**CHAPTER III**

**ENGINEERING ECONOMIC ANALYSIS**

This chapter presents the economic analysis of the proposed 500 MW Coal-Fired Power Plant in Brgy. Lumaniag, Lian, Batangas. The analysis includes the project costing, depreciation, return of investment, sensitivity analysis and other computations involved in the economic aspects of the proposed power plant.

**Key Assumptions**

A steam power plant is used to generate electricity by the use of several components such as steam turbine, boiler, condenser and feedwater heater. This electricity is distributed to chosen utilities for further distribution in some municipalities. For the proposed power plant, several assumptions were made to calculate the economic analysis of the design.

Coal has the largest percentage of source of fuel for power plants having 42.8% of the total percentage. This is the reason why the chosen fuel of the proposed power plant is coal since it also has a cheaper price compared to oil. Many coal-fired power plants have a life span of 30 years. For the proposed power plant, it is assumed to have a 25-year operating life with maintenance and repair annually. It is also assumed that the proposed power plant will operate for 365 days except for some problems that may be encountered in the operation. The assumed discount rate is 5% which is used to calculate the capital recovery factor. For the capacity factor of steam power plants, it is assumed to be 54.6% based on the performance of coal fired power plants operating actively. For the economic analysis, the capital expenditures is calculated by getting the total of the equipment cost, miscellaneous cost, building cost, electrical cost, excavation and foundation cost, land cost and instrumentation and control cost. For the annual operating expenditures, it is assumed to include the fuel cost, labor, maintenance and repair, supervision, supplies and operating taxes. The service facilities cost is the sum of maintenance and repair cost and supplies. The equipment cost of equipment varies in every design since the number of closed feedwater heater is increasing. Case 3 which is the most efficient design has 7 closed feedwater heater. From this, Case 3 became the basis of the costing for the economic analysis of the proposed power plant.

Furthermore, the rate of return which is the profit on an investment over the assumed operating life of 25 years is assumed to be 33.90% based on the assumptions and calculations made. The depreciation rate is 4% which is calculated using the 25-year operating life. An analysis was also made to assume and understand the effect of construction delay, reduce of power generation by 10%, increase and drop of fuel price by 10% to the internal rate of return. It is calculated from the assumed data that the average effect of the independent variables to dependent variables is 3%. Moreover, the expected length of time to recover the initial investment was calculated by dividing the amount of cash outlay at the assumed year of 2022 by the net cash inflow which is assumed to be the same every year. The assumed payback period of the proposed power plant is 4 2/5 years or 4 years and 5 months. Likewise, assumptions were made in order to forecast the future performance of the proposed coal-fired power plant.

**Power Demand Analysis**

The proposed coal-fired power plant has a capacity of 500 MW to be located at Lian, Batangas. The electricity that will be generated will be transmitted to the Luzon Grid of the National Grid Corporation of the Philippines (NGCP).

According to Department of Energy, the forecasted total System Peak Demand for Luzon is 12,285 MegaWatts (MW) to occur in May 2020 which is an increase of 8.3% from the actual 2019 peak demand of 11,344 MW which occurred in the dry season months of the country. In order to stabilize the grid in the coming year, the Luzon Grid needs around 4% of the peak demand which is around 491 MW in regulating power. As the consumers shift in the way of the usage of power, it needs to maintain the power equivalent in order to support the grid in case of emergencies.

The table below shows the actual peak demand of 2019 and Forecast Peak Demand of 2020 in the Luzon, Visayas and Mindanao grids.

**Table 15.0**

**Actual and Forecast Peak Demand**

|  |  |  |
| --- | --- | --- |
| GRID | 2019 Actual Peak Demand | 2020 DOE Forecast Peak Demand |
| Luzon | 11,344 MW (June) | 12,285 MW (May) |
| Visayas | 2,224 MW (May) | 2,419 MW (May) |
| Mindanao | 2,103 MW (May) | 2,278 MW (December) |

*Source: ngcp.ph*

From the table above, it can be seen that there is an increase in the demand of the consumers since the way people use the electricity changer. The Department of Energy forecasted an increase of 8.3% of the 2019 Actual Peak Demand which is about 941 MW. In addition, electricity demand goes higher in dry season months such as May and June. For the 2020 Forecast Peak Demand of the Department of Energy, it is observed that the Luzon, Visayas and Mindanao Grids will have a total peak demand of 16,982 MW.

