3. FEASIBILITY STUDY ON COGENERATION FROM 100 MW THERMAL POWER PLANT

Feasibility study was carried out at the “Heladhanavi” 100 MW thermal power plant at Puttalam, Sri Lanka.

3.1. Introduction to Heladhanavi Power Plant

“Heladhanavi” is a 100 MW power plant owned by Lakdhanavi Limited, which is a subsidiary of LTL Holdings. Heavy furnace oil having viscosity 180 mm²/s at 50 °C is use as fuel for prime movers. Electricity generated by the power plant feed to Puttalam substation at Kaladiya. Plant generates electricity at 15 kV and then steps up to 132 kV for transmission.

Plant consists of six four stroke, turbocharged, intercooled Wartsilla 18V46 diesel engines as prime movers and each generating set generate 17 MW of Electrical Power. These engines are coupled to six 21 MVA, ABB, AMG 1600 alternators.

Exhaust system of the “Heladhanavi” Power Plant was studied and analyzed. Accordingly co-generation system was proposed to the plant.

Calculation of Engine Efficiency

\[
\begin{align*}
\text{Calorific Value of HFO} & = 40616 \text{ kJ/kg} \\
\text{Energy contained in fuel 0.200 kg} & = 8123 \text{ kJ} \\
\text{Electrical O/P (1kWh)} & = 3600 \text{ kJ} \\
\text{Efficiency of the Generator} & = \frac{3600 \times 100}{8123} \\
& = 44.3%
\end{align*}
\]

This is considered as the most efficient diesel engine power plant in Sri Lanka and this has the lowest unit cost at selling, compared to other diesel engine power plants in Sri Lanka.
3.1.1. Exhaust Gas System of the Engine

Temperature of the exhaust gas : 410 °C
Exhaust gas flow rate : 30 kg/s

At the exhaust stroke of the pistons, accumulated exhaust gas in the cylinders move to the exhaust gas manifold. As we can see in the picture below, average exhaust gas temperatures at the exhaust valves of cylinders are around 425 °C. Before leaving the exhaust temperature to the environment, it drives a turbo charger. Turbocharger extracts, enthalpy and the kinetic energy of the exhaust gas.

3.1.2. Present System for Heat Recovery

Three engines are equipped with smoke tube waste heat recovery boilers and each produce saturated steam, 3000 kg/h at 7 bar pressure. Most important use of the steam is fuel heating and to maintain engine heat at engine stoppages. Power plant consumes about 2500 kg/h of steam. Because of the lower steam requirement in the plant, only one boiler puts in to operation at a time and other two boilers are in standby mode. In close proximity to Puttalam area there are no heat loads, which can be catered from the excess steam, generate from “Heladhanavi” power plant. Therefore, exhaust gas of five engines dissipate to the environment, without doing any useful work.
3.2. Cogeneration at Heladhanavi Power Plant

Heat of the exhaust gas is under-utilized and a cogeneration system can be implemented to maximize the energy utilization in exhaust gas.

Two options can be considered:

1. Expansion of current Heat Recovery System for electricity generation
2. Installation of a new Heat Recovery System

3.2.1. Expansion of current Heat Recovery System

Use three existing boilers and installation of three new boilers to the other three engines.

From existing boilers:

- Steam Availability (from 2 boilers) = 6000 kg/h = 1.67 kg/s (One boiler for process heating)
- Enthalpy of 7 bar steam = 2764 kJ/ kg
- Enthalpy of 0.5 bar condensate = 343.3 kJ/ kg
- Energy input for a steam turbine = 2420.7 kJ/kg
- For 1.67 Kgs steam = 4042.6 kW

Assume Turbine efficiency as 30%
- Turbine Output = 1.213 MW

Consider Alternator Efficiency as 97%,
- Power at the Alternator output = 1.17 MW

After installing boilers for other 3 engines,

- Turbine Power Output would be = 1.213x5/2
  = 3.032 MW

Consider Alternator Efficiency as 97%,
- Power at the Alternator output = 2.94 MW
Advantages of the system

