Process Simulation and Cost Optimization of a Gas based Power Plant including amine-based CO_2 Capture

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Abstract

CO_2 capture from gas turbine exhaust gas using heat from the power generation cycle is a possibility for CO_2 emission reduction from natural gas-based power plants. A simplified power plant was simulated in Aspen HYSYS with a compressor, a combustion chamber, a turbine, a steam circuit with a steam heater, a high-pressure steam turbine, a low-pressure steam turbine, a steam condenser, and a circulating pump. CO_2 capture was simulated with an absorption column, a rich amine pump, a lean/rich amine heat exchanger, a desorber with a reboiler and condenser, a lean pump and an amine cooler. The equipment cost was obtained from Aspen In-plant Cost Estimator, and an enhanced detailed factor method was used to estimate the total investment. A base case with combustion at 30 bar, ΔT_{MIN} of 10 °C, and 10 stages (meters of absorber packing) was simulated, dimensioned, and cost estimated. In earlier works, optimum parameters have been found by minimizing the cost of CO_2 capture. In this work, optimum was defined as the maximum profit for a combined process with 85 % capture efficiency. Optimized parameters were calculated to 25 bar for the combustion pressure, 13 °C for the minimum temperature approach in the lean/rich amine heat exchanger, and 10-meter packing height in the absorption column. These values are comparable to values in literature.

Keywords: *Carbon capture, Aspen HYSYS, gas turbine, cost estimation, simulation.*

1. Introduction

CO_2 capture from fossil fuel-based power plants is extensively studied in the literature (Liang et. al, 2015; Li et al., 2016). Some papers include power production and CO_2 capture in their studies (de Ruick, 1992; Kvamsdal et al.., 2007; Øi, 2007; Mathisen et al., 2011; Schach et al., 2010; Amrollahi, 2012; Karimi et al., 2012; Hu et al., 2017; Luo et al., 2015). There is also much literature on the cost estimation of CO_2 capture (Rao and Rubin, 2002; Ali, 2019; Shirdel et al., 2022).

Research work on the combination of simulation, cost estimation and cost optimization of CO_2 capture has been performed by Kallevik (2010), Øi (2012) and Shirdel et al. (2022). In a Ph.D. Thesis by Ali (2019), the Enhanced Detailed Factor (EDF) method was presented. Øi et al. (2021) evaluated the automated calculation of cost optimum process parameters in the CO_2 capture process. Typical parameters to optimize in an amine-based process are the number of stages in the absorption column and the minimum temperature approach in the heat exchangers.

Nord et al. (2017), Kazemi et al. (2022) and Øi et al. (2022) have evaluated simulation and cost evaluation of combined power generation and CO_2 capture. Nord et al. (2017) and Øi et al (2022) evaluated this for an offshore application.

For a natural gas-based power plant, typically a Natural gas combined cycle (NGCC) plant, the tools GTPRO, GTMASTER and GateCycle have been used for simulation. For CO_2 capture, the programs Aspen Plus, Aspen HYSYS and Unisim are standard programs. One paper (He and Ricardez-Sandoval, 2016) has used Aspen Plus for both an NGCC and a CO_2 capture process, and one paper (Hu et al., 2017) has used Unisim for both parts.

This study presents findings derived from the master's thesis by Aboukazempour (2023). The focal point of this research lies in the simulation and cost optimization of a natural gas-based power plant with integrated CO_2 capture using Aspen HYSYS simulation software. A novel aspect of this investigation involves the integration of a power plant and a carbon capture facility which enable the cost optimization of several key parameters, including the power plant's inlet pressure, the number of stages in the absorption column and the minimum temperature difference in the heat exchangers. These optimum parameter values were found by optimization of the net present value assessment of the entire system.

2. Process Description and Specifications

2.1. Process Description

Fig. 1 shows a simplified NGCC process. Natural gas is combined with compressed air in the combustion chamber and produces power in the expander part of the gas turbine. The turbine exhaust heats steam in the steam generator which produces power in a steam turbine before it is pumped back to the steam generator.

