OPTIMAL INTEGRATION OF STEAM TURBINES IN INDUSTRIAL PROCESS PLANTS

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Outline

• Definitions: CHP and Efficiency
• Thermodynamics Review
• Energy integration theory
• CHP models
CHP = Combined Heat and Power (= energy utility system for the plant site)

Steam Turbines are Heat Engines that operate on the Rankine cycle. They convert $\Delta P$ into Shaftwork; a generator then converts Shaftwork into Elec power

Thermodynamic Efficiency is defined as

$$\text{Useful Energy Output} \over \text{Energy Input}$$

For Generation, 1 useful output = Power only. Machine eff $= \sim 20\%$, System Eff $= \sim 35\%$

For Cogeneration, 2 useful outputs = Power + Process Heat, Machine eff $= \sim 20\%$, but System Eff $\sim 75-80\%$
This is CHP, but **not** Cogeneration

LATENT HEAT OF ST EXHAUST IS **WASTED**

- **BOILERS**
  - FUEL
  - STEAM
  - **PURE POWER GEN**

- **STEAM TURBINE**
  - **KW**

- **PROCESS**

**BOILER EFF ~ 80%**
**POWER GEN EFF < 25%**
This is both CHP and “Co-Generation”

LAT HT OF EXHAUST STM IS USED IN THE PROCESS

OVERALL EFF ~ 75%
Alternative Cogen configurations

Extraction Turbine

Induction Turbine
Variations – hybrid Cogen and Condensing

Extraction turbine

Induction turbine
Simple Rankine Cycle flowsheet

Schematic shown is for cogeneration mode
Difficult to match Heat:Power ratio of process

4 Basic Configs – which do you think is most efficient?
The ultimate Combined-cycle Cogen scheme

OVERALL EFF ~ 85%

EXHAUST TO ATMOS

AIR

GAS

GAS TURBINE

HP STEAM

LP STEAM

ELEC EXPORT

PROCESS

HRSG
Different types of ST Efficiency

- **Machine Efficiency**
  \[ \text{Efficiency} = \frac{W}{Q_{in}} = \frac{(H_1 - H_2)}{H_1} \]

- **Isentropic Efficiency**
  \[ \text{Efficiency} = \frac{W}{[M.(H_1 - H_2)_{\text{max}}]} = \frac{(H_1 - H_2)}{(H_1 - H'_{2})} \]

- **System efficiency**
  \[ \eta = \frac{3413 \text{ kW} + (M - m) \lambda_2 + mH_2}{M \cdot H_1} \]

H'2 = exhaust vapor enthalpy IF the expansion were isentropic (which it is not, and can never be)
A Bit of History …

US Power plants stopped cogenerating ~1960
Rankine cycle on the P-V diagram

P-V Diagram for Water

1. BFW pumping
2. Steam generation in Boiler
3. ST expansion + power generation
4. Condensation
Power generation step (#3) on Mollier Chart

- **Adiabatic expansion** (from 600 psig, 700°F to 50 psig)
- **Isentropic efficiency**
Effect of $P_2/P_1$ on Machine Efficiency (W/Q_{in})

Near-optimal Inlet Conditions for industrial cogen systems

Theoretical Machine Efficiency tops out at ~13% for BPST and 24% for CST before moisture content in turbine reaches dangerous levels.
Effect of $P_2/P_1$ on System Efficiency

System Efficiency peaks when exhaust steam is saturated, drops rapidly as $P_2/P_1$ is falls, slowly as $P_2/P_1$ rises

Condensation starts at $P_2 = 53$ psig

Exhaust stm is wet

Exhaust stm is dry

System Efficiency vs $P_2/P_1$ ratio

System energy Eff

Exhaust

stm is dry

stm is wet
Next: What is the Optimum Exhaust Pressure?

- $P_2$ should be at a high enough pressure that it can be used for process heating.
- If there are multiple steam levels in the process, an extraction type turbine should be considered, with both exhaust pressures above ambient.
- The amounts should match the process steam requirements (→ “thermal match”)
- For higher $P_2$ or $W/Q_{in}$ → increase $P_1$ and $T_1$
OPTIMUM TURBINE INTEGRATION

It is possible to consolidate ALL the heating and cooling duties in the process into two **Composite Curves** that show the enthalpy change requirements between the entire temperature range over which the process operates.
The Pinch Principle - 1

If we allow $XP$ heat transfer, $Q_h$ and $Q_c$ both increase by $XP$.
To achieve the Energy Targets, **DO NOT**