The table below presents the electric generation and consumption of different types of distribution utilities in Luzon, Visayas and Mindanao. The power consumption is listed by sector which includes residential, commercial, industrial and other sectors.

**Table 16.0**

**2018 Electric Generation and Consumption in MWh**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Type of Distribution Utilities | Luzon | Visayas | Mindanao | Philippines |
| Power Consumption by Sector | | | | |
| Residential | 20,557,265 | 3,863,595 | 3,839,904 | 28,260,764 |
| Commercial | 20,691,045 | 1,704,677 | 1,620,548 | 24,016,270 |
| Industrial | 19,352,877 | 3,978,020 | 4,256,451 | 27,587,348 |
| Others | 940,124 | 1,285,120 | 527,474 | 2,752,719 |
| Total Sales | 61,541,312 | 10,831,413 | 10,244,377 | 82,617,102 |
| Own-Use | 5,668,573 | 1,485,306 | 987,157 | 8,141,036 |
| System Loss | 6,293,025 | 1,175,228 | 1,538,327 | 9,006,580 |
| Total Consumption | 73,502,911 | 13,491,947 | 12,769,861 | 99,764,718 |

*Source: doe.gov.ph*

According to the table above, the consumption of Luzon grid soared to 73,502,911 MWh for 2018 wherein residential sector contributed 82.15% of the total power consumption of the sectors. The industrial sector has been increasing since a lot of programs in the industry are continuously driven. Comparing the 2017 generation, the residential sector marks a growth of 5.5% in 2018 from 4.5% in 2017.

The table below shows the system peak demand in MW of the three grids. The data gathered is around the year of 2018 and listed by month showing which time do consumers have the highest demand of electricity.

**Table 17.0**

**2018 Monthly System Peak Demand in MW**

|  |  |  |  |
| --- | --- | --- | --- |
| Month | Luzon | Visayas | Mindanao |
| January | 9,213 | 1,892 | 1,665 |
| February | 9,579 | 1,913 | 1,704 |
| March | 9,936 | 1,956 | 1,729 |
| April | 10,539 | 2,044 | 1,781 |
| May | 10,750 | 2,053 | 1,847 |
| June | 10,876 | 2,010 | 1,741 |
| July | 9,996 | 1,972 | 1,762 |
| August | 9,843 | 2,015 | 1,821 |
| September | 10,035 | 1,954 | 1,794 |
| October | 10,346 | 2,026 | 1,835 |
| November | 10,088 | 1,980 | 1,833 |
| December | 9,987 | 2,020 | 1,853 |
| MAX | 10,876 | 2,053 | 1,853 |

*Source: doe.gov.ph*

From the table above, it shows that Luzon and Visayas grid has the highest system peak demand in dry months. In Luzon, the system peak demand is seen in the month of June which has 10,876 MW on which the country’s temperature is at its maximum while the month of January has the lowest system peak demand of 9,213 MW. In Visayas, the highest peak demand was experienced in the month of May at 2,053 MW while in Mindanao, the month of December experienced a highest peak demand of 1,853 MW.

Upon observing, the demand of the consumers has been continuously increasing as the temperature in the country is changing. The proposed design of the coal-fired power plant has a capacity of 500 MW which will be transmitted to Luzon grid of the National Grid Corporation of the Philippines for further distribution.

**Power Demand and Supply Balance**

In the Philippines, power demand of consumers in different sectors such as residential, commercial and industrial has been increasing rapidly. Emergencies in Luzon grid are also experienced in the year 2019 that cause power interruptions in some areas of Luzon. In order to stabilize the grid, increasing demand of electricity must be regulated to avoid brownouts.

Below is the list of sources of fuel that are used in power generation in the year 2018. Power generation is in GWh unit.

**Table 18.0**

**2018 Power Generation by Source in GWh**

|  |  |
| --- | --- |
| **Source** | **Power Generation** |
| Coal | 51,932 |
| Oil-Based | 3,173 |
| Combined Cycle | 522 |
| Diesel | 2,505 |
| Gas Turbine | 0 |
| Oil Thermal | 145 |
| Natural Gas | 21,334 |
| Renewable Energy | 23,326 |
| Geothermal | 10,435 |
| Hydro | 9,384 |
| Biomass | 1,105 |
| Solar | 1,249 |
| Wind | 1,153 |
| TOTAL | 99,765 |

*Source: doe.gov.ph*

From the table above, it can be observed that coal dominated the power generation in the Luzon grid with 51,932 GWh which is about 52.05% of the total power generated. Some of the sources include oil based that may be combined cycle, diesel, gas turbine and oil thermal, natural gas and renewable energies such as geothermal, hydro, biomass, solar and wind. The total generated power in 2018 was 99,765 GWh.

