applied sciences

*Article*

# Natural Gas Flaring Management System: A Novel Tool for Sustainable Gas Flaring Reduction in Nigeria

**Robin Abu, Kumar Patchigolla *, Nigel Simms and Edward John Anthony**

School of Water, Energy and Environment, Cranfield University, Cranfield MK43 0AL, UK
* Correspondence: k.patchigolla@cranfield.ac.uk; Tel.: +44-1234754124

**Abstract:** The use of hydrocarbon fuels increases with population growth and rising standards of living, and so does natural gas flaring. Natural gas flaring is both a waste of natural resources and a violation of Nigeria's energy policy for sustainable development through natural gas conservation. However, it remains the most cost-efficient and effective associated natural gas (ANG) management option in developing countries such as Nigeria. The World Bank's initiative to eliminate routine gas flaring by 2030 has increased the need to limit or eliminate routine gas flaring. Often, studies on natural gas utilisation techniques fail to consider the lack of practical tools that integrate economic, technical, and regulatory factors into a gas flaring management framework, and the intricacies of existing tools, which often come at the expense of simplicity to achieve real-time information output. This paper aims to establish a framework and ANG management tool to reduce regular gas flaring in Nigeria. This research established a management framework (using a flowchart decision tree) and models to provide a user-friendly ANG flaring tool (using a MATLAB graphical front end user interface with back-end ASPEN HYSYS thermodynamic models). This was combined with techno-economic models for liquefied natural gas, gas-to-methanol, and gas-to-wire ANG utilisation options. The tool was then tested with data obtained from Fields Y and X in the Niger Delta region of Nigeria. The results, considering both economic and technical factors, showed that the choice of liquefied natural gas for Field Y was best due to its proximity to the pipeline infrastructure and its cost-effectiveness, and the availability of a high-demand LNG market for that area. For Field X, gas-to-wire was best due to its proximity to the electrical grid and high electricity requirements for that area. Additional geographical profiles in West Africa and ANG utilisation alternatives were recommended for further investigation. This paper developed and validated a one-of-a-kind ANG flaring management tool that incorporates techno-economic analysis of selected ANG utilisation options to assist operators and investors in making more profitable investment decisions.

**Keywords:** associated natural gas (ANG); gas flaring; gas flaring reduction; ANG utilisation options; ANG flaring management

check for updates

**Citation:** Abu, R.; Patchigolla, K.; Simms, N.; Anthony, E.J. Natural Gas Flaring Management System: A Novel Tool for Sustainable Gas Flaring Reduction in Nigeria. *Appl. Sci.* **2023**, *13*, 1866. https://doi.org/10.3390/app13031866

Academic Editor: Maris Klavins

Received: 18 December 2022
Revised: 15 January 2023
Accepted: 19 January 2023
Published: 31 January 2023



## 1. Introduction

The increasing energy demand has impacted the production, processing, and use of fossil fuels, and in particular, oil and gas resources. Both offshore and onshore fossil fuel sources facilitate the flaring and venting of natural gas with resulting negative environmental, social, and economic repercussions on the sustainability of natural resources. Despite its negative environmental impacts, gas flaring as a method for eliminating undesirable natural gases from crude oil is attractive due to its low cost. Flaring (the burning of associated gas during oil production and refining [1]) or venting (the regulated release of gases into the atmosphere during oil and gas operations) are common practices in oil and gas production to maintain safety [2]. Since venting contributes considerably to greenhouse gas emissions and reinjection is limited to the field conditions, flaring is favoured as a less hazardous practice that ensures reliable operation and is often considered an unavoidable process [3]. Gas flaring emits mainly carbon dioxide with typically 98% of the gas being burned, while venting emits methane [4,5]. Methane is the main emission from venting, and its global warming potential is 21 times that of carbon dioxide and thus is always likely to be worse than flaring, and there are increasing discussions about policy reforms to reduce these emissions [6–8].

Unfortunately, with the rising need for fossil fuels, the benefits of natural gas (associated and non-associated) serve as a major attraction for its use [9,10]. Natural gas has gained popularity as low-$CO_2$ fuels have expanded in use [11]. The IEA [12] claimed that natural gas alone contributed 45% of global energy demand growth in 2018. When compared to oil, natural gas emits 20% less $CO_2$. Gas combustion accounted for 21% of energy sector emissions, but oil accounted for 35% of $CO_2$ emissions. The combustion of natural gas generates less than 1% of sulphur dioxide compared to oil and less than half of the nitrogen oxide (a major component of smog) compared to oil, with natural gas accounting for less than 10% of global nitrogen oxide emissions. In addition, particulate emissions are low compared to oil. The increasing growth of the global gas industry suggests that natural gas should contribute significantly to the energy mix [13].

Natural gas, which was formerly viewed as a by-product of oil production, now provides one-fifth of the world's essential energy [10]. Despite efforts to curb gas flaring, it remains an issue, especially in developing countries such as Nigeria (the country of interest for this paper) with substantial oil and gas production. Nigeria ranked seventh among the top thirty flaring countries in 2021, with a volume of 6.6 billion cubic metres (bcm), contributing more than 40% of Africa's overall annual flare volume. Nigeria is Africa's largest emitter of greenhouse gases, with 123 flaring sites in the Niger Delta. According to PricewaterhouseCoopers (PwC) [14], Nigeria's economy lost N233 billion (USD 761.6 million) to gas flaring in 2018, accounting for 3.8% of total worldwide losses. This is because the oil and gas sector accounts for around 10% of the country's gross domestic product (GDP) and petroleum export revenues account for more than 86% of Nigeria's overall export revenue [15]. According to the National Environmental Economic Development Study (NEEDS) for climate change in Nigeria, gas flaring costs N28.8 billion (USD 94 million) annually [14]. Nigeria's flared gas fraction fell from 51% in 2001 to 10% in 2018, with 7.4 billion cubic feet (bcf) (~0.21 bcm) flared, placing Nigeria in the top ten gas flaring countries [16]. Approximately 2.5 bcf is flared at various places across the country [17]. This accounts for around a quarter of Africa's electricity usage [17]. Flaring levels in Nigeria are evidently unacceptably high, considering the environmental issues, health risks, and economic losses.

In Nigeria, a lack of practical approaches in the public domain that include economic, technical, and regulatory considerations into an associated natural gas (ANG) management framework for minimising gas flaring has hampered gas flaring reduction. Some Nigerian oil and gas firms have developed their own ANG flare reduction systems, but attempts to reduce Nigerian gas flaring are impeded by a lack of information on their existence and public access to them if they do exist [16].

Relatively fast, real-time information from a convenient, user-friendly management tool that is easily modified and updated for optimisation and performance, and which also employs techno-economic analysis to compare the economic feasibility and viability of various ANG utilisation options for the choice of the optimal utilisation option, has beneficial consequences for oil and gas investors and companies. The data acquired here can be used in predictive analysis and simulation efforts for other fields to obtain real-time information output. The cost–benefit analysis, especially at the theoretical stage, increases the process feasibility and efficiency.

Investment decisions can be made more rapid and definitive through the application of such a tool, with its development offering a vital pathway to reduce gas flaring through correct selection and application of conservation and utilisation options, by reflecting on the regulatory, economic, technical, and techno-economic factors that affect such decisions. While several tools have utilised these factors, the intricacy of such tools have often come with the loss of simplicity and speed of operation. A paucity of research on Nigeria-specific case studies that highlight the viability of an ANG utilisation tool and framework for the Nigerian situation persists; thus, practical solutions to reduce gas flaring in Nigeria offer a major opportunity. This paper develops a systematic framework and management tool to enable the reduction in routine gas flaring in Nigeria, promote its economic benefit, and minimise the emission of $CO_{ed}$. Sustainable development through an efficient ANG management system could inspire and aid investors or operators in making more financially rewarding investment decisions, which in turn would accelerate progress toward the goal of achieving zero routine flaring by 2030.

## 2. Materials and Methods

This section examines various materials and step-by-step methods used to achieve the goal of this paper. This includes a description of the case study fields, various process models, and descriptions of the liquefied natural gas (LNG), gas-to-wire (GTW), and gas-to-methanol (GTM) processes chosen for utilising natural gas in accordance with the authors' [18] recommendation in their paper "A Review and Qualitative Assessment of Natural Gas Utilisation Options for Eliminating Routine Nigerian Gas Flaring," as well as the development, description, and application of the routine ANG management tool and its integration with the techno-economic models (combination of the process and economic models).

### *2.1. Case Study Field*

Here we analyses two oil fields. The field selection is based on the volume of gas flared, the frequency of field gas flaring activities, the field's location, and the absence of a sustainable system for using all associated natural gas. Each field has been coded Y and X to protect operator confidentiality (see Figure 1). The Department of Petroleum Resources (DPR) in Nigeria gathered monthly ANG data for this field in the Niger Delta region for the period between 2014 and 2018 (see Figures 2 and 3). Additionally, the annual average of these monthly data was computed and used to generate Figures 2 and 3 (see Table A1). The ANG that remains for Field Y after subtracting the amount of ANG produced and flared is used for onsite power generation, steam generation, heating, cooling, and re-injection.

