after trip, but then can be shut down</td>
<td>Many units require 1-2 days on turning gear after shutdown, but could be motored to assist quicker cooldown.</td>
</tr>
<tr>
<td><strong>Maintenance</strong></td>
<td>Borescope inspection ports&lt;br&gt;Generally more frequent inspections required</td>
<td>Borescope inspection ports&lt;br&gt;Inspections less frequent, but requires longer shutdowns</td>
</tr>
<tr>
<td></td>
<td>Maintenance is more expensive (4 kw.hr) and not all can be done at site</td>
<td>Most maintenance can be done at site</td>
</tr>
<tr>
<td></td>
<td>Lease engines available</td>
<td>No lease engines</td>
</tr>
</tbody>
</table>