1. Capital cost would be very low, because it uses the existing three boilers.
2. Project implementation is easy and can be completed in less time.
3. There would be no efficiency drops in turbochargers, because back pressures of the boilers would be same as the existing conditions.
4. There would be no issue with the stack corrosion, because temperature at the top of the stack is around 300 °C and it is well above the sulfur dew point.
5. Top of the stack temperature would be sufficient to maintain ambient air quality. Environmental Impact Assessment for “Heladhanavi” has considered this and proven with the dispersion model. [8]

Disadvantages of the system

1. Existing boilers were not designed to extract maximum possible heat energy. Therefore, designing an optimum boiler will generate more steam. At present, exhaust gas temperature after the boiler is around 300 °C. This can be reduced to about 200 °C, because, sulfur dew point is 170 °C. But, the back pressures of the boilers need to be studied. Back pressure has an effect on turbocharger efficiencies. Maximum allowable back pressure by Wartsilla (Engine Manufacturer) project guide is 0.03 bars. [9]

2. Present system generates saturated steam. Saturated steam contains water droplets (not 100% dry). These water droplets can damage blades of the steam turbine. Therefore, superheated steam should be used in steam turbine systems. In addition, it increases the efficiency of the steam turbine.
3.2.2. Implementation of a new steam cycle

In the proposed system, exhaust gas from all the engines flow through three stages of the heat recovery steam generator,

1. Pre-Heater
2. Steam Generator (Evaporator)
3. Super Heater

Figure 3.1: Schematic diagram of the proposed co-generation system
Heat balance for the heat recovery steam generator:

Calculations for steam capacity:

In order to maintain exhaust temperature for other stages of the HRSG, decided to maintain exhaust gas temperature above 360 °C at exit of super heater.

To maintain exhaust temperature for pre-heater, decided to maintain exhaust temperature above 260 °C (Sulfur Dioxide Dew point is 170 °C) at exit of steam generator.

Exhaust gas flow rate of one engine is 30 kg/s,
Hence, exhaust flow rate from six engines = 180 kg/s
Enthalpy deference at 25 bar, 224 °C vapor and liquid = 1841 kJ/kg

Assume efficiency of the system as 80%. This contains losses in the heat transfer (5-10%), blow down losses 2-4%, heat losses in steam system 5-10%.

Assume, steam mass flow rate as m kg/s,

\[(360-260) \times 1.005 \times 180 \times 80\% = m \times 1841\ \text{kJ/s}\]

\[m = 7.82\ \text{kg/s} = 28,152\ \text{kg/h}\]

Therefore, achievable steam generation is 28,000 kg/h.
Calculation for the stack exit temperature of the exhaust gas:

Take designed feed water temperature as 80 °C. High temperature cooling water of the engine is 90-100 °C. Therefore, feed water temperature can be maintained at 80 °C.

Energy required to heat 80 °C water to, 224 °C at 25 bar

\[ E = m \cdot C_w \cdot T \]
\[ = 7.82 \times 4.187 \times (224-80) \text{ kJ/s} \]
\[ = 4715 \text{ kW} \]

Heat balance for the economizer,

Exhaust flow rate from six engines = 180 kg/s
Specific heat of exhaust gas = 1.005 kJ/K/kg
Exhaust temperature, after the steam generator = 260 °C

\[
\frac{(180 \times 1.005 \times 260 + T_2)}{T_2} = 4715 \text{ kW}
\]

Temperature at the top of the stack, \( T_2 = 227.4 \) °C
Therefore, maintain \( T_2 \) at = 230 °C

Dew point of sulfur dioxide is 170 °C. Therefore, safety factor of 1.35 can be maintained. Exhaust gas temperature has an effect on exhaust gas dispersion, at higher temperatures gases disperse in to higher altitudes and exhaust gas dispersion is very low at low exhaust gas temperatures.
Calculation of the exhaust gas temperature at the exit of the super heater:

Superheat steam up to = 380 °C
Boiling point at 25 bar is = 224 °C
Temperature of the saturated steam = 224 °C
Enthalpy value of superheated steam at 380 °C = 3240 kJ/Kg
Enthalpy value of superheated steam at 224 °C = 2803 kJ/Kg
Consider steam dryness fraction as 0.95
Heat balance for steam heating and exhaust gas flow :