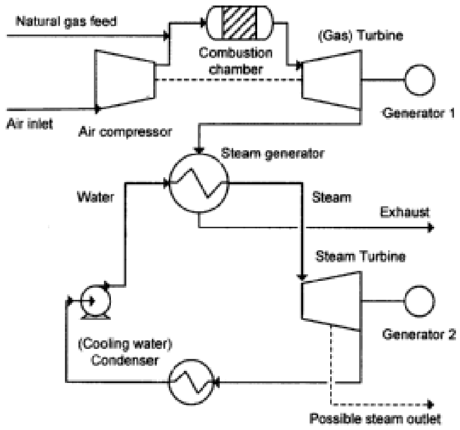

Figure 1: Combined cycle power plant (Øi, 2007)

Fig. 2 shows the CO_2 capture process. The flue gas is cooled in the Direct Contact Cooler (DCC) before the CO_2 is absorbed in lean amine in the absorber. The rich amine from the bottom is pumped through a heat exchanger to the desorber where CO_2 is the top product and regenerated lean amine from the bottom is returned through the heat exchanger and a cooler to the absorption column.

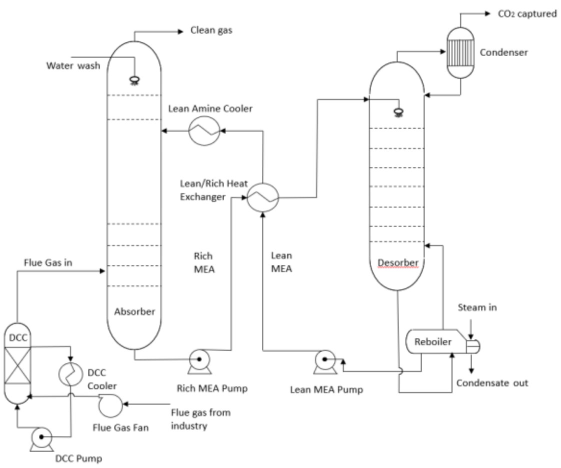

Figure 2: Process flow diagram of a standard amine-based CO2 capture process (Aromada et al., 2020)

2.2. Process Specifications and Simulation

The process specifications used for the base case simulation are presented in Tables 1 and 2. The process simulation in this work is similar to the work of Øi (2007). The simulations were performed in Aspen HYSYS Version 12. The base case was simulated to capture 85 % CO_2 from exhaust gas from the simplified NGCC power plant. The process has a 10 ℃ temperature difference in the main heat exchanger.

The Aspen HYSYS process flow diagram showing all the equipment included in the scope of the study is shown in Fig. 3.

Table 1: Aspen HYSYS specifications for base case power plant model

Parameter	Value
Inlet air temperatures	25 ºC
Inlet natural gas pressure	30 bar
Combustion temperature	1500 ºC
Steam high pressure	120 bar
Steam medium pressure	3.5 bar
Steam low pressure	0.07 bar
Pressure to stack	1.01 bar
Stack temperature	100 ºC

Table 2: Specifications for the CO_2 capture process

Items	Specifications [Unit]	Value
Inlet Flue Gas	Temperature [°C]	40
	Pressure [bar]	1.1
	Molar flow rate [kmol/h]	71345
	CO_2 content [mole %]	4.61
	H_2O content [mole %]	6.71
Lean MEA	Temperature [°C]	40
	Pressure [bar]	1.1
	Molar flow rate [kmol/h]	99496
	MEA content [W %]	28.92
	CO_2 content [W %]	5.39
Absorber	Number of stages	10
	Murphree efficiency	0.25
	Rich amine pump pressure [bar]	2
	Rich amine temp. out of Lean/Rich amine HEx [°C]	102.7
Desorber	Number of stages in stripper	6
	Murphree efficiency	1.00
	Reflux ratio in the desorber	0.3
	Reboiler temperature [°C]	120
	Pressure [bar]	2
	Lean amine pump pressure [bar]	5