Below is the table of summary for the power generation in Luzon, Visayas and Mindanao grid in the year 2018.

**Table 19.0**

**2018 Summary of Power Generation by Grid in GWh**

|  |  |
| --- | --- |
| Grid | Power Generated |
| Luzon | 72,728 |
| Visayas | 14,266 |
| Mindanao | 12,770 |
| TOTAL | 99,765 |

*Source: doe.gov.ph*

In Region IV-A, there are eight (8) distribution utilities excluding MERALCO which includes QUEZELCO II, BATELEC II, FLECO, QUEZELCO I, BATELEC I, FBPC and IEC. The table below shows the peak demand in some distribution utilities in Region IV-A.

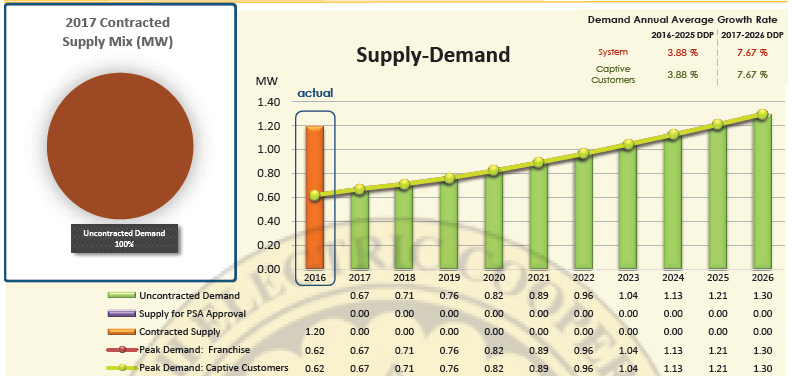
**Table 20.0**

**Region IV-A Peak Demand**

|  |  |
| --- | --- |
| Distribution Utility | Peak Demand (MW) |
| BATELEC I | 57.43 |
| BATELEC II | 136.00 |
| FBPC | 9.88 |
| IEC | 4.06 |
| TOTAL | 207.37 |

*Source: doe.gov.ph*

The table above shows that BATELEC II is the distribution utility in the listed four (4) distribution utilities which has the highest peak demand at 136 MW. The total peak demand of the listed distribution utilities is 207.37 MW. The figure below shows the supply-demand forecasted for 2016 to 2026.

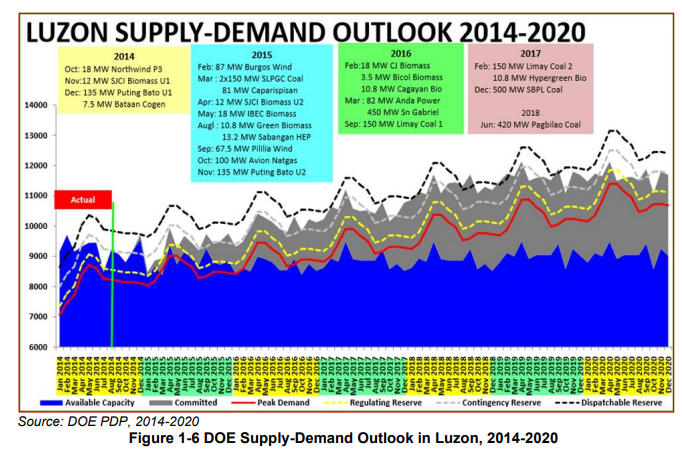


**Figure 22.** Batangas II Electric Cooperative Inc. (BATELEC II) Supply-Demand

The figure above shows the increase of demand of captive customers in the following years. For the demand annual average growth rate forecasted in 2017-1016, the system and captive customers have 7.67%. for the planning horizon, BATELEC II forecasted an AAGR of 7.67% peak demand for some areas. In terms of energy sales, BATELEC II sold 1,111.63 MWh in 2016. Over the 10-year planning period, the annual average energy sales are projected to grow by 7.50% from 1,288.20 MWh to 2,284 MWh in 2026.