Assume efficiency of the system as 80%.

\[ 30 \times 6 \times (400 - T_1) \times 1.005 \times 0.80 = (3240 - 2803) \times 7.82 + 0.05 \times 7.82 \times 1841 \]

Exhaust gas temperature after the super heater = 370 °C

Calculation of Electrical Power output:

Enthalpy of superheated steam 25 bar at 380 °C = 3192 kJ/Kg
Enthalpy of 0.5 bar condensate = 343.3 kJ/ kg
Energy in 1 kg of steam to turbine = 2848.7 kJ/kg
Assume 1/6th of steam goes to process heating
Power available to steam turbine from steam mass flow rate 6.52 kg/s = 18.57 MW
Assume efficiency of turbine as 30%  
Alternator 97%  
Efficiency of Gear box 95%

Electrical Power Output = 5.134 MW

After considering other losses and other practical aspects, there will be a potential to generate 4 MW, which is 5.8% of total exhaust energy.

At, 0.85 power factor, alternator capacity need to be 4.7 MVA.
3.2.3. Heat balance of the plant with cogeneration

Useful energy output from cogeneration

\[
\text{per one engine} = \frac{4}{6} \text{ MW} = 0.67 \text{ MW}
\]

Effective energy output from one engine = 17.67 MW

Energy contain in the fuel feed to plant for 1s = 38.36 MW

Therefore, thermal efficiency of the plant = 46.06 %

Calculation of Exhaust Heat

- Exhaust flow rate = 30 kg/s
- Temperature after engine = 230 °C
- Ambient temperature = 30 °C
- \( C_p \) of flue gas = 1.005 kJ/kg/K
- Power of flue gas = \( mC_p\Delta T \)
  \[= 30 \times 1.005 \times 200 \text{ kJ/s} = 6030 \text{ kW}\]

Percentage of input = 15.7%

Energy dissipation through exhaust gas = 15.7 %

Heat radiated to surrounding = 1 %

Energy dissipation to Diesel generator = 46.06 %

Heat Energy dissipation to water system = 23 %

Losses through alternator and other frictional losses = 2.7 %, Losses in the secondary cycle = 11.7 %

Figure 3.2: Energy Balance for diesel engine after cogeneration
3.3. Electrical Interconnection

3.3.1. Existing System

Following is the single line diagram of the power plant. There are two 15 kV medium bus bars, bus bar A and bus bar B. Three diesel generating sets connect to bus bar A and other three connect to bus bar B. There are three LV bus bars, A, B and C. LV bus bars can be energized either form MV bus bar A or MV bus bar B.

Station consumption of the power plant is 0.8 MVA – 1.2 MVA. New Heat recovery steam system generation can be used to cater station consumption, the export from the new steam system will be = 3.5- 3.9 MVA.
Two options are considered,

1. Keep the existing electrical system and accordingly design the new cogeneration system.
2. Enhance capacity of the existing electrical system and use the maximum potential of cogeneration.

### 3.3.2. Interconnecting new cogeneration system to existing LV system

Export will be limited by 1.6 MVA transformer capacities. Therefore, electricity export has to be limited to 1.6 MVA from each transformer. Hence, total export should be limit to 3.2 MVA. Considering station consumption generation has to limit to 4 MVA and has to divide into two, 1.6 MVA each. Thus, two steam turbine generating sets are needed.

![Figure 3.4: Option 1: Interconnection to existing LV system](image-url)
Advantages of the option:
1. No need of additional investments for capacity enhancements of electrical system

Disadvantages of the option:
1. Need two generating sets, two alternators, two steam turbines – initial investment is high.
2. Does not utilize the maximum steam potential.
3. Difficulty in maintaining two sets of equipments.

3.3.3. Option 2: Interconnection to the Medium Voltage Bus bar

This option requires only one steam turbine and an alternator. Generated electricity can be exported directly to the MV bus bar through a transformer. Part of the
generated energy from steam system can be used to cater for the station consumption and the remaining power can be exported.

**Equipment ratings for this option:**

Total power of the cogeneration system is 4.7 MVA.