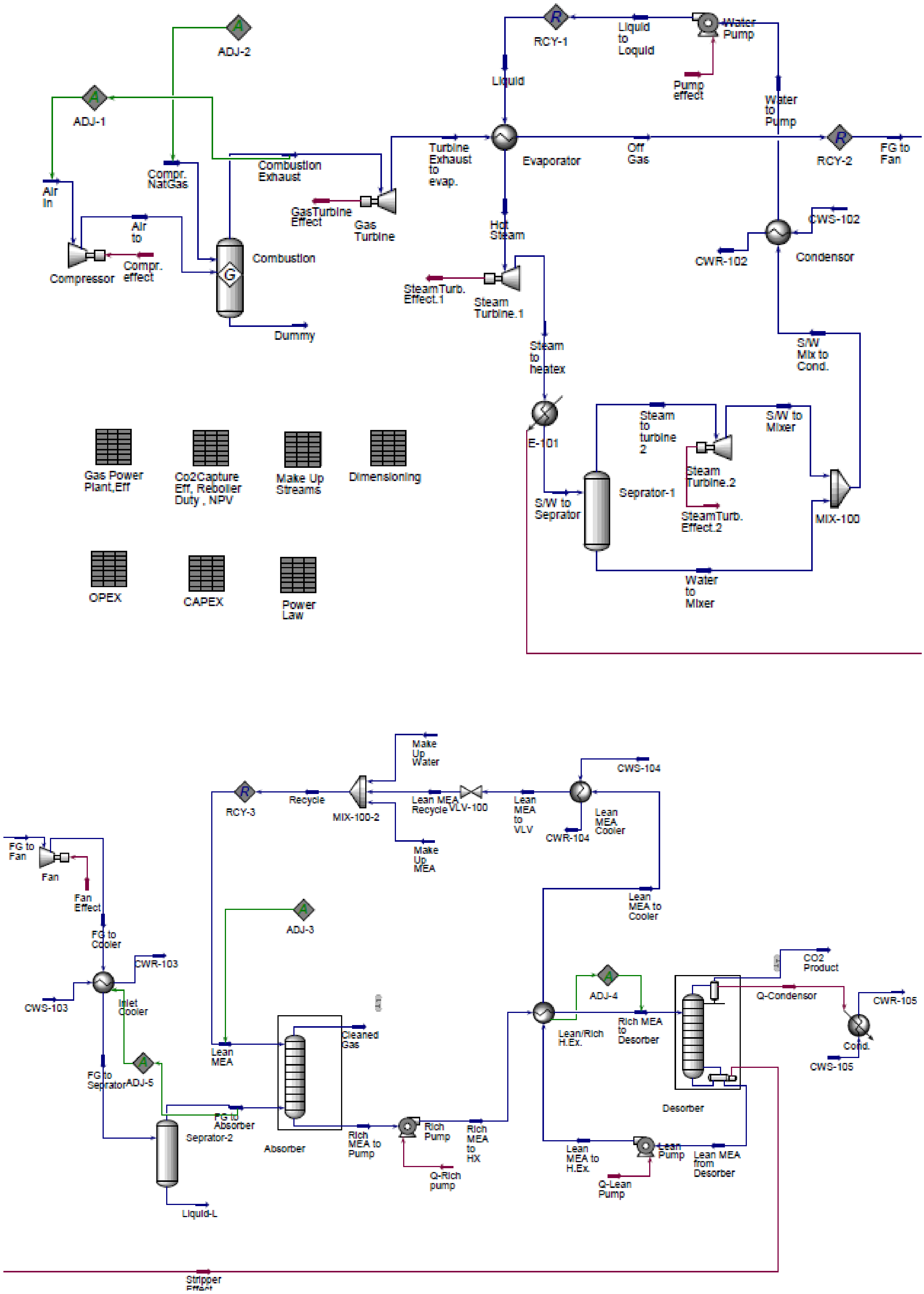

Figure 3: Combined power plant and CO_2 capture process flowsheet in Aspen HYSYS (Aboukazempour, 2023)

2.3. Equipment Sizing

Murphree efficiencies of 0.25 and 1.00 were specified for all the absorber and desorber stages, respectively. For the absorber and desorber internals, structured packing was assumed, and one stage was assumed to correspond to 1 meter of packing height. The column diameters were calculated based on a gas velocity of 2.5 m/s and 1 m/s, respectively, as in Park and Øi (2017) and Øi et al. (2021). The total height of the absorption column and desorption column were specified to be packing height plus 25 m and 15 m respectively (Kallevik, 2021) due to distributors, water wash packing, demister, gas inlet, gas outlet, and sump. 75 % adiabatic efficiency was specified in the pumps, compressors and expanders. Overall heat transfer coefficient values have been specified for the lean/rich heat exchanger to 732 W/(m^{2}K). These values are close to the same as in Øi (2012) and Park and Øi (2017) and slightly less than the numbers in Øi et al. (2021) which are regarded as optimistic.