According to Department of Energy, the forecasted peak demand in Region IV-A in the year 2020 is 347.65 MW equivalents to 2.03% of the total peak demand in Luzon. Furthermore, it is observed that the peak demand is increasing continuously from 347.65 MW in 2020 to 421.57 MW in 2025 which is 21.26% of the present peak demand.

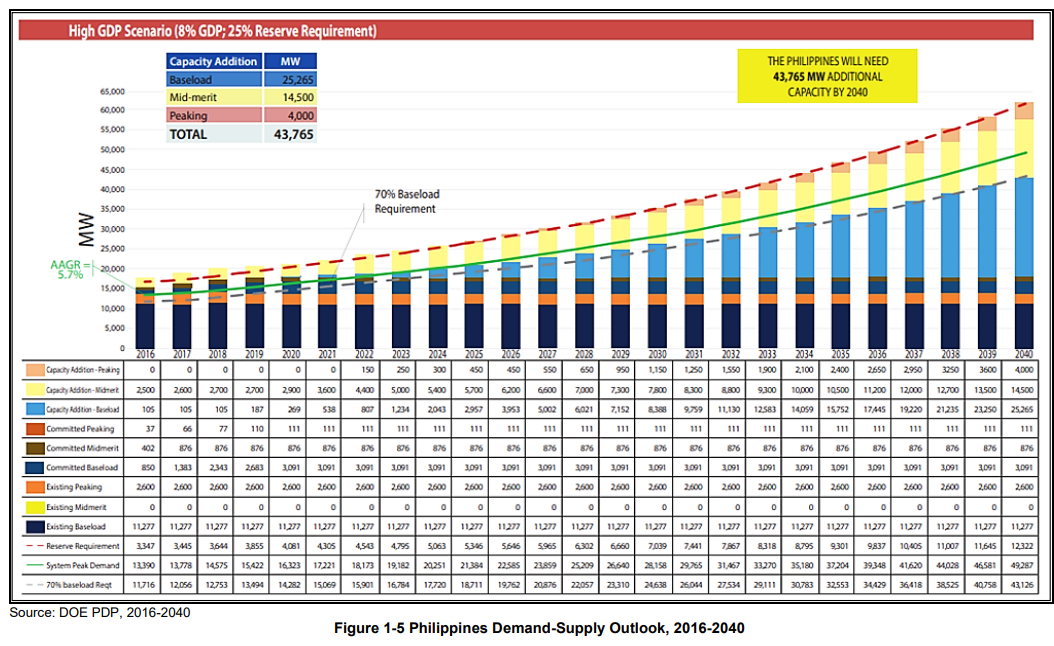
For the Luzon Supply-Demand data, the figure below from Department of Energy shows the outlook for the year 2014-2020. The figure also presents the available capacity, committed, peak demand, regulating reserve, contingency reserve and dispatchable reserve.



**Figure 23. Luzon Supply Demand Outlook for 2014-2020**

The figure above shows the supply-demand outlook on Luzon for the year 2014-2020. For each year, the graph shows the comparison of the available capacity and the peak demand on each year in Luzon. Based on the figure above, the highest peak demand within the time frame is on April and May 2020 with approximately 11,000 MW. The available capacity on the said months is approximately 9,000 MW and the committed capacity is approximately 12,000 MW.

Figure 23 shows the demand capacity for the year 2016-2040 and the capacity addition in MW for baseload, mid-merit and peaking. Included also in the graph are the capacity addition, committed peaking, committed baseload, existing peaking and system peak demand.



**Figure 24. Philippines Demand-Supply Outlook for 2016-2040**

The figure above shows that in the coming years, there will be a large increase of peak demand in the country which is forecasted until year 2040. According to the graph, the Philippines will need 43,765 MW additional capacity by 2040. This is the total capacity which is from the baseload with25,265 MW, mid-merit with14,500 MW and peaking with 4,000 MW.

**Plant Capacity Factor**

The capacity factor of the proposed coal-fired power plant is calculated by getting the ratio of the actual energy produced and the maximum energy produced on the same period. Actual energy is first determined by multiplying the average load and the operating hours per year. For the average load, it is obtained through the load factor and peak load demand. Load factor is assumed based on the Philippines Demand-Supply Outlook for 2016-2040.

**Project Cost**

For the proposed 500 MW coal-fired power plant, the total costing is presented in the summary below. Included are the installed capacity, capacity factor and the expected operating years of the proposed power plant.