Therefore, capacity requirements can be identified as follows,

- Transformer  5 MVA , 400V / 15 kV
- LV breakers 5 MVA, 7500 A
- MV Breaker 5 MVA
- Cables

Advantages of the option:

1. New system is independent from the existing LV system. Therefore, able to move to a solution with maximum power generation without constraints.
2. Only one steam turbine generating set is needed.
3. Operation and maintenance will be easy.

Disadvantages of the option:

1. Additional cost for Transformers, Breakers and cables.

Best option is to go for a capacity enhancement with option 2; it will produce the maximum energy output.
3.4. Environmental Impacts

There are benefits and drawbacks to the environment.

Benefits to the Environment

1. The proposed cogeneration system will add 4MW of power to the system and will be able to maintain 80% plant factor. To generate this energy, no need to burn extra fuel. Addition of this 4 MW will reduce the generation in another thermal power plant or the same power plant.

Fuel saving:

Fuel requirement to generate 1kWh = 220 ml

Energy export for one year at 80% plant factor = 4×365×24×0.8 MWh

= 28000 MWh

Fuel saving for a year = 220 × 28000 litres/year = 6160 m³/year

This fuel will be saved for future use and this can be considered as a saving of mineral resources.

2. Addition of 4 MW will reduce the generation in another thermal power plant or in the same power plant. Therefore, CO₂ emissions from that plant get reduced.

3. Sri Lanka is eligible to sell carbon credits under Clean Development Mechanism. According to Sustainable Energy Authority, recent grid emission factor is 0.7507 t-CO₂/ MWh [10]. This value is according to combined margin calculation for first crediting period.

Therefore, CO₂ saving for total generation, 28 GWh = 21,000 t- CO₂
Price of a certified 1 t- CO₂ is 0.5 € 0.5 , as at 06th November 2013 [11].

Income from carbon trading = € 10,500 / year

**Drawbacks to the Environment**

The heat of the exhaust gas is absorbed by the new heat recovery system. Therefore, at the top of the stack, exhaust temperature reduces. If the temperature of the exhaust is high, they disperse in higher altitudes of the environment. At low temperatures, exhaust gases do not disperse into high altitudes and this creates poor ambient air quality.

In assessing the impacts of the exhaust gas on ambient air quality, “US-EPA SCREEN -3” Air dispersion model was used. The same model was used in the Environmental Impact Assessment of the power plant [8]. The model can be used to predict the ambient air quality with the proposed heat recovery system. And this will assess the required height of the stack. This computerized model is an air dispersion model, to assess the air pollution impacts of stationary sources. The model was stimulated to estimate the “worst probable short- term air pollution impacts” due to the emissions of sulfur dioxide (SO₂), Nitrogen Dioxide (NO₂) and Suspended Particulate Matter (SPM) of the proposed system. The simulation was done under “Rural” condition at all Pasquill Stability Categories with the wind speeds of 1 m/s and 3m/s, which are the minimum and the maximum wind speeds that could be used with the model for all stability classes.

The “Pasquill” Stability category was defined by Pasquill et. Al. in 1974 to describe the lowest layer of the atmosphere using wind speed, solar radiation and the time of the day.
Table 3-1: Pasquill Stability Categories

<table>
<thead>
<tr>
<th>Surface wind speed (m/s)</th>
<th>Daytime</th>
<th>Night-time conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Strong</td>
<td>Moderate</td>
</tr>
<tr>
<td>&lt; 2</td>
<td>A</td>
<td>A - B</td>
</tr>
<tr>
<td>2 - 3</td>
<td>A - B</td>
<td>B</td>
</tr>
<tr>
<td>3 - 5</td>
<td>B</td>
<td>B - C</td>
</tr>
<tr>
<td>5 - 6</td>
<td>C</td>
<td>C - D</td>
</tr>
<tr>
<td>&gt; 6</td>
<td>C</td>
<td>D</td>
</tr>
</tbody>
</table>

Ambient air quality assessment using Dispersion Model

Summary of input data for the model outputs is as follows:
The area covered : 10 km from the proposed site
Topographical Conditions: Flat Terrain
Fuel Type: Heavy Fuel Oil (1500 Sec.).