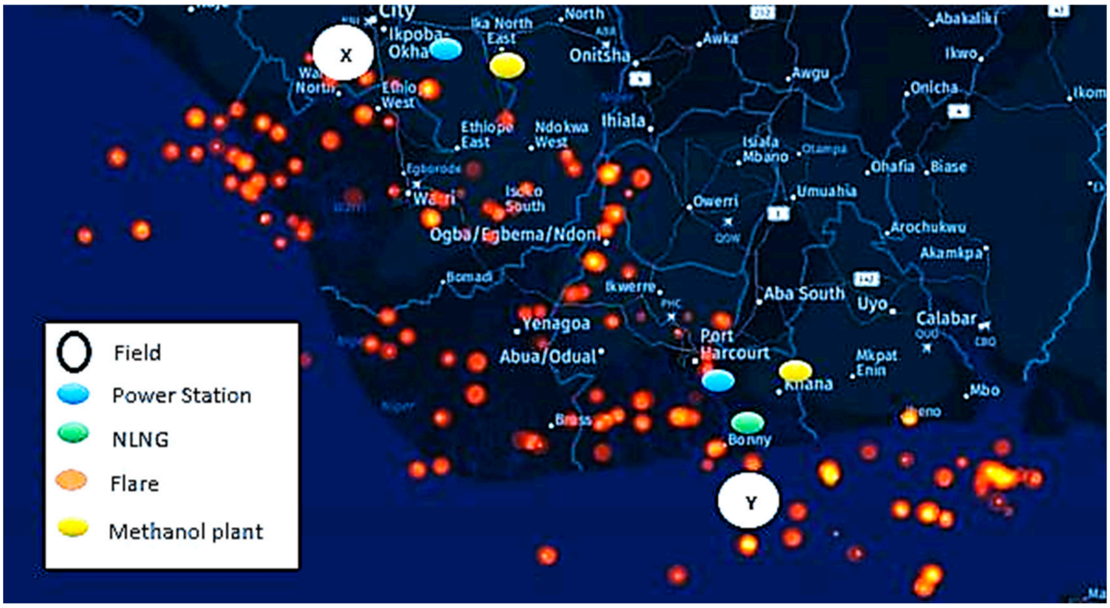


**Figure 1.** Location of gas flaring fields for this study in the Niger Delta region of Nigeria (adapted from [19].

### 2.1.1. Case Study: Field Y

Overview—Field Y is located in an oil mining lease (OML) in water depths ranging from 750 m to 850 m in the South-South Niger Delta region, approximately 64 km offshore from the Rivers State, Nigeria (see Figure 1). This field has reserves of over 193 million barrels of oil and 1 trillion cubic feet of gas. Average annual oil, gas, and flared gas output are 11 million barrels, 66,293 mmscf, and 26,493 mmscf, respectively. In Field Y, the average quantity of ANG flared every year is more than 39 percent of the average gas produced. Figure 2 shows trends for the average monthly natural gas produced and flared. Here, the average volume of ANG flared fluctuates in a similar pattern from January to August, but shows a steep rise in flare volume of more than 50 percent of the gas produced from August to September before dropping, which may be due to the development of new output wells, aged wells generating more gas than oil, pipeline vandalism, a shortage of re-injection operations, and a lack of sustainable usage plans for ANG. The peak and base volumes of the ANG flared are reported in September and October.

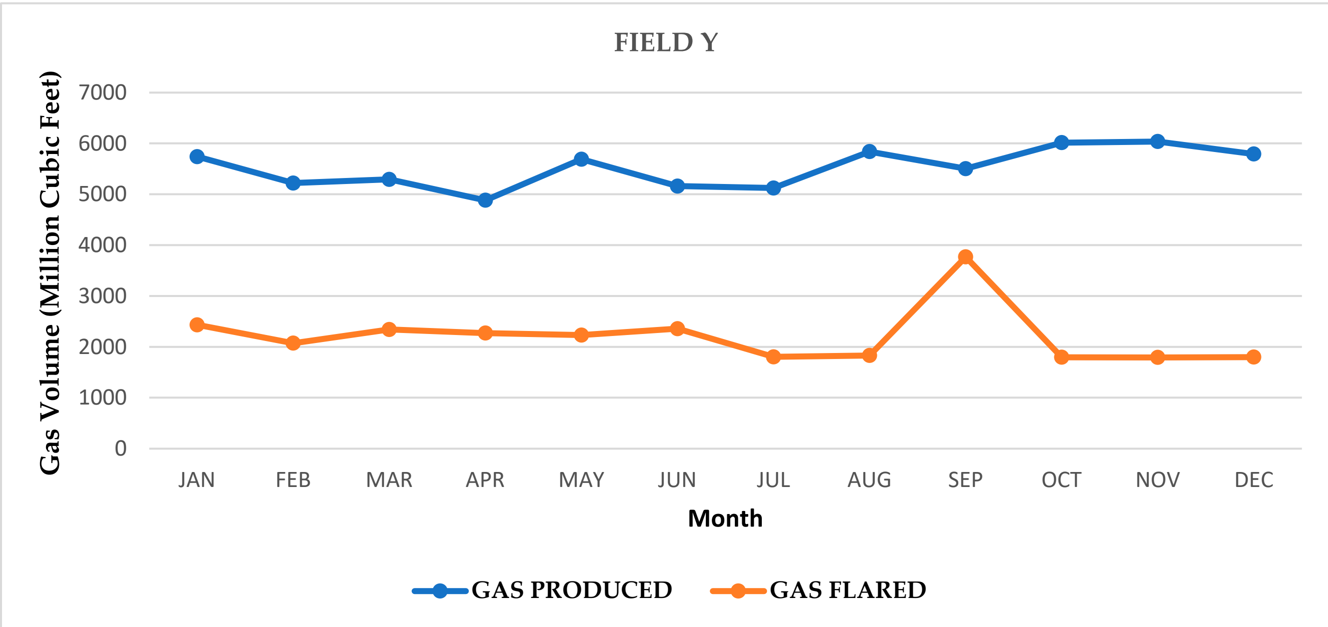


**Figure 2.** Average gas produced and flared in Field Y per month. Source: Authors' construction based on data collected from DPR in Nigeria.

### 2.1.2. Case Study: Field X

Overview—Field X is located in an oil mining lease (OML) on land (onshore) of Delta State in the South-West Niger Delta region, Nigeria. It currently flares all gas produced as it lacks a gas utilisation system. This field has reserves estimated at over 120 million barrels of oil and 0.347 trillion cubic feet of gas. The total average oil produced per year, total average gas produced per year, and total average flared gas generated per year are 4 million barrels, 27,338.01 mmscf, and 17,246.67 mmscf, respectively. The average amount of ANG flared per year in Field X is more than 62% of the average gas produced per year, which is a high rate. Figure 3 shows the pattern of average gas generated and flared per month.

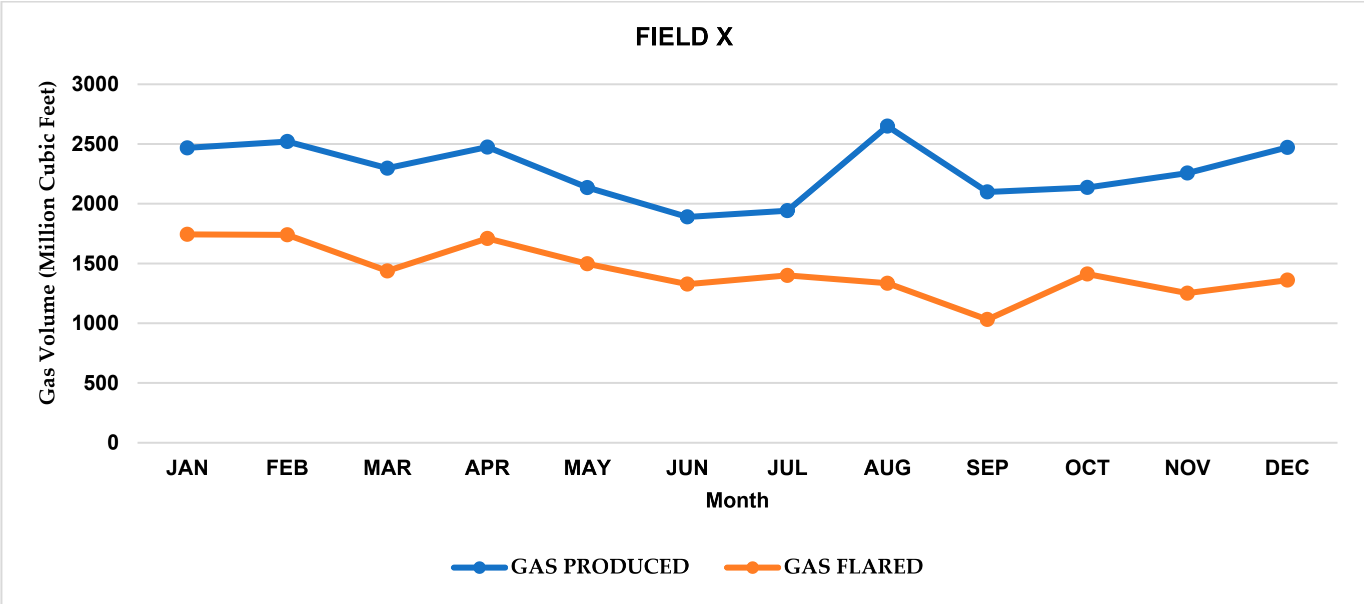


**Figure 3.** Average gas produced and flared in Field X per month. Source: Authors' construction based on data collected from DPR in Nigeria.