**Table 21.0**

**Project Costing Summary**

|  |  |  |
| --- | --- | --- |
|  |  |  |
| installed capacity | [MW] | 500 |
| capacity factor |  | 51.39 |
| Energy | GWh/year | 2250.75 |
| cost/kW | [Php/kW] | 9.80 |
| capital cost | [Php] | 137,374,300,836.88 |
| Life | Years | 25 |
| discount rate |  | 0.05 |
| Capital recovery factor |  | 0.070952457 |
| Annual capacity cost | PHP | 11,771,314,380.02 |
| Fixed O&M | PHP | 1,307,923,820.00 |
| total fixed cost | Php | 5,220,223,431.80 |
| Fixed cost/kWh | [Php /kWh] | 10,440.45 |
| Variable cost/kWh | [Php /kWh] | 1,307.92 |
| LCOE | [Php /kWh] | 4.36 |

Based from the table above, the proposed power plant with an installed capacity of 500 MW will have a capital cost of approximately Php 137,374,300,836.88. The fixed operating and maintenance cost of the power plant are also presented in the table for the expected operating life of 5 years.

**Depreciation**

Depreciation deals with the monetary value which decreases over time due to use of the purchased equipment, instrumentation and control, service facilities and other miscellaneous aspects. Basically, it represents the method of showing the allocating cost of equipment over its service life.

Below is the table showing the depreciation cost for Design Option 1 of the proposed power plant.

**Table 22.0**

**Depreciation Cost for Design Option 1**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Book Value (Php)** | **Salvage Value** | **Service Life (yrs)** | **Depreciation (BV-SV)/SL** |
| Purchased Equipment | 73,370,087,000.00 | 934,803,480.00 | 25 | 2,817,411,340.80 |
| Instrumentation and Control | 14,674,017,400.00 | 586,960,696.00 | 25 | 563,482,268.16 |
| Service Facilities | 2,043,425,452.09 | 81,737,018.08 | 25 | 78,467,537.36 |
| Capital Cost | 134,845,568,406.88 | 5,393,822,736.28 | 25 | 5,178,069,826.82 |
| Miscellaneous | 7,337,008,700.00 | 293,480,348.00 | 25 | 281,741,134.08 |
| Total | | | | 8,919,172,107.22 |

The table above shows the total depreciation cost for case 1 with five (5) regenerative processes. The depreciation cost of the purchased equipment, instrumentation and control, service facilities, capital cost and miscellaneous is Php 8,919,172,107.22 for a service life of 25 years.

Table 22.0 below presents the depreciation cost for design option 2 which has an efficiency of 34.21%.

**Table 23.0**

**Depreciation Cost for Design Option 2**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Book Value (Php)** | **Salvage Value** | **Service Life (yrs)** | **Depreciation (BV-SV)/SL** |
| Purchased Equipment | 73,830,694,000.00 | 2,953,227,760.00 | 25 | 2,835,098,649.60 |
| Instrumentation and Control | 14,766,138,800.00 | 590,645,552.00 | 25 | 567,019,729.92 |
| Service Facilities | 2,011,629,915.40 | 80,465,196.62 | 25 | 77,246,588.75 |
| Capital Cost | 135,688,479,216.88 | 5,427,539,168.68 | 25 | 5,210,437,601.93 |
| Miscellaneous | 7,383,069,400.00 | 295,322,776.00 | 25 | 283,509,864.96 |
| Total | | | | 8,973,312,435.16 |

From the table above, the total depreciation cost for design option 2 is Php 8,973,312,435.16. This includes the depreciation of the purchased equipment, instrumentation and control, service facilities, capital cost and miscellaneous in an operating life of 25 years.

The table below shows the total depreciation cost for design option 3 which has the highest efficiency among the three designs.

**Table 24.0**

**Depreciation Cost for Design Option 3**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Book Value (Php)** | **Salvage Value** | **Service Life (yrs)** | **Depreciation (BV-SV)/SL** |
| Purchased Equipment | 74,751,908,000.00 | 2,990,076,320.00 | 25 | 2,870,473,267.20 |
| Instrumentation and Control | 14,950,381,600.00 | 598,015,264.00 | 25 | 574,094,653.44 |
| Service Facilities | 1,966,505,780.31 | 78,475,429.20 | 25 | 75,336,412.03 |
| Capital Cost | 137,374,300,836.88 | 5,494,972,033.48 | 25 | 5,275,173,152.14 |
| Miscellaneous | 7,475,190,800.00 | 299,007,632.00 | 25 | 287,047,326.72 |
| Total | | | | 9,082,124,811.53 |

Table 24.0 shows the depreciation values for design option 3 of the purchased equipment, instrumentation and control, service facilities, capital cost and other miscellaneous costs. It also presents the book value, salvage value and depreciation of the purchased equipment and other expenses with service life of 25 years. The total depreciation of the proposed power plant equipment and facilities amount to Php 9,082,124,811.53.