- use Steam below Pinch
- use CW above Pinch
- transfer heat from process streams above Pinch to process streams below Pinch
Steam Turbine Integration options

No improvement in system $\eta$

100% conversion of $Q \rightarrow W$
Summary of Energy Balances

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Integrate Across PP</th>
<th>Integrate Above PP</th>
<th>Integrate Below PP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Process steam from fired boiler</td>
<td>A</td>
<td>A</td>
<td>A</td>
</tr>
<tr>
<td>Turbine steam from fired boiler</td>
<td>Q</td>
<td>Q</td>
<td>0</td>
</tr>
<tr>
<td>Turbine steam from WHB below Pinch</td>
<td>0</td>
<td>0</td>
<td>Q</td>
</tr>
<tr>
<td>Turbine exhaust vapor</td>
<td>Q – W</td>
<td>Q – W</td>
<td>Q – W</td>
</tr>
<tr>
<td>Net HP steam required</td>
<td>A + Q</td>
<td>A + W</td>
<td>A</td>
</tr>
<tr>
<td>Net Total Cooling Duty</td>
<td>B + (Q-W)</td>
<td>B</td>
<td>B – W</td>
</tr>
<tr>
<td>System energy efficiency</td>
<td>~20%</td>
<td>~95%</td>
<td>free power</td>
</tr>
</tbody>
</table>

= Machine efficiency
Grand Composite Curve - GCC

- HP STEAM
- LP STEAM
- COOLING WATER
- REFRIGERATION

Used for utilities selection
Correct Integration of Steam Turbine

• GCC shows us exactly how much HP and LP steam is needed, and the right P/T levels

• ST must always exhaust ABOVE the Process Pinch

• When designed this way, payback is very good, typically 3-4 yrs

\[
\text{Fuel} = \text{HPS} + \text{LPS} + W + Q_{\text{loss}}
\]
Net process cooling demand = available heat

Net process heating demand

Total Site Source-Sink curves
Optimize Configuration

EXISTING

OPTIMIZED

Power generation increased

Reduction in fuel consumption
CHP SIMULATION MODELS
Excellent Tool for Analysis

Model should include all Key System Features:

- Multiple steam levels
- Multiple boilers (with eff. curves)
- Process WHBs
- Steam and Gas turbines (incl HRSG)
- PRVs, Desuperheaters
- Condensate recovery (by steam pr level)
- Boiler blowdown flash & HX
- Deaerators (could be > 1)
- “Dump condenser”, if needed
- Economizer for BFW preheat
- BFW integration with process
- Process power demand
CHP Optimization Guidelines

- Set BPST exhaust pressures based on process steam headers (from GCC)
- Set steam flows through BPSTs based on process heating duties at each Pr level
- Condensing Turbines invariably a BAD idea
- Minimize flows through PRVs
- Use highest feasible DeAerator pressure(s)
- Maximize condensate recovery
- Preheat cold BFW makeup water by using it as a cooling medium in the process
On-line Utilities Optimization

Real-Time Optimizer finds the best way to operate all utilities subject to contractual, environmental and operational constraints.

- Hydrogen
- Fuel
- Steam
- Water
- Electricity

External Utilities Contracts
Emissions Regulations
Measurements
Optimum Set Points

Optimum Utilities Operations Report
Key Performance Indicators Monitoring and Accounting Reports

Industrial Site
Process

From VisualMesa® brochure, Courtesy of Soteica LLC, Houston, Tx
Expected Benefits and Costs

• Typical savings = 3-5% of baseline (operator-optimized) energy costs

• Typical installed cost = $500-900K

• Typical Payback << 1 yr

• Proven in dozens of Oil refineries, Chemical plants, Pulp/Paper mills (can be deemed a Best Practice)
Case Study – Operate closer to Optimum

Y axis = Deviation from Optimum = Remaining Savings Opportunity

Graphic supplied by Soteica LLC, Houston, Tx
IN CONCLUSION

• Use GCC to choose Stm Levels and Loads
• Use BPSTs in cogen mode when possible
• Condensing steam turbines are *Invariably Bad*
• Use TSSS to identify optimum CHP structure
• Use CHP models to optimize parameters
• Always optimize process demand before trying to design/optimize the CHP system
• Ability to export excess power to the Grid at a fair price is critical to optimizing energy efficiency at National scale, and minimizing global GHG emissions

🌟 with a few rare exceptions
Optimum Process Integration

It’s like a jig-saw puzzle, but well worth the effort