*2.2. Process Model Description*

In this work, Aspen HYSYS software was used to model and simulate the LNG, GTW, and GTM utilisation processes. The Peng–Robinson equation was used because it supports the broadest spectrum of operating conditions [20]. To achieve an outcome obeying thermodynamic laws (e.g., degrees of freedom), the simulation relies on the balance of mass, material, and energy. Specification of the flow rate, composition, operational parameters (temperature and pressure) of the inlet flows, and operational parameters in the process results in the computation of energy and material flow estimation of all process conditions and sizing of the unit operations.

2.2.1. LNG Process Model Description

In this section, an Air Products and Chemical Inc. (APCI) propane mixed refrigerant (C3MR) liquefaction process was modelled. The C3MR liquefaction process is favoured due to its suitability for small- to large-scale onshore and offshore natural gas liquefaction. In addition, this chosen liquefaction method is relatively easy, requires less energy, is a mature technology, and has positive economic advantages [21]. The complete facility for the LNG plant was not considered here, but rather the liquefaction only. Figure 4 displays the APCI's C3MR liquefaction process. The propane stream (upward stream) is divided into two streams by a splitter mechanism (TEE-100): one for natural gas pre-cooling (middle stream) and one for MR pre-cooling (downward stream). The triple heat exchangers (E-106, E-107, and E-108) use one of the separated propane streams (C3-NG) to pre-cool the supply gas to minus 35 °C. Each heat exchanger's exit stream is directed to a two-phase separator, whose liquid output is transferred to a mixer for process recycling and whose gaseous output is transmitted via a valve and utilised in a corresponding heat exchanger device. Valves control the pressure of input streams operating in a specified pressure range across the phase. Half of the divided propane stream is used before entering the main cryogenic heat exchanger (MCHE) to cool the MR to minus 35 °C. This stream follows the preceding stream, entering another triple heat exchanger successfully, but the vapour is separated from the liquid and used for heat exchange. The compressors (K-103, K-105, and K-105) are used between the MIX-100 and MIX-102 mixers to decompress the propane stream and the cooler (E-109) to reach input conditions (stream C3-1, 30 °C, 1100 kPa). Two wound coil heat exchangers (LNG-1, LNG-2) cool feed gas to meet final product specifications. Each LNG exchanger can use two heat transmission streams. LNG-1 has three inlet streams:

the vapour and liquid mixed refrigerant (MR) streams, and the natural gas pre-cooled stream. LNG-2 is supplied by gaseous MR and feed gas from LNG-1. The liquid MR flow travels through a valve to emerge as gas and then through a mixer (MIX-104) to combine with the LNG-2 exit vapour MR stream. The exit stream is heated by a heater (E-109) and rejoins LNG-1. The outlet stream is recycled through three coolers (E-100, E-101, and E-102) and three compressors (K-100, K-101, and K-102) for re-compression and cooling to inlet conditions (MR-1 stream, 30 °C, 4800 kPa). The vapour MR stream leaving the device is depressurised by a valve and returned to the heat exchanger, signifying the recycling of the streams at the second LNG exchanger. After the final gas flow through the valve, the LNG is brought to atmospheric pressure. LNG output is minus 162 °C. Table 1 provides the mixed refrigerant composition.

**Table 1.** Mixed refrigerant composition for LNG process [22,23].

| Component | Methane | Ethane | Propane | Nitrogen |
|---|---|---|---|---|
| Mole Fraction | 0.45 | 0.45 | 0.02 | 0.08 |

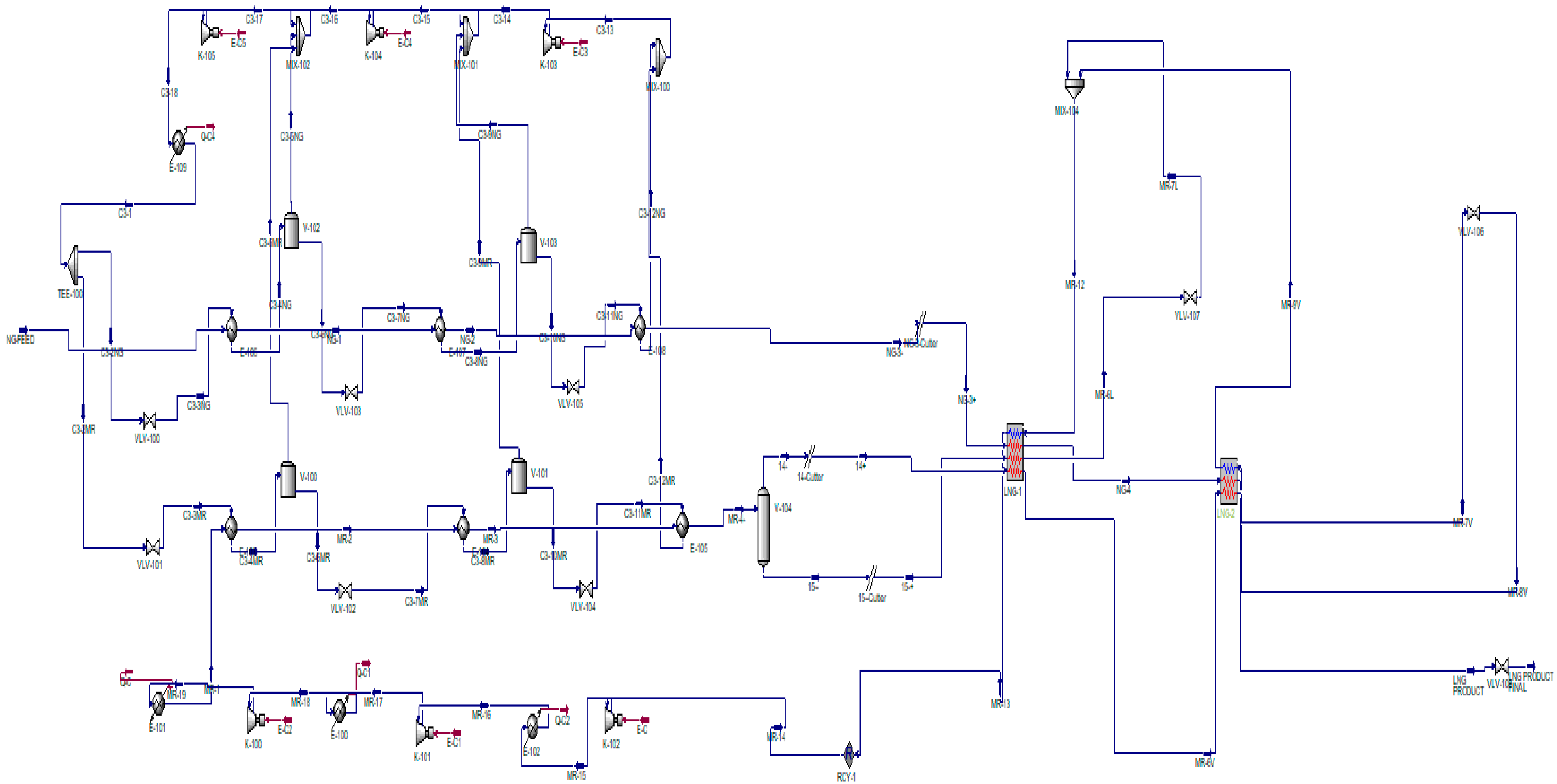

**Figure 4.** ASPEN HYSYS process flow diagram of the C3MR process.

#### 2.2.2. GTW Process Model Description

A natural gas combined cycle (NGCC) system has been considered for the development of GTW process. The GTW process flow diagram (PFD) in Figure 5 shows the NGCC system modelled in ASPEN HYSYS.