**Return of Investment**

For the assumed service life of 25 years, it is important to know the return of the investment at the start of the operation. Return of investment presents the gain or loss on an investment usually expressed as a percentage which is sometimes used for financial decisions.

Below is the table showing the summary of the calculation for return of investment for design option 1.

**Table 25.0**

**Return of Investment for Design Option 1**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Year** | **Period** | **TCl** | **Net Income After Tax** | **ROI** |
|  | **(Php)** | **(Php)** | **(%)** |
| 2022 | 2 | 134,845,568,406.88 | 30,663,447,287.48 | 22.74% |
| 2023 | 3 | 104,182,121,119.39 | 30,663,447,287.48 | 29.43% |
| 2024 | 4 | 73,518,673,831.91 | 30,663,447,287.48 | 41.71% |
| 2025 | 5 | 42,855,226,544.42 | 30,663,447,287.48 | 71.55% |
| 2045 | 25 | 570,413,719,205.25 | 30,663,447,287.48 | 5.38% |
|  |  |  | **Average** | 34.16% |

The table above shows that for a period of 25 years, the return of investment for design option 1 has an average of 34.16%. For design option 2, the table below shows its summary of return of investment for 25 years of operation.

**Table 26.0**

**Return of Investment for Design Option 2**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Year** | **Period** | **TCl** | **Net Income After Tax** | **ROI** |
|  | **(Php)** | **(Php)** | **(%)** |
| 2022 | 2 | 135,688,479,216.88 | 30,854,220,507.60 | 22.74% |
| 2023 | 3 | 104,834,258,709.27 | 30,854,220,507.60 | 29.43% |
| 2024 | 4 | 73,980,038,201.67 | 30,854,220,507.60 | 41.71% |
| 2025 | 5 | 43,125,817,694.07 | 30,854,220,507.60 | 71.54% |
| 2045 | 25 | 573,958,592,457.99 | 30,854,220,507.60 | 5.38% |
|  |  |  | **Average** | 34.16% |

Based on the table above, there is a small difference between the average return of investment between design option 1 and design option 2 since only one closed feedwater heater was added in the design. The average ROI of design option 2 is 34.16%.

The table below shows the summary of calculation of return of investment for design option 3 which includes the TCI, net income after tax and average return of investment.

**Table 27.0**

**Return of Investment for Design Option 3**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Year** | **Period** | **TCl** | **Net Income After Tax** | **ROI** |
|  | **(Php)** | **(Php)** | **(%)** |
| 2022 | 2 | 137,374,300,836.88 | 31,152,685,619.98 | 22.68 |
| 2023 | 3 | 106,221,615,216.89 | 31,152,685,619.98 | 29.33 |
| 2024 | 4 | 75,068,929,596.91 | 31,152,685,619.98 | 41.50 |
| 2025 | 5 | 43,916,243,976.93 | 31,152,685,619.98 | 70.94 |
| 2045 | 25 | 579,137,468,422.69 | 31,152,685,619.98 | 5.38 |
|  |  |  | **Average** | 33.96 % |

Table 27.0 presents the return of investment for design option 3 of the proposed power plant in a service life of 25 years. It shows the TCI, net income after tax and rate of investment with the corresponding period of year. The average return of investment is 33.96 %.

**Payback Period**

For the proposed power plant, it is important to know the amount of time it will take to recover the cost on the initial investment. Payback period refers to the investment divided by the annual cash flow. The shorter the payback period, the more efficient and desirable the investment is.

Below is the table showing the summary of calculation for payback period for design option 1 of the proposed power plant.