2.4. Capital and Operating Cost Estimation

The equipment costs were calculated in Aspen In-plant Cost Estimator version 12, which gives the cost in Euro (€) for the Year 2020. A generic location (e.g. Rotterdam) was assumed and stainless steel (SS316) with a material factor of 1.3 was assumed for all equipment units. In a detailed factor method like the EDF method, each equipment cost (in carbon steel) was multiplied by an installation factor to get the equipment installed cost. The installation factor is a function of the site, equipment type, materials, and size of the equipment and includes direct costs for erection, instruments, civil, piping, electrical, insulation, steel and concrete, engineering cost, administration cost, commissioning and contingency. The updated installation factors for 2020 (Aromada, 2021) were used. The specifications for operating cost estimation are found in Table 3.

Table 3: Cost calculation specifications.

Item	Value	Unit
Operating Lifetime	25	[year]
Construction Lifetime	3	[year]
Operation Lifetime	22	[year]
Discount rate	7.5 %	-
Operating Hours	8000	[h/year]
Electricity Price	0.136	[€/kWh]
Natural gas Price	1.29	[€/m3]
Cooling water Price	0.022	[€/m3]
Water process Price	0.203	[€/m3]
Solvent MEA Price	1450	[€/ton]
Maintenance Price	4% of CAPEX	[€/year]
Operator Price	80414 × (12 Operators)	[€/year]
Engineer Price	156650 × (2 Engineer)	[€/year]

2.5. Net Present Value (NPV) and Payback Period

Cost optimization can be based on the maximization of the net present value (NPV) of the project. This common measure is defined by Equation (1) for a defined process plant and a defined time of operation.

$$NPV = CAPEX + NPV_{OPEX} \quad (1)$$

Where:

- NPV= Net present value for the total costs [€]
- CAPEX = Installation expenses for equipment [€]
- NPV_{OPEX} = The total cost of OPEX for the calculation period [€]

In this work, the NPV_{OPEX} cost for the calculation period is calculated and added to the CAPEX cost to obtain the total NPV. The NPV_{OPEX} cost is obtained by Equation 2:

$$NPV_{\ OPEX} = \sum_{N=3}^{End} \{(a) \times \frac{1}{(1+i)^N}\} \quad (2)$$

Where:

- i = annual interest rate
- a = annual operation cost [€]
- N = number of years

The calculated NPV in Equation (1) consider all the incomes and costs related to the utilities and the CAPEX. The NPV of the early years is negative, but it will be positive after this period due to the income related to the sale of electricity. A higher NPV indicates that the project is more profitable. The cost calculation shows a €1570 million net present value over a 25-year plant lifetime.
As seen in Fig. 4, after six years of operation after construction (the ninth year in the table), the NPV of the project becomes positive, which indicates a six-year payback period.

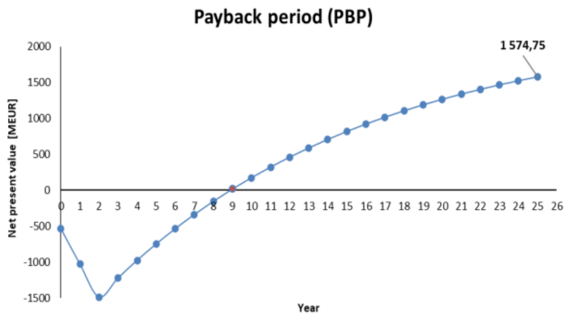

Figure 4: Payback time for the base case (Aboukazempour, 2023)

3. Results and Discussion

3.1. Simulation Results of the Base Case Model

The 400 MW net electricity output and 85% CO_2 removal are the main adjusted parameters in this Aspen HYSYS simulation. Based on these goals these three main parameters inlet pressure into the power plant, the number of stages in the absorption column, and the minimum temperature approach in the lean/rich heat exchanger were optimized based on the net present value during the total lifetime project.

3.2 Optimization of Combustion Pressure

Fig. 5 shows NPV as a function of inlet pressure and combustion pressure with an optimum of 25 bar. Earlier suggestions for optimum pressure vary between 15 and 35 bar. 18 bar has been suggested as an optimum by Horlok (2003), but he claims that 30 bar is optimum for a gas turbine operating alone. Soares (2015) states that a higher combustion temperature favors a higher pressure with 12 bar at 1100 K and higher than 40 bar at 1800 K. Ibrahim et al (2011) state that the highest total efficiency of combined cycle gas turbines takes place at a high compression pressure ratio with low ambient temperature as in this work. The gas turbine in this work operates at about 1800 K. In the modern heavy-duty Siemens gas turbine, the pressure is 24 bar which is close to the optimum for this work. The optimization in this work is a simplification but shows that a combined model gives reasonable results compared to earlier optimization by e.g. Horlok (2003) and Ibrahim et al. (2011).