Stack Dimensions and emission information:

Stack Height: 32 m
Number of Stacks: 06 (One each per engine)
Equivalent Diameter: 3.43 m (each 1.4 m)
Stack Exit temperature:
1. Without Heat Recovery system: 633 °K
2. With proposed Heat Recovery System: 503 °K
Exhaust flow rate: 30 kg/s
NO\textsubscript{x} Emission Rate as NO\textsubscript{2}: Max. 970 ppmv @ 15% O\textsubscript{2}; (~ 278.9 g/sec).
SO\textsubscript{2} Emission Rate: Max. 780 ppmv @ 15% O\textsubscript{2} (~313 g/sec).
SPM emission Rate: Max. 100 mg/Nm\textsuperscript{3}; (~ 15.3 g/sec).
Table 3-2: Results from the dispersion model

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Wind Speed</th>
<th>Maximum one hour Concentration (µg/m³) @ Distance (km) under different Pasquill Stability Classes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>A</td>
<td>B</td>
</tr>
<tr>
<td>SO₂</td>
<td></td>
<td>Bfr. 146.8</td>
</tr>
<tr>
<td></td>
<td>1.7</td>
<td>2.5</td>
</tr>
<tr>
<td>NOₓ</td>
<td></td>
<td>Bfr. 151.6</td>
</tr>
<tr>
<td></td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>SPM</td>
<td></td>
<td>Bfr. 131.0</td>
</tr>
<tr>
<td></td>
<td>1.7</td>
<td>2.5</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>140.0</td>
</tr>
<tr>
<td></td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>7.5</td>
</tr>
<tr>
<td></td>
<td>0.98</td>
<td>1.0</td>
</tr>
</tbody>
</table>
Although the maximum predicted values are high as 177.7.6 µg/m$^3$ and 158.8 µg/m$^3$ SO$_2$ and NO$_2$ respectively, the SO$_2$ and NO$_2$ levels in Colombo with high amount of emissions from more than 295 MW (CEB : 2001) capacity HFO operated thermal power plants, large number of ships with same type of engines coming daily to the Colombo harbor and emissions from very large number of vehicles, are only 91.5 µg/m$^3$ and 67.58 µg/m$^3$ respectively, which are much lower than the predicted figures under stability classes A and E. Therefore, it appears that application of stability classes A and E is not appropriate. [8]

Table 3-3: Emission levels before and after

<table>
<thead>
<tr>
<th></th>
<th>Before</th>
<th>Aft. Cogeneration</th>
<th>µg/m$^3$</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO$_2$</td>
<td>3.2 – 72.8</td>
<td>3.7-80.1</td>
<td></td>
</tr>
<tr>
<td>NO$_2$</td>
<td>2.8 - 69.6</td>
<td>3.0- 79.3</td>
<td></td>
</tr>
<tr>
<td>SPM</td>
<td>0.15 – 3.8</td>
<td>0.18-4.7</td>
<td></td>
</tr>
</tbody>
</table>

Table 3.4 shows the average values of dispersion model outputs and they can be compared with Central Environmental Authority limits in Table 3.5. Average values for before and after cogeneration system are below the CEA limits.

Table 3-4: Average values before & after

<table>
<thead>
<tr>
<th></th>
<th>Before</th>
<th>Aft. Cogeneration</th>
<th>µg/m$^3$</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO$_2$</td>
<td>54.37</td>
<td>60.21</td>
<td></td>
</tr>
<tr>
<td>NO$_2$</td>
<td>49.16</td>
<td>57.31</td>
<td></td>
</tr>
<tr>
<td>SPM</td>
<td>2.68</td>
<td>2.92</td>
<td></td>
</tr>
</tbody>
</table>
Table 3-5: The permissible ambient air quality limits stipulated by the Central Environmental Authority of Sri Lanka (Extraordinary Gazette No. Dec. 20.1994):

<table>
<thead>
<tr>
<th>POLLUTANT</th>
<th>TIME AVERAGE</th>
<th>CONCENTRATION ($\mu g/m^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO$_2$</td>
<td>08 Hours</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>24 Hours</td>
<td>100</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>08 Hours</td>
<td>120</td>
</tr>
<tr>
<td></td>
<td>24 Hours</td>
<td>80</td>
</tr>
<tr>
<td>SPM</td>
<td>08 Hours</td>
<td>350</td>
</tr>
<tr>
<td></td>
<td>24 Hours</td>
<td>300</td>
</tr>
</tbody>
</table>

Even though there is an increase in pollutant in ambient quality, they are within limits of Central Environmental Authority. Therefore, there is no need of extending stack height.