**Table 28.0**

**Payback Period for Design Option 1**

|  |  |  |  |
| --- | --- | --- | --- |
| **Year** | **Net Income after** | **TCI** | **Depreciation** |
| **Tax (Php)** | **(Php)** | **(Php)** |
| 2022 | 30,663,447,287.48 | 134,845,568,406.88 | 125,926,396,299.65 |
| 2023 | 30,663,447,287.48 | 104,182,121,119.39 | 117,007,224,192.43 |
| 2024 | 30,663,447,287.48 | 73,518,673,831.91 | 108,088,052,085.20 |
| 2025 | 30,663,447,287.48 | 42,855,226,544.42 | 99,168,879,977.98 |
| Average | 30,663,447,287.48 | 88,850,397,475.65 | 112,547,638,138.82 |
| **Payback Period** | **4.39759976 approximately 4 years and 5 months** | | |

From the table above, the estimated period of payback for design option 1 is approximately 4 years and 5 months or 5 years after the operation of the proposed power plant.

The table below presents the payback period for design option 2 which has an efficiency of 34.21%.

**Table 29.0**

**Payback Period for Design Option 2**

|  |  |  |  |
| --- | --- | --- | --- |
| **Year** | **Net Income after** | **TCI** | **Depreciation** |
| **Tax (Php)** | **(Php)** | **(Php)** |
| 2022 | 30,854,220,507.60 | 135,688,479,216.88 | 126,715,166,781.72 |
| 2023 | 30,854,220,507.60 | 104,834,258,709.27 | 117,741,854,346.56 |
| 2024 | 30,854,220,507.60 | 73,980,038,201.67 | 108,768,541,911.40 |
| 2025 | 30,854,220,507.60 | 43,125,817,694.07 | 99,795,229,476.24 |
| Average | 30,854,220,507.60 | 89,407,148,455.47 | 113,255,198,128.98 |
| **Payback Period** | **4.39772832 approximately 4 years and 5 months** | | |

Since only one closed feedwater heater was added in design option 1, the payback period of option 1 and option 2 has small difference in time. The payback period for design option 2 is approximately 4 years and 5 months or 5 years also.

The summary of calculation for design option 3 is shown on the table below which includes the net income after tax, TCI and depreciation costs with the respective years of operation.

**Table 30.0**

**Payback Period for Design Option 3**

|  |  |  |  |
| --- | --- | --- | --- |
| **Year** | **Net Income after** | **TCI** | **Depreciation** |
| **Tax (Php)** | **(Php)** | **(Php)** |
| 2022 | 31,152,685,619.98 | 137,374,300,836.88 | 128,292,176,025.35 |
| 2023 | 31,152,685,619.98 | 106,221,615,216.89 | 119,210,051,213.82 |
| 2024 | 31,152,685,619.98 | 75,068,929,596.91 | 110,127,926,402.29 |
| 2025 | 31,152,685,619.98 | 43,916,243,976.93 | 101,045,801,590.76 |
| Average | 31,152,685,619.98 | 90,645,272,406.90 | 114,668,988,808,06 |
| **Payback Period** | **4.40970973 approximately 4 years and 6 months** | | |

Table 30.0 presents the length of time required to recover the initial investment for design option 3 of the proposed power plant. The table includes the net income after tax, TCI and depreciation in four year and the average. The payback period is 4 years and 6 months.

**Sensitivity Analysis**

In the proposed power plant, it is expected to encounter several situations that may affect the performance of generating electricity. Sensitivity analysis determines how independent variables such as construction delay and increase in fuel price affect the dependent variable such as the internal rate of return.

Below is the table showing the summary of the calculation for sensitivity analysis for design option 1 of the proposed power plant.

**Table 31.0**

**Sensitivity Analysis for Design Option 1**

|  |  |  |  |
| --- | --- | --- | --- |
| Particular | Change | ENPV | EIRR |
| Base case |  | PHP | % |
| Construction delay | 1 year | 308,996,785,412.84 | 3.372421876 |
| Reduce of Power Generation by 10% | 10% | 309,230,414,026.56 | 3.375547085 |
| Increase of Fuel Price by 10% | 10% | 269,859,457,308.20 | 2.813948576 |
| Drop of fuel price by 10% | 10% | 322,038,182,780.97 | 3.543496793 |

The calculation results from the table above shows that for a construction delay, there will be an approximately 4% of EIRR which is the same as decreasing of fuel price and power generation by 10%.

**Graphical Representation**

**CASE 1.** Reduce of Power Generation by 10%

The first case for the analysis is the reduction of power generation by 10% in the span of 25 years. The graph below shows the breakeven point of design option 1 for case 1.

**Figure 25.** Break-Even Graph (Design Option 1/ Case 1)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 1 in the reduction of 10% in the power generation. The intersection of the two factors is the break-even point which is on the 4.75 year of operation.