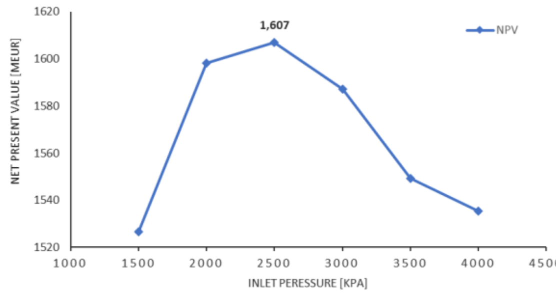

Figure 5: NPV calculation as a function of inlet pressure for base case (Aboukazempour, 2023)

3.3 Optimization of Minimum Temperature Approach in lean/rich amine heat exchanger

Fig. 6 shows NPV as a function of the minimum temperature approach in the main lean/rich amine heat exchanger. The figure shows a flat optimum between 13 and 17 °C with an optimum at 13 °C. There are several sources indicating an optimum between 10 and 15 °C (Øi, 2012; Øi et al., 2021; Aromada et al., 2022; Shirdel et al., 2022; Øi et al., 2022). It is well-known that the optimum is quite flat.

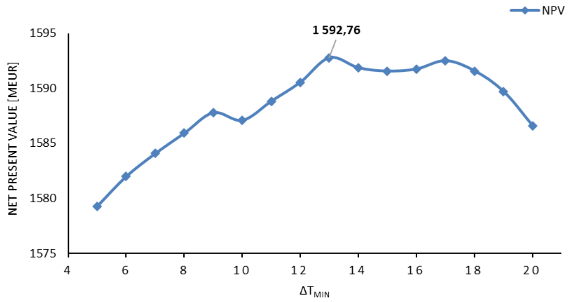

Figure 6: Manual NPV calculation results as a function of the minimum temperature approach (Aboukazempour, 2023)

Fig. 7 shows NPV as a function of the minimum temperature approach for both manual and automated calculations. The manual calculations give a smoother curve. The reason is that the manual calculations (or manual adjustment of the convergence) can adjust the convergence more accurately. The automated calculations are based on a case study, where some of the recycles are not adjusted. The optimum temperature approach is 13 °C for the manual calculation and 14 °C for the automated calculation.

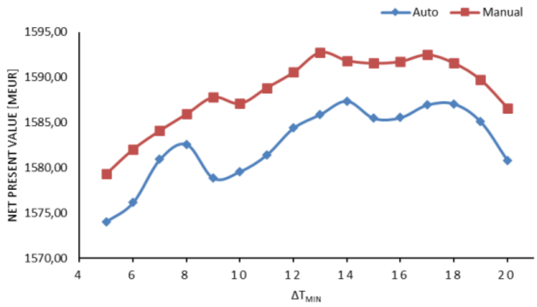

Figure 7: Comparison of manual and automatic NPV results for the minimum temperature approach. (Set Point: ΔTmin = 10 °C), (Aboukazempour, 2023)

3.4 Optimization of the number of absorption stages

Fig. 8 depicts the relationship between NPV and the number of stages in the absorber column, showing an optimal configuration at 10 stages (measured in meters of packing). In contrast, alternative references have computed optimal column heights within the higher range of 12 to 18 meters, as in works like Amrollahi (2011), Øi (2012), Aromada et al. (2022), Shirdel et al. (2022), Øi et al. (2021) and Øi et al. (2022).

The greater number of stages observed in preceding absorber studies could be attributed to the pursuit of more ambitious CO_2 removal efficiency targets. Within the scope of this research, achieving an 85% CO_2 removal rate would likely correspond to a lower optimal absorption column height.