The NGCC power plant structure consists of two advanced combustion gas turbine generators with a dry low-NOx burner, two heat recovery steam generators (HRSG), and one steam turbine generator with high-pressure HP, intermediate pressure IP, and two flow low-pressure LP turbines. From the PFD, compressed air at 6 °C and 90 kPa is blended with natural gas fuel at 38 °C and 3100 kPa in the combustion chamber. The HRSGs (LNG-100 and LNG-101) capture waste heat from the gas turbine's exhaust stack. Three steam drums (P-100, P-101, and P-102) and superheater, reheater (RH), and economiser elements are intended for the HRSG. The HRSG system is fed feedwater (FW) to create HP steam. The HRSG generates main and reheat steam by exchanging heat between the supplied FW and the gas turbine exhaust and delivers it to the steam turbine HP (at 18,400 kPa and 565.6 °C), IP (at 3000 kPa and 564.4 °C) and LP sections while the cooled exhaust gas heads to the flare stack [24]. The steam turbine takes the HRSG's steam and sends its power to the generator's drive shaft. One half of the steam exhaust gas flows into an air-cooled condenser, where it is condensed and cooled by an air-cooling system, while the other part goes into a water-cooled condenser, where it is condensed and cooled by a cooling water system. Condensed and cooled exhaust gas becomes FW.

#### 2.2.3. GTM Process Model Description

This section describes the comprehensive development of the GTM process (mostly methanol synthesis), excluding gas treatment for the natural gas fuel (feed gas). Natural gas is utilised as the input gas to make synthesis gas, which is needed in the methanol production process. This study utilises a Lurgi low-pressure methanol technology with a two-step reforming synthesis gas production system (a combination of steam methane reforming and autothermal reforming). The process is ideally suited for the manufacture of methanol on small to large scales and is a mature technology. Figure 6 illustrates the ASPEN HYSYS methanol production process. Mass and energy balances have been constructed in every instance. The description of the simulation is divided into the following sections: feed conditioning, pre-reform, autothermal reformation (ATR), methanol synthesis, and methanol purification.

Feed conditioning—Natural gas at 50 °C and 7000 kPa is brought in and expanded to 3000 kPa pressure via a valve (VLV-100) until preheated to 497 °C. By heating fresh water, reformer steam with a temperature of 500 °C and a pressure of 3000 kPa is produced. Then, the natural gas and reformer steam are transferred to the pre-reforming section (steam methane reforming with water shift gas reaction).

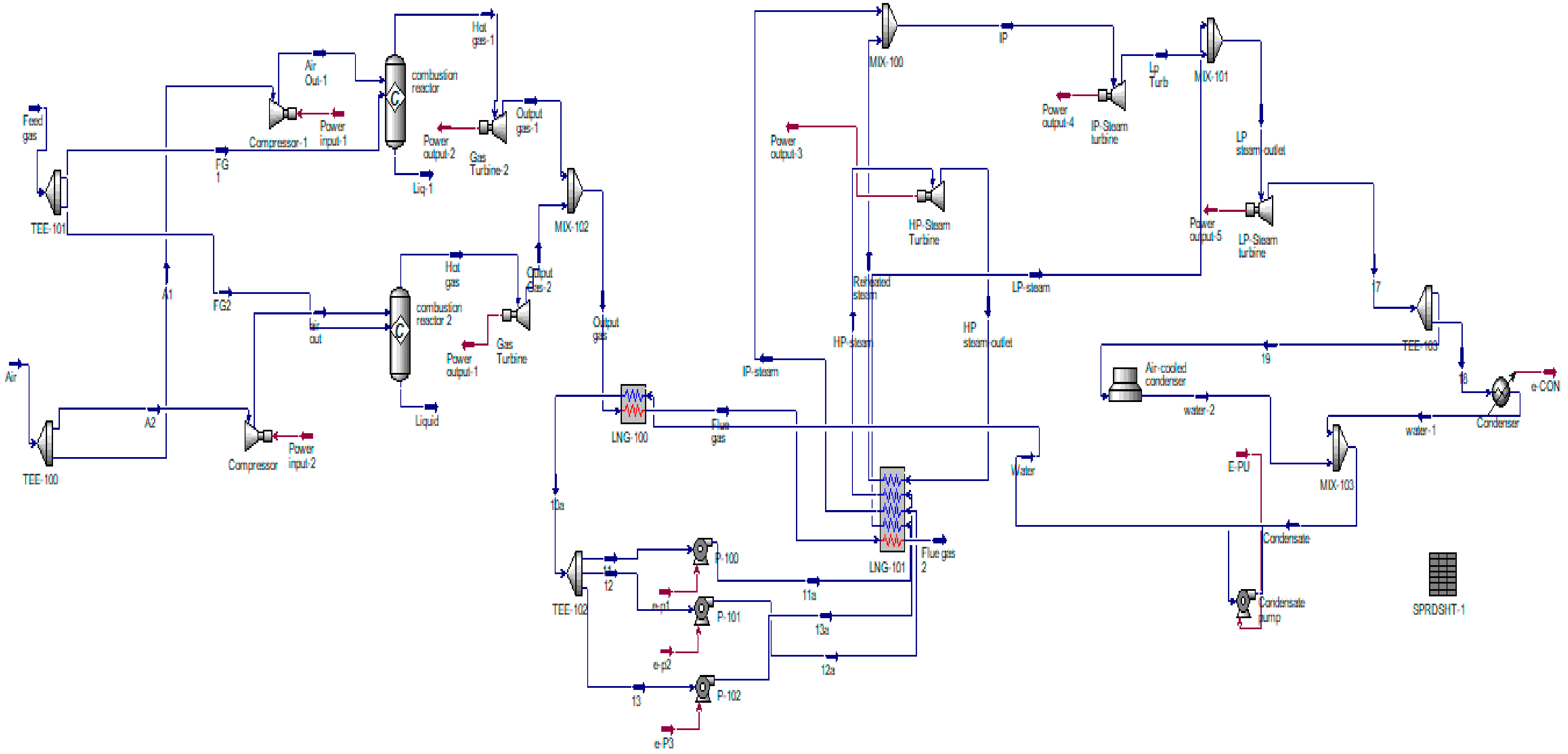

**Figure 5.** GTW ASPEN HYSYS process flow diagram.

Pre-reforming—Pre-reforming is a concept utilised in a standard adiabatic reactor for low-temperature steam-reforming of hydrocarbons. The heat content of the natural gas supply stream is used to execute the steam reforming process at low temperatures in the pre-reformer. It consists of two reactors. The first is a conversion reactor where higher hydrocarbons such as ethane, propane, and n-butane are converted into hydrogen and carbon monoxide. This reactor is adiabatic and completely converts all reactants. Preheated natural gas (feed gas) and steam are crucial components for reactions to continue. The unconverted natural gas (mostly methane) and its components are then sent to the next pre-reformer, the equilibrium reactor, which is modelled as an adiabatic reactor because of the three reactions of the reformer's combustor feed at 291 °C. The equilibrium reactor's processes consist of the methane steam reforming process and the water gas change or shift reaction. Both processes generate heat. The principal products (shift-1 feed) of the second pre-reformer are methane, water, hydrogen, carbon monoxide, and carbon dioxide. Due to a water gas change or shift reaction, carbon monoxide content in the shift-1 feed is reduced. Table 2 shows pre-reforming reactions.

**Table 2.** Pre-reforming reactions [25].

| | Reaction | ΔH (kJ/mol) | ΔG (kJ/mol) | ΔS (J/kmol) | $T_{Carnot}$ (°C) |
|---|---|---|---|---|---|
| 1 | $C_2H_6 + 2H_2O \rightarrow 2CO + 5H_2$ | 348 | 216 | 441.8 | 514 |
| 2 | $C_3H_8 + 3H_2O \rightarrow 3CO + 7H_2$ | 522 | 283 | 802.5 | 377 |
| 3 | $n\text{-}C_4H_{10} + 4H_2O \rightarrow 4CO + 9H_2$ | 677 | 366 | 1042.3 | 376 |
| 4 | $CH_4 + H_2O \leftrightarrow CO + 3H_2$ | 207 | 143 | 215.44 | 687 |
| 6 | $CO + H_2O \leftrightarrow H_2 + CO_2$ | −42 | −29 | −42.87 | 706 |

Autothermal reforming (ATR)—The autothermal reformer is an adiabatic reactor and is presented in ASPEN HYSYS as an equilibrium reactor; all reactions are also specified as equilibrium reactions. The outputs of a pre-reformer are then preheated to 753 °C and 3000 kPa. Another stream entering the ATR reactor is pure oxygen at 5 °C and 3000 kPa pressure, which is heated by a heater to 200 °C at constant pressure. The output is then cooled or refrigerated before being separated into a syngas component (synthesis gas) and water (stream 11) in a separator (V-101). The combined reforming approach used in this procedure resulted in a steam-to-carbon ratio of 0.6, as lower ratios support the formation of particulate matter and coke, which are unnecessary for the autothermal reform process. Table 3 shows Autothermal reforming reactions.