From environmental point of view this can be identified as an environmental friendly project. It saves fuel oil for next generations and also reduces CO$_2$, SO$_x$, and NO$_x$ gases to the environment. Therefore, benefits outweigh the drawbacks of the projects.

3.5. Assessment of the Financial Feasibility

This section evaluates the financial feasibility of the proposed co-generation system. “Heladhanavi” Power Plant has the lowest unit cost in Sri Lanka. Hence, it has the lowest financial gain from cogeneration, because the value of electricity units save or sold has a lower value compared to that of other power plants. Therefore, if the project is feasible for “Heladhanavi” Power Plant, there is a higher probability for cogeneration project in other thermal oil power plants to become financially feasible.
3.5.1. Determining Installation cost (Capital Cost)

Joseph A. Orlando has introduced a model to determine installation cost of a cogeneration system. Figure 3.8 is the model introduced by him in his Cogeneration Planer’s Handbook. He has drawn installation cost per kW against capacity size (kW) of the installation.

According to the above model minimum investment cost for 4 MW plant in year 1997 is 900 $/kW and maximum is 1100$ kW.

- This can be adjusted to year 2012 cost using USCPI, United States Consumer Price Index. This was used, because most of the power purchase agreements (PPAs) in Sri Lanka use USCPI, in adjusting capacity costs according to inflation.

\[
\text{Cost for 1kW}_{\text{minimum}} \quad \text{in} \quad 2012 = 900 \times \frac{\text{USCPI}_{2012}}{\text{USCPI}_{1997}} \\
= 900 \times 231.407/160.5 \\
= $1297.60
\]
Cost for 1kW_{\text{maximum}} in 2012 = 1100 \times \frac{\text{USCPI}_{2012}}{\text{USCPI}_{1997}}
= 1100 \times 231.407/160.5
= $1585.97

Average Cost for 1kW_{\text{maximum}} = $1441

Therefore, Average Project cost = Rs. 1441 \times 4000 \times 130
= Rs. 750 Million

Therefore, Minimum Project cost = Rs. 1298 \times 4000 \times 130
= Rs. 675 Million

Therefore, Maximum Project cost = Rs. 1586 \times 4000 \times 130
= Rs. 825 Million

Considering 80\% plant factor, Annual Generation = 4000 \times 365 \times 24 \times 0.8
= 28 \text{ GWh}

According to Non Conventional Renewable Energy Tariff published by Public Utilities Commission of Sri Lanka, flat tariff for Waste Heat Recovery is Rs. 6.64.

Therefore, Revenue from cogeneration system per year = 28 \times 10^6 \times 6.64
= Rs. 186 Million

**Average Simple Pay back** = 4 years

**Maximum Simple Pay back** = 4.2 years

But, the above model was built in 1997, even though we have adjusted the installation cost to 2012, there may be deviations.

Therefore, following estimated budget was prepared to arrive to a more accurate installation cost. Prices were found from a market survey.
Table 3-6: Estimated capital cost for proposed cogeneration system