**CASE 2.** Increase of fuel price by 10%

The second case for the analysis is the increase of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 1 for case 2.

**Figure 26.** Break-Even Graph (Design Option 1/ Case 2)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 1 in the increase of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 4.25 year of operation.

**CASE 3.** Drop of fuel price by 10%

The third case for the analysis is the drop of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 1 for case 3.

**Figure 27.** Break-Even Graph (Design Option 1/ Case 3)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 1 in the drop of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.

The table below presents the sensitivity analysis for design option 2 of the proposed power plant.

**Table 32.0**

**Sensitivity Analysis for Design Option 2**

|  |  |  |  |
| --- | --- | --- | --- |
| Particular | Change | ENPV | EIRR |
| Base case |  | PHP | % |
| Construction delay | 1 year | 310,919,214,786.39 | 3.372301 |
| Reduce of Power Generation by 10% | 10% | 308,924,628,371.85 | 3.345693116 |
| Increase of Fuel Price by 10% | 10% | 270,713,870,363.11 | 2.801322403 |
| Drop of fuel price by 10% | 10% | 323,757,689,053.97 | 3.539743475 |

Based on the table above, there is a small difference between the calculation results of design option 1 and design option 2. For construction delay, reduction of power generation by 10% and drop of fuel price by 10%, there is an approximately 4% of internal rate of return while in the increase of fuel price by 10 %, the EIRR is approximately 3%.

**Graphical Representation**

**CASE 1.** Reduce of Power Generation by 10%

The first case for the analysis is the reduction of power generation by 10% in the span of 25 years. The graph below shows the breakeven point of design option 2 for case 1.

**Figure 28.** Break-Even Graph (Design Option 2/ Case 1)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 2 in the reduction of 10% in the power generation. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.

**CASE 2.** Increase of fuel price by 10%

The second case for the analysis is the increase of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 2 for case 2.

**Figure 29.** Break-Even Graph (Design Option 2/ Case 2)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 2 in the increase of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.

**CASE 3.** Drop of fuel price by 10%

The third case for the analysis is the drop of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 2 for case 3.

**Figure 30.** Break-Even Graph (Design Option 2/ Case 3)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 2 in the drop of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.

For design option 3, the table below shows the summary of calculation of sensitivity analysis which includes several cases.

**Table 33.0**

**Sensitivity Analysis for Design Option 3**

|  |  |  |  |
| --- | --- | --- | --- |
| Particular | Change | ENPV | EIRR |
| Base case |  | PHP | % |
| Construction delay | 1 year | 470,216,909,831.42 | 5.045078492 |
| Reduce of Power Generation by 10% | 10% | 457,661,207,483.83 | 4.931418604 |
| Increase of Fuel Price by 10% | 10% | 407,492,347,910.47 | 4.445217472 |
| Drop of fuel price by 10% | 10% | 488,971,552,985.35 | 5.209540527 |

Table 21.0 shows the possible outcome in some cases such as construction delay, reduce of power generation by 10%, increase of fuel price by 10% and drop of fuel price by 10%. Based on the table, if there will be a delay in construction, there will be approximately 5% of internal rate of return. For the reduction of power generation, the EIRR is approximately 4.93%. While increasing and decreasing of fuel price by 10% will have an EIRR of 4.45% and 5.21%, respectively.

**Graphical Representation**

**CASE 1.** Reduce of Power Generation by 10%

The first case for the analysis is the reduction of power generation by 10% in the span of 25 years. The graph below shows the breakeven point of design option 3 for case 1.

**Figure 31.** Break-Even Graph (Design Option 3/ Case 1)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 3 in the reduction of 10% in the power generation. The intersection of the two factors is the break-even point which is on the 4.5 year of operation.

**CASE 2.** Increase of fuel price by 10%

The second case for the analysis is the increase of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 3 for case 2.

**Figure 32.** Break-Even Graph (Design Option 3/ Case 2)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 3 in the increase of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.

**CASE 3.** Drop of fuel price by 10%

The third case for the analysis is the drop of fuel price by 10% in the span of 25 years. The graph below shows the breakeven point of design option 3 for case 3.

**Figure 33.** Break-Even Graph (Design Option 3/ Case 3)

The graph above shows the behavior of the cash inflow and the cash outflow for design option 3 in the drop of the fuel price by 10%. The intersection of the two factors is the break-even point which is on the 3.5 year of operation.