**Table 3.** Autothermal reforming reactions [25].

| | Reaction | ΔH (kJ/mol) | ΔG (kJ/mol) | ΔS (J/kmol) | $T_{Carnot}$ (°C) |
|---|---|---|---|---|---|
| 1 | $CH_4 + 1.5O_2 \leftrightarrow CO + 2H_2O$ | −522 | −546 | 81.52 | −6670 |
| 2 | $CH_4 + H_2O \leftrightarrow CO + 3H_2$ | 207 | 143 | 215.44 | 687 |
| 3 | $CO + H_2O \leftrightarrow H_2 + CO_2$ | −43 | −30 | −43.93 | 705 |

Methanol synthesis—The synthesis gas that exits the separator is mixed with recycled methanol reactor products, and the blend is pre-heated to 154 °C and roughly 3000 kPa before being compressed by a compressor (K-100) to 8000 kPa and blended with the flash drum recycling stream (stream 26). The combination of the synthesis gas stream and the flash drum recycling stream raises the synthesis gas stream temperature from 209 °C to 270 °C. The methanol synthesis reactor is a plug flow reactor (PFR) (see Figure 7). Every reaction occurring in the reactor, including hydrogenation of carbon monoxide and carbon dioxide, and water gas shift, is exothermic and modelled as a heterogeneous catalytic reaction. The raw methanol (vapour product) at 250 °C and 8000 kPa pressure from the methanol synthesis reactor (plug flow reactor) is flashed in the flash drum (V-100), and the streams from this device are at 30 °C and 8000 kPa pressure. After flashing, V-100 vapour is recycled to maintain a chemically inactive rate inside the circuit. The liquid product from

V-100, predominantly methanol and water, is then sent to the distillation column. Table 4 shows the methanol synthesis reaction.

**Table 4.** Methanol synthesis reactions [25].

| | Reaction | ΔH (kJ/mol) | ΔG (kJ/mol) | ΔS (J/kmol) | $T_{Carnot}$ (°C) |
|---|---|---|---|---|---|
| 1 | $CO + 2H_2 \leftrightarrow CH_3OH$ | −92 | −27 | −222.6 | 140 |
| 2 | $CO + 3H_2 \leftrightarrow CH_3OH + H_2O$ | −50 | 4 | −179.13 | 6 |
| 3 | $CO_2 + H_2 \leftrightarrow H_2O + CO$ | +43 | 29 | 43.89 | 706 |

Here, a $CuO/ZnO/Al_2O_3$ was chosen due to its selectivity of 99%. Table 5 gives the design requirements and catalyst details for the industrial methanol reactor. The reaction rate constants together with the equilibrium rate constants provide ample information on methanol synthesis kinetics. Table A2 (see Appendix A) displays the constants of the reaction rate, adsorption equilibrium, and reaction equilibrium that appear in kinetic expressions.

**Table 5.** Catalyst and reactor data [25,26].

| Parameter | Value |
|---|---|
| Number of tubes | 2962 |
| Density ($kgm^{-3}$) | 1770 |
| Particle diameter (m) | $5.47 \times 10^{-3}$ |
| Heat capacity ($kJ\ kg^{-1}k^{-1}$) | 5 |
| Length of reactor (m) | 7.022 |
| Bed void fraction | 0.39 |
| Density of catalyst bed ($kgm^{-3}$) | 1140 |
| Tube inner diameter (m) | 0.038 |
| Tube outer diameter (m) | 0.042 |

Methanol purification—A distillation column is used in the purification of methanol. The distillation unit's column comprises 20 stages, and the condenser and reboiler pressures are 90 kPa and 7400 kPa, respectively. The bottom streams are made up of 99% water, and 99.5% pure methanol is released at 20 °C and 90 kPa pressure.

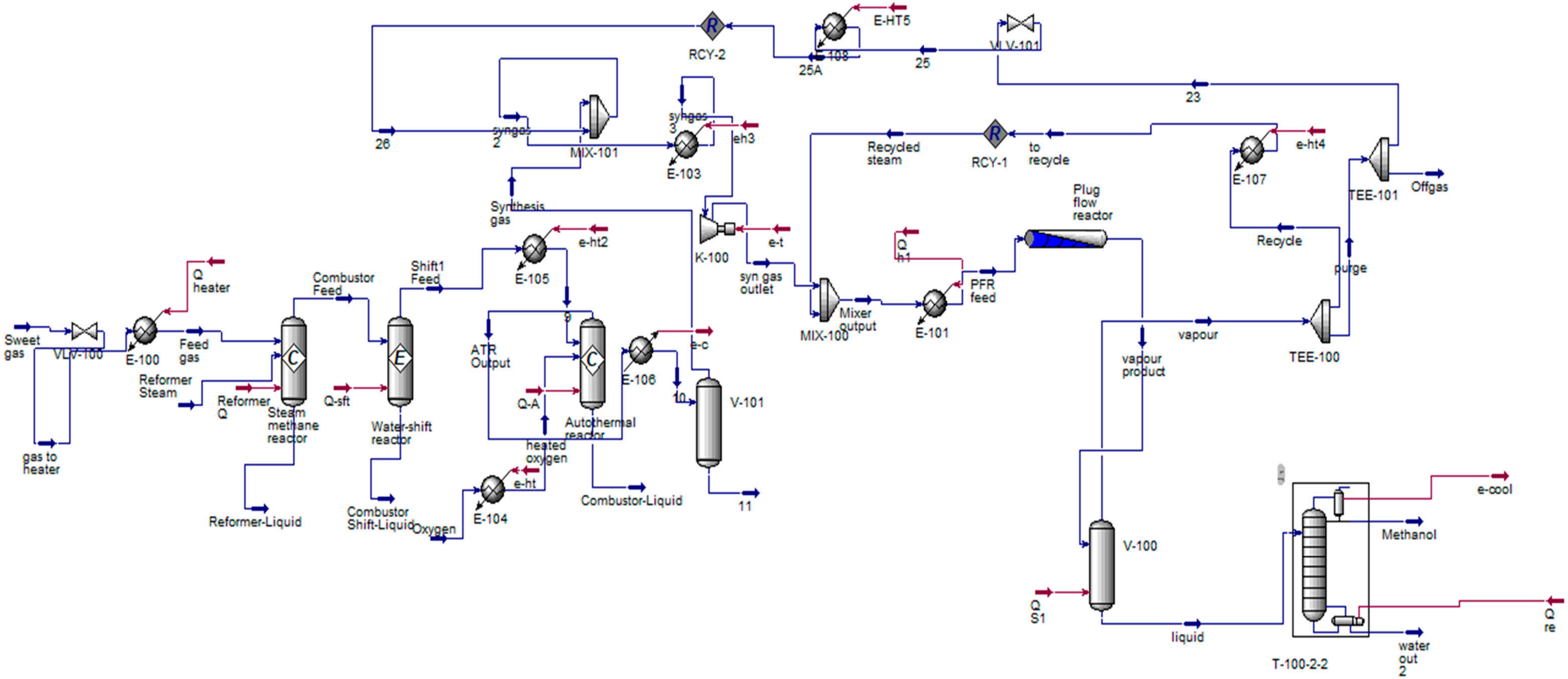


**Figure 6.** GTM process flow diagram in ASPEN HYSYS.

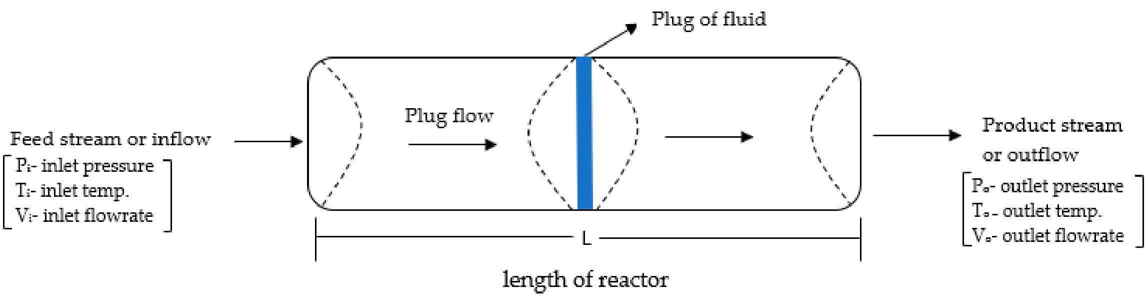


**Figure 7.** Plug flow reactor [27].

## 2.3. Development of ANG Management Framework and Tool

The routine ANG flaring management framework (RAFMF) is a skeletal architecture designed to manage and support reduced gas flaring in oil and gas operations. The gas flaring management framework must be included as a fundamental component for gas flaring regulation, as it determines not only ANG management, but also environmental effects and costs associated with flare emissions. To combat the growing impact of gas flaring, a gas flaring management framework for the petroleum industry in Nigeria (and other gas flaring nations) is required.

The purpose of this section is to design and develop an ANG routine gas flaring management framework and tool prototype for evaluating, using real-time simulations, the best gas flaring processes based on several decisions, their evaluations, and economic viability. This tool will help engineers and operators to decide on which technologies is more effective for reducing gas flaring and its conservation.