<table>
<thead>
<tr>
<th>Equipment / Description</th>
<th>Cost (US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HRSG Boiler</td>
<td>855,000.00</td>
</tr>
<tr>
<td>Water Preheater</td>
<td>27,000.00</td>
</tr>
<tr>
<td>Exhaust ducts</td>
<td>36,000.00</td>
</tr>
<tr>
<td>Automatic Blow down with TDS controller and blow down flash vessel tank</td>
<td>27,750.00</td>
</tr>
<tr>
<td>Four Sets of Sample Coolers</td>
<td>13,500.00</td>
</tr>
<tr>
<td>Aerator with 20Min Storage Tank, complete with Steam Pressure Control Valve Station, Water Flow Control Valve Station, Level Transmitter, Water Temp transmitter, etc…</td>
<td>54,000.00</td>
</tr>
<tr>
<td>Two Sets of HP &amp; LP Chemical Dosing Pumps with SS Storage Tanks &amp; Stirrers</td>
<td>27,900.00</td>
</tr>
<tr>
<td>FOUR Sets of Sonic Soot Blowers(Horne) with Timer &amp; Control Panel</td>
<td>27,000.00</td>
</tr>
<tr>
<td>Three Element Drum Level Controller with Electro-Pneumatically Controlled Feed Water Control Station</td>
<td>27,000.00</td>
</tr>
<tr>
<td>Steam Pressure Transmitter and Pressure Controller</td>
<td>18,000.00</td>
</tr>
<tr>
<td>PLC with SCADA Operating System for Boiler, Chiller &amp; Turbine Generator</td>
<td>855,000.00</td>
</tr>
<tr>
<td>Condenser with Cooling Water Circulation Pumps of 240 m3/Hr (40 HP) X 3 Sets (Two Working + One Standby)</td>
<td>30,000.00</td>
</tr>
<tr>
<td>Mech., Electrical, Instrumentation, Refractory &amp; Insulation engineering &amp; Site labor with Supervision entire Steam-Power Co-Generation Plant at site</td>
<td>225,000.00</td>
</tr>
<tr>
<td>Steam Turbine</td>
<td>1,192,500.00</td>
</tr>
<tr>
<td>Transformer 415/15000V, 5 MVA</td>
<td>150,000.00</td>
</tr>
<tr>
<td>Alternator 5 MVA, 415 V synchronous</td>
<td>500,000.00</td>
</tr>
<tr>
<td>Total installation Cost US $</td>
<td>4,515,650.00</td>
</tr>
<tr>
<td>Total installation Cost Rs.</td>
<td>587 millions</td>
</tr>
</tbody>
</table>

According to this estimation, simple pay back = **3.15 years**
This is very much favorable in an electricity power project.

3.5.2. Profit and Loss Statement for proposed cogeneration system

The operation period of the power plant was considered as seven years. Operation and Maintenance cost of the cogeneration system was considered same as for the average operation and maintenance cost at present and inflation was considered as 10%. The life times of the equipment was considered as fifteen years and depreciated the value equally for the life time. Income tax value, considered as 30%.

Cash values are in MRs

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy supplied</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>28</td>
<td>28</td>
</tr>
<tr>
<td>Tariff (Rs./kWh)</td>
<td>0.00%</td>
<td>6.64</td>
<td>6.64</td>
<td>6.64</td>
<td>6.64</td>
<td>6.64</td>
<td>6.64</td>
<td>6.64</td>
</tr>
<tr>
<td>Revenue</td>
<td>186</td>
<td>186</td>
<td>186</td>
<td>186</td>
<td>186</td>
<td>186</td>
<td>186</td>
<td>186</td>
</tr>
<tr>
<td>O&amp;M cost (Rs./kWh)</td>
<td>10%</td>
<td>0.50</td>
<td>0.55</td>
<td>0.61</td>
<td>0.67</td>
<td>0.73</td>
<td>0.81</td>
<td>0.89</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>14.00</td>
<td>15.40</td>
<td>16.94</td>
<td>18.63</td>
<td>20.50</td>
<td>22.55</td>
<td>24.80</td>
<td></td>
</tr>
<tr>
<td>Finance cost</td>
<td>71.8</td>
<td>55.9</td>
<td>39.9</td>
<td>23.9</td>
<td>8.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Profit before tax</td>
<td>60.9</td>
<td>75.5</td>
<td>89.9</td>
<td>104.2</td>
<td>118.3</td>
<td>124.2</td>
<td>122.0</td>
<td></td>
</tr>
<tr>
<td>Tax (0% and 30%)</td>
<td>30%</td>
<td>18.3</td>
<td>22.7</td>
<td>27.0</td>
<td>31.3</td>
<td>35.5</td>
<td>37.3</td>
<td>36.6</td>
</tr>
<tr>
<td>Profit After Tax</td>
<td>42.7</td>
<td>52.9</td>
<td>63.0</td>
<td>72.9</td>
<td>82.8</td>
<td>87.0</td>
<td>85.4</td>
<td></td>
</tr>
</tbody>
</table>

3.5.3. Cash flow Statement for proposed cogeneration system

Debt to Equity ratio was assumed as 4:1 and 17% interest loan for a five year period was considered. The life times of the equipment was considered as fifteen years and the value was depreciated equally throughout the life time.
Cash values are in Million Rupees.