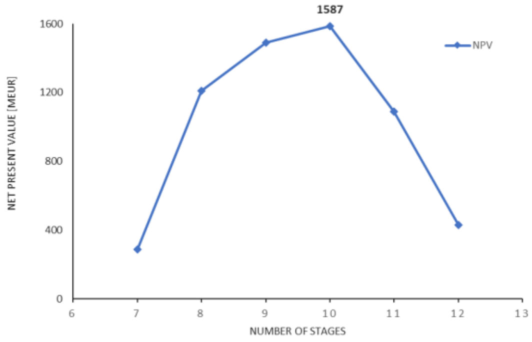

Figure 8: Manual NPV calculation results for the number of stages in the absorber column (Aboukazempour, 2023)

3.5 *Modified Base Case Model*

The initial scenario was modified using the best parameters identified in the sensitivity analysis. Table 4 displays the optimal process parameters employed in this adjusted scenario simulation.

Table 4: Aspen HYSYS optimum parameters results based on the net present value (NPV), (Aboukazempour, 2023)

Modified parameter	Value
Inlet pressure into the power plant	2500 kPa
Minimum approach temperature (ΔT_{min})	13 °C
Number of stages in the absorption column	10

The modified scenario projected a net present value of 1900 million Euro compared to 1600 million Euro for the initial scenario. The payback duration was reduced from 6 years to 5 years. Fig. 9 illustrates the payback period of the modified scenario based on the net present value of the project.

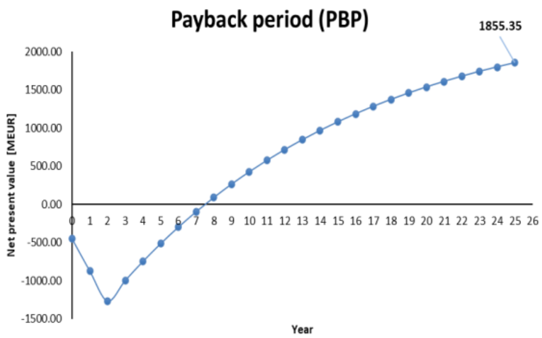

Figure 9: Payback period of the modified base case. (Aboukazempour, 2023)

3.6 *Simultaneous parameter optimization*

While the current focus in this paper is on refining individual parameters, it is essential to recognize the potential benefits of optimizing all relevant factors simultaneously. This was performed by Karzemi et al. (2022), but this was only energy optimization and not economic optimization. Although it is concentrated on optimizing combustion pressure, absorption column stages and heat exchanger temperature in this study, it is worth noting that these parameters are interconnected. A comprehensive optimization approach may lead to more accurate and refined optimum results.

Although simultaneous optimization of several parameters is not calculated in this study, Aspen HYSYS provides a platform for such investigations.

Apart from Aspen HYSYS, other software tools like Aspen Plus, Unisim, and GateCycle also offer capabilities for simultaneous optimization of several parameters.

3.7 *Accuracy, uncertainties and limitations*

Uncertainties from process assumptions, cost estimation and parameter adjustments significantly impact the study's precision. Notably, there are substantial uncertainties in estimating process equipment costs, especially regarding main equipment installation expenses. This concern is particularly pronounced for high-cost components such as compressors and gas turbines. The cost of natural gas also has a considerable influence on the net present value of a power plant with or without CO_2 capture.

4. Conclusion

A standard gas-based power plant process including CO_2 capture based on absorption into monoethanolamine (MEA) has been simulated and cost estimated with an equilibrium-based model in Aspen HYSYS2.0. The power plant exhaust is the input to the CO_2 capture simulation, and the steam demand for CO_2 capture is the input to the power plant simulation.

The power plant was calculated with a compressor, a combustion chamber, a turbine, a steam circuit with a steam heater, a high-pressure steam turbine, a low-pressure steam turbine, a steam condenser, and a circulating pump. The CO_2 capture plant was simulated with an absorption column, a rich amine pump, a lean/rich amine heat exchanger, a desorber with a reboiler and condenser, a lean pump, and an amine cooler. The equipment cost was obtained from Aspen In-plant Cost Estimator V12.0, and an enhanced detailed factor (EDF) method was used to estimate the total investment. A base case with combustion at 30 bar, ΔT_{MIN} of 10 °C and 10 stages (meters of packing in the absorber) was simulated, dimensioned and cost estimated.

In earlier works, cost optimum parameters have been found by minimizing the cost of CO_2 capture. In this work, optimum was defined as the maximum profit for a combined process with 85 % capture efficiency.

Optimized parameters were the minimum temperature approach in the lean/rich amine heat exchanger, the number of absorption column stages and the combustion pressure in the power plant. The optimum values were calculated to 13 °C, 10 stages, and 25 bar. These values are comparable to values in the literature.

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