### 2.3.1. Proposed Tools and Techniques and Operating Environment

To successfully develop the ANG routine gas flaring management tool, several software tools have been utilised. The tools have been categorised into several phases encountered when developing the application.

MATLAB GUI was used to rapidly prototype and design the layout and user interface for the tool. It was especially useful because development and coding were available using the same MATLAB integrated development environment (IDE).

Aspen HYSYS was used to simulate the various gas flaring processes, which when combined with MATLAB for calculations and analysis, makes for a highly effective gas flaring management tool.

Microsoft's Component Object Model (COM) was used to enable automation and interaction between the main development applications (MATLAB and Aspen HYSYS) programmatically.

### 2.3.2. Development and Implementation

#### Development Methodology

The ANG routine gas flaring management tool prototype consists of a front-end for interfacing with the user and a hybrid backend which comprises a data manipulation and calculation engine and real-time simulations of gas flaring processes.

The tool's main functions have been subdivided into three sub-tools. A procedural programming paradigm was employed when developing the ANG routine gas flaring management tool as each sub-tool relies on the execution of the previous sub-tool. They work together to produce a cohesive tool that directs, maintains, and shares data and user input, ultimately assisting the user in making decisions and comprehending the applications.

#### Implementation

The ANG routine gas flaring management tool has been implemented primarily using the MATLAB UI figure component, which allows for building and designing graphical user interfaces (GUI) using drag and drop controls on the frontend and a backend that allows functionality to be added using familiar MATLAB syntax and functions. The descriptions and functionality of each tool are outlined as follows.

I. Decision Phase Sub-tool

This tool tests the amount of associated natural gas to be flared against the various regulatory criteria to justify as fit for utilisation or not. The average volume of gas produced ($V_P$) and flared ($V_F$) per year in the field are provided as independent variables, while allowable flare volume ($A_V$), carbon emission value of flared gas ($CO_{2(e)}V_F$), and allowable flare volume ($CO_{2(e)}$ $A_V$) are provided as dependent variables (since they depend on $V_P$ and $V_F$ for their evaluation). Furthermore, these variables are employed to answer various regulatory questions that determine if utilisation or conservation of the ANG is required or not based on the conditions highlighted in Figure 8. The Nigerian government has not adopted a particular allowable flare volume to limit the degree of flaring activities carried out by the oil and gas industry [16]. However, the Nigerian Department of Petroleum Resources (DPR) reported in their 2018 annual oil and gas report that 10% of the ANG generated in 2018 was flared [14,16], which represents or assumes the current permissible flare volume rate for oil and gas operations. Here, $A_V$ is set to 10 percent of $V_P$ in this paper, and the $CO_{2(e)}V_F$ equals $V_F \times 54.8$ and $CO_{2(e)}$ $A_V$ equals $A_V \times 54.8$ (1 million standard cubic feet of gas equal 54.8 tonnes of $CO_2$ [28]). Furthermore, to evaluate each condition, this phase solely analyses the $CO_2$ emissions (rather than the ANG compositions) linked with the presumed ANG volumes (assuming that the ANG is flared).

This part of the routine ANG flaring management framework (RAFMF) is crucial because it explains why the volume of ANG flared must be utilised instead. The Decision Phase contains the majority of the regulatory aspects of the framework. If the volume of gas flared is deemed greater than the allowable volume, it signals a need for gas utilisation and moves on to the next stage. Figure 8 shows the decision stage flowchart.

Decision Phase—How It Works

The Decision Phase tool accepts two primary inputs, the gas production ($V_P$) and gas flared ($V_F$). These inputs are stored as global variables, which are then used to calculate a third variable, allowable volume ($A_V$). Using these variables, a series of conditions are evaluated, and their resulting outputs are translated to binary decisions for each condition and indicated with green or red colours using the lamp instrumentation control.

All the conditions are then evaluated together to ultimately decide whether to reduce to target threshold or not. If the decision to reduce to target threshold is positive, the $V_F$ global variable is passed from the Decision Phase sub-tool to the Reduce to Target Threshold sub-tool; if negative, the tool stops running, and a message box is displayed informing the user of the reason.

Decision Phase—The Backend

To decide if gas conservation is required given the input of volume of gas produced and volume of gas flared, the program must evaluate several conditions that make up a decision tree.

II. Reduce to Target Threshold Sub-tool

This stage identifies the target threshold for the RAFMF that must be met. This sets the target threshold (zero-emission) to be achieved and further strengthens the regulatory call for utilising ANG. It compares the existing $V_F$ and the carbon emission value of $V_F$ with the threshold conditions to see if the targets are met. The target threshold conditions for $V_F$, $CO_2$ emission of $V_F$, carbon tax value, and economic value are all indicated in this stage. A basic economic analysis of benefits (amount received from sales of ANG) and costs (arising from ANG flaring penalty) is performed to strengthen the need for evaluating ANG utilisation options. A cost–benefit ratio of one or more indicates that there is a stronger requirement to use $V_F$ and that the benefit of using $V_F$ outweighs the expense of flaring

$V_F$. The selling price of $V_F$ is assumed to be 2.57 per 1000 scf of ANG in USD, while the penalty (cost) of flaring is 2 per 1000 scf of ANG flared in USD [29]. According to the World Bank, one-third of the plants have a carbon tax of less than USD 10 per ton $CO_2$, while the majority have a carbon tax of less than 40 per ton $CO_2$ in USD [30]. Although there is no carbon tax in Nigeria, 20 USD per tonne of $CO_2$ emission is used in this study to assess the impact of a carbon tax.

This stage provides the standard that must be achieved and indicates how much reduction in the existing $V_F$ must be carried out in the next stage by looking at both regulatory and economic aspects. For the reduction to the target threshold to be achieved, the next stage is entered. Figure 9 shows the flowchart to reduce to the target threshold stage.

Reduce to Target Threshold—How It Works

The Reduce to Target Threshold sub-tool accepts the $V_F$ global variable from the Decision Phase sub-tool and is assigned to a corresponding variable on the backend of the Reduce to Target Threshold sub-tool. Using the $V_F$ variable, several conditions are evaluated, and their resulting outputs are translated to binary decisions for each condition. In addition, where necessary, calculations are performed, and their output is displayed in corresponding textbox controls on the form. Finally, all conditions are evaluated, and a decision is made whether to proceed to the Evaluate Options sub-tool or to halt the process.

Reduce to Target Threshold—The Backend

The Reduce to Target Threshold backend evaluates a few conditions in order to determine if gas utilisation or conservation is required and if all target thresholds are met. It then decides whether to terminate the program at this point or proceed to the Evaluate Options phase/sub-tool.

III. Evaluate Options Sub-tool

This stage identifies the best possible ANG utilisation option to achieve the goal and the specified target threshold for the RAFMF. A techno-economic evaluation is used to assess the different ANG utilisation options. This stage comprises the majority of technical and economic aspects. This stage is vital because it helps to ascertain the consequences of the various techniques picked and predict the feasibility of the ANG utilisation project of any oil and gas field for fruitful investment. The technical and economic models are connected to the tool to provide real-time accurate information. Furthermore, the transportation costs of the various processes are assessed and accounted for in the capital investment statement. Revenue and an income and return cost statement are evaluated to produce key economic indicators such as NPV, PBP, ROI, and so on. Figure 10 depicts a flowchart for evaluating options.

Evaluate Option—How It Works

This is the final sub-tool in the process. Here, several economic statements are calculated and tabulated according to the three gas flaring processes (GTM, GTW, and LNG) evaluated. It is necessary to interact with each process simulation in real time to acquire the most accurate data for analysis in the tool.

The illustration in Figure 11 shows how the tool works together with the simulation in real time.

The Evaluate Options user interface was divided into five groupings to reflect the different economic statements and control groups. The groupings are Capital Investment Statement, Operating and Maintenance Cost Statement, Income and Return Cost Statement, Sensitivity Chart section, and a Control section.