Table 3-8: Cash flow Statement for proposed cogeneration system

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>469.6</td>
<td>375.68</td>
<td>281.76</td>
<td>187.84</td>
<td>93.92</td>
<td>0</td>
</tr>
<tr>
<td>1</td>
<td>71.8</td>
<td>55.9</td>
<td>39.9</td>
<td>23.9</td>
<td>8.0</td>
<td>0.0</td>
</tr>
<tr>
<td>2</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>3</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>4</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>5</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>93.9</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Project Internal Rate of Return is 21.6%, this is higher than the treasury bill rates and the inflation. But, lower than normal power projects. And this project is involved with higher risk factors. Therefore, there is a risk related to the project and sensitivity analysis need to be carried out.

Table 3-9: Proposed Loan schedule for cogeneration system

<table>
<thead>
<tr>
<th>Project Cost</th>
<th>587 MRs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt Equity Ratio</td>
<td>4:1</td>
</tr>
<tr>
<td>Loan</td>
<td>469.6 MRs</td>
</tr>
<tr>
<td>Equity</td>
<td>117.4 MRs</td>
</tr>
<tr>
<td>Loan period</td>
<td>5 years</td>
</tr>
<tr>
<td>Interest rate</td>
<td>17%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>469.6</td>
<td>375.68</td>
<td>281.76</td>
<td>187.84</td>
<td>93.92</td>
<td>0</td>
</tr>
<tr>
<td>1</td>
<td>71.8</td>
<td>55.8824</td>
<td>39.916</td>
<td>23.9496</td>
<td>7.9832</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>93.9</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
</tr>
<tr>
<td>3</td>
<td>93.9</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
</tr>
<tr>
<td>4</td>
<td>93.9</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
</tr>
<tr>
<td>5</td>
<td>93.9</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
<td>93.92</td>
</tr>
</tbody>
</table>

Equity IRR 21%
3.5.4. Risk Assessment and Sensitivity Analysis

There are several risks that are related to cogeneration projects in diesel engine power plants. They can be identified as follows,

1. The main risk is about the project life time, now most of the power plants have come to verge of their power purchase agreements. Still discussions are going on to extend the agreements. Therefore, there is a high risk on the project period.

2. Capital cost can deviate from the estimation.

3. Estimated Operation and Maintenance cost can deviate from estimated values.

4. Tariff can vary depending on Public Utilities commission’s decisions and renegotiation of power purchase agreements.

5. Dispatch of diesel power plants may get reduced with commissioning of new coal power stations.

Table 3-10: Sensitivity Analysis

<table>
<thead>
<tr>
<th>Project Parameter</th>
<th>Project IRR</th>
<th>Equity IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation period</td>
<td>5 years 13.7%</td>
<td>loss</td>
</tr>
<tr>
<td></td>
<td>10 years 26.4%</td>
<td>32%</td>
</tr>
<tr>
<td>Installation cost</td>
<td>750 million 7.8%</td>
<td>4%</td>
</tr>
<tr>
<td></td>
<td>825 million 3%</td>
<td>loss</td>
</tr>
<tr>
<td>O&amp; M Cost</td>
<td>Rs.0.75 18.4%</td>
<td>16%</td>
</tr>
<tr>
<td>Tariff</td>
<td>Rs. 20 (Thermal oil power plant tariff) 129.4 %</td>
<td>221%</td>
</tr>
<tr>
<td></td>
<td>Rs. 10 52.9%</td>
<td>68%</td>
</tr>
<tr>
<td></td>
<td>Rs. 15 93.8%</td>
<td>145%</td>
</tr>
<tr>
<td>Plant Factor</td>
<td>70% 14.9%</td>
<td>12%</td>
</tr>
</tbody>
</table>

From the Table 3.10, sensitivity analysis, it is clear that project is very sensitive to above risks.