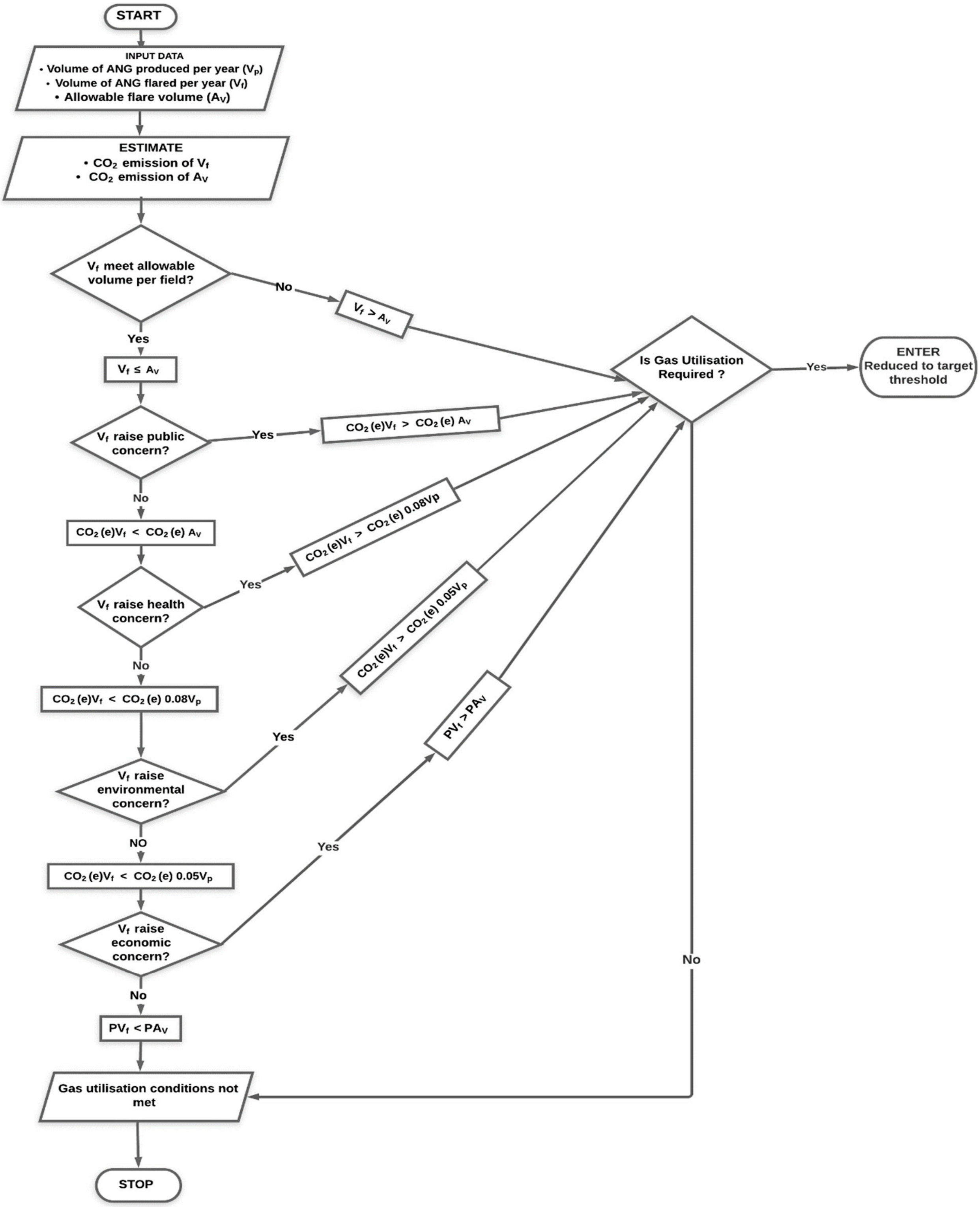


**Figure 8.** Decision Phase flowchart.

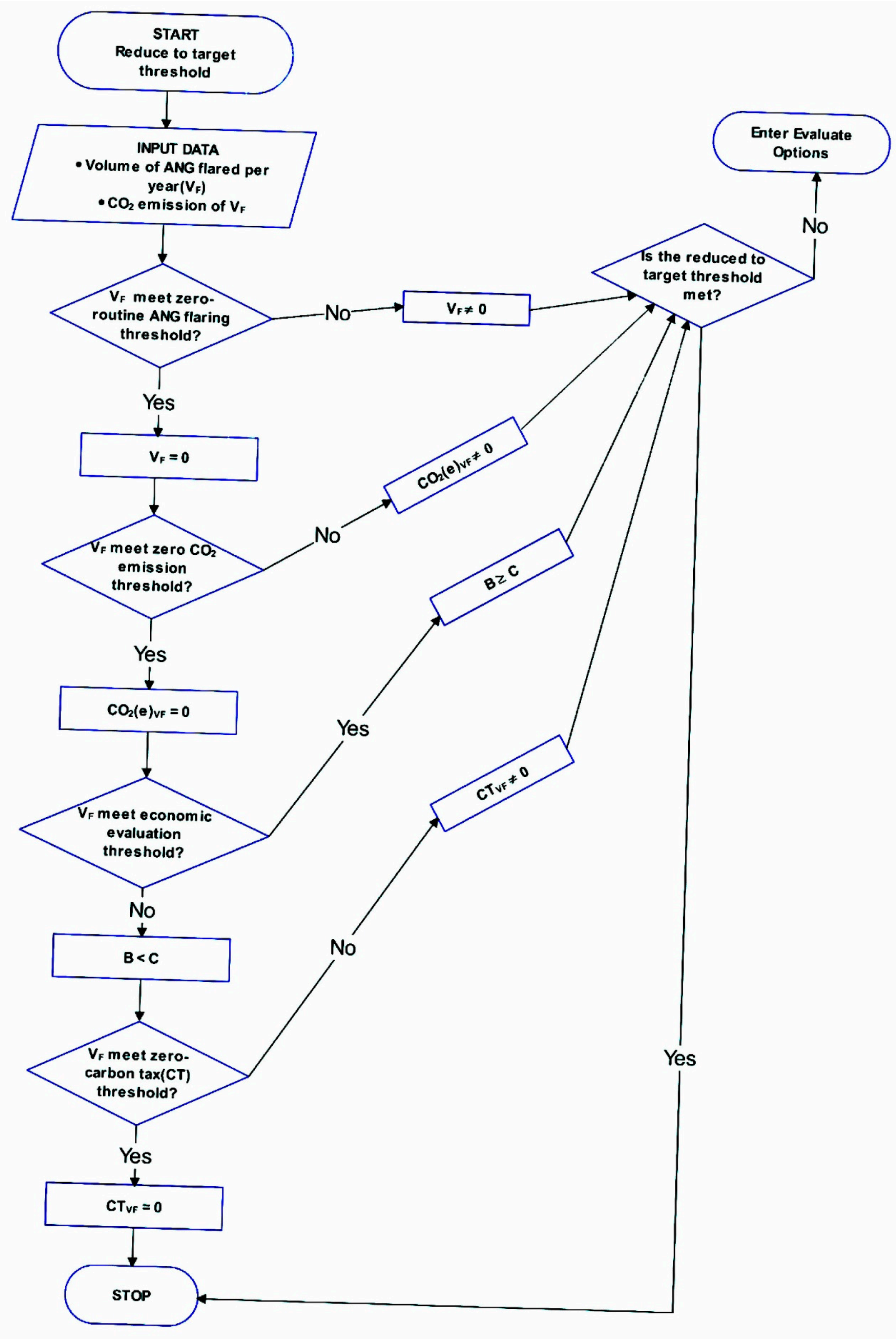


**Figure 9.** Reduce to Target Threshold flowchart.

Evaluate Options Sub-Tool—The Backend

The Evaluate Options backend connects to Aspen HYSYS simulations for each process. It then extracts the final output and calculates a number of economic statements. This is actualised on the backend by the steps outlined and expanded below:

i. Connecting to Aspen HYSYS process simulations in real time.
ii. Connecting to Aspen HYSYS from MATLAB.
iii. Running the corresponding steady-state simulation depending on $V_F$ input.
iv. Obtaining final output from the simulation.
v. Calculating and evaluating economic statements using values from the simulation.

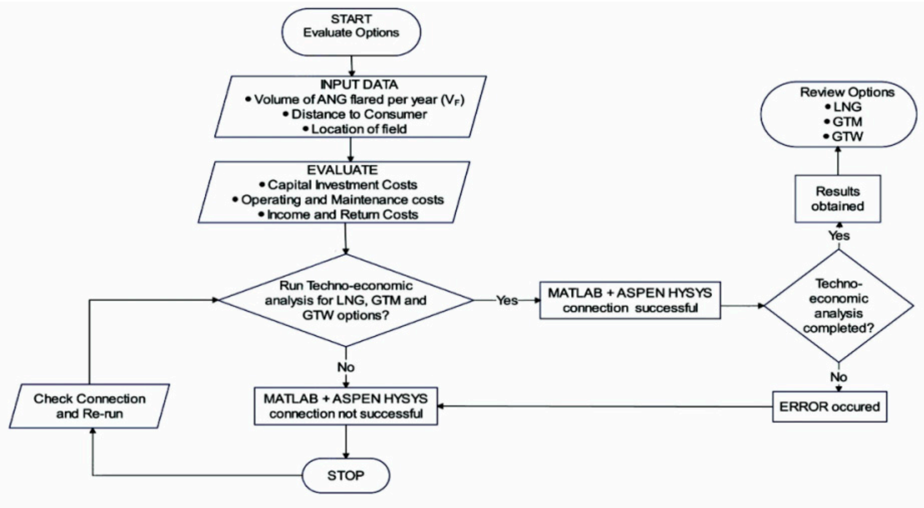


**Figure 10.** Evaluate Options flowchart.

i. Connecting to Aspen HYSYS Process Simulations in Real Time

To connect and interact with the process simulations, the Evaluate Options sub-tool must undergo an initial run. This is where the Microsoft Com interface is initialised and a connection to the process simulations is made. When the tool is run, the simulation process is triggered via the Microsoft Com interface to enable automation and interaction between the management tool program in MATLAB and the process simulation in Aspen HYSYS to provide the necessary/final outputs for evaluating the merits of each process. The illustration in Figure 11 shows the data flow diagram from the frontend to the backend and through the process simulations and finally back at the frontend.

ii. Connecting to Aspen HYSYS from MATLAB

Initially, connecting MATLAB to Aspen HYSYS presented challenges, such as difficulty in developing and applying the ActiveX (a Microsoft software framework) code references (syntax) that supports the interface between MATLAB and Aspen HYSYS software, which was eventually overcome through inputting the proper syntax. Connecting to Aspen HYSYS via MATLAB ActiveX server, the code highlighted below illustrates the creation of an ActiveX object for each process. This is the first step to interacting with Aspen HYSYS from MATLAB. Here, an ActiveX Object for each process is created and then initialised.

iii. Running the Corresponding Steady-State Simulation Depending on VF Input

The $V_F$ variable is evaluated, and if it falls within a certain value range, the corresponding steady-state simulation file on the disk is activated. This is performed for all processes, i.e., GTM, LNG, and GTW.

iv. Getting Final Output from the Simulation

After connecting and running the steady-state simulation files, the program then extracts the final output from the simulation. This final output value is also equivalent to the plant capacity.

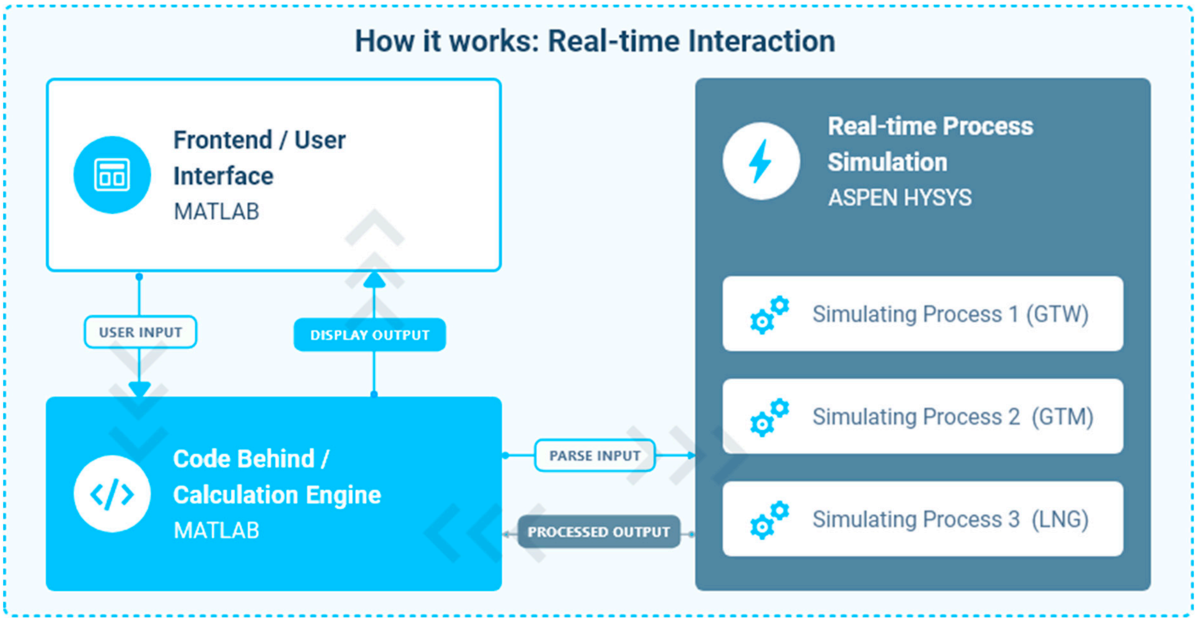


**Figure 11.** Real-time interaction with the process simulations.

v. Evaluating Economic Models

The economic model for the various ANG utilisation methods is developed in this tool to assess the lifecycle economic effect of process choices during conceptual design through the production of capital cost (CAPEX) estimates, operating cost (OPEX) estimates, and revenue (cash inflow) estimates. Cost estimation for key processing units with functioning capacity is always important despite an exact size and uncertain cost details. This method of estimation was achieved by introducing the numerical relation referred to as the six-tenths factor rule (in the absence of specific exponential scaling for the specific units) such that the current piece of equipment is equivalent to one of the various capacities with defined cost data [31]. This relation is mathematically expressed as Equation (1):

$$C_B = C_A\left(\frac{S_B}{S_A}\right)^{0.6} \tag{1}$$

where

$C_B$ = the approximate cost (USD) of equipment having size or capacity $S_B$;
$C_A$ = the known cost (USD) of equipment having corresponding size or capacity $S_A$.

In the absence of cost data for the present year, costs were modified to take account of changing economic conditions by utilising the Chemical Engineering (CE) Plant Cost Index for the present year [31]. This was achieved by applying Equation (2):

$$C_T = C_O\left(\frac{I_T}{I_O}\right) \tag{2}$$

where

$C_T$ = estimated cost at present time $t$;
$C_O$ = cost at previous or original time $t_o$;
$I_T$ = index value at present time $t$;
$I_O$ = index value at time original cost obtained $t_o$.

There are three economic indicators applied in this paper to check the profitability of the various projects. They are net present value (NPV), rate of return on investment (ROR), and payback period (PBP). NPV is used as the primary economic indicator in this research, while the others (PBP and ROR) are used as secondary indicators to check the project's profitability. NPV is preferred over other possibilities because it recognises the time value of money, it avoids the problems associated with accounting adjustments in business projects by using cashflows, and it only indicates the absolute excess of present value of cash inflows over cash outflows.

The NPV estimation technique analyses all the future cashflows using predetermined discount rate and incorporating the effects of inflation into the discounted cashflow calculations to adjust the cashflow forecast using a specific price increase to arrive at the present value, which is then compared with the initial outlay to give either a positive, negative, or zero result. The project with positive NPV is selected. The formula for NPV is given as Equation (3):

$$\mathrm{NPV} = \sum\nolimits_{t-1}^{T} \frac{C_t}{(1+r)^t} - C_0 \tag{3}$$

where

$C_t$ = net adjusted cash inflow during the period $t$;
$C_0$ = total initial investment costs;
$r$ = discount rate;
$t$ = number of periods.

The economic assumptions used in this paper for the application of this tool are 25 years and 10%, 5%, and 20% for the following economic variables: plant life, discount rate, inflation rate, and income tax rate. Table 6 represents the economic formulas applied in this paper (see Appendix A, Table A3 for other economic formulas).

**Table 6.** Calculating and evaluating economic statements.

| Item | Formula |
|---|---|
| Fixed Capital Investment (FCI) | FCI Onshore = (5.04 × EC) + CCT<br>FCI Offshore = (5.14 × EC) + CCT |
| Total Capital Investment (TCI) | TCI= FCI + WC |
| Depreciation (D) | D = (0.1 × FCI) + 0.2 × (0.18 × EC); |
| Operating Labour Cost (OLC) | OLC = Employee per shift (E) × Number of shift (S) × salary per year |
| Operating Cost of Transport (OCT) | OCT = CCT × 0.03; |
| Direct Production Cost (DPC) | DPC = RC + OLC + U+ (0.45 × OLC) + (0.07 × FCI) |
| Fixed Charges (FC) | FC = 0.31 × FCI |
| Manufacturing Cost (MC) | MC = DPC + FC |
| Total Product Cost (TPC) | TPC = MC + (0.9 × OLC) |
| Product Cost for Plant (PCP) | PCP = TPC ÷ PC |
| Total Yearly Income (TYI) | TYI = Plant Capacity (PC) × Plant Cost of Sale (PCS) |
| Gross Profit (GP) | GP = TYI − MC |
| Net Profit (NP) | NP = Gross Profit (GP) × [1 − Income Tax Rate (20%)] = 0.8 × GP |
| Cashflow (CF) | CF = Net Profit (NP) + Depreciation (D) |
| Rate of Return on Investment (ROR) | ROR = Net Cashflow (CF) ÷ Capital Investment × 100% |
| Payback Period (PBP) | PBP = Capital Investment ÷ Net Cashflow (CF) |
| Working Capital (WC) | WC = 0.89 × EC + OCT |
| Capital Recovery Factor (CRF) | CRF = rate ÷ (1 − (1 + rate) ^-period) |
| Total Annualised Cost (TAC) | TAC = (CRF × TCI) + TPC |

Source: Authors' construction based on [31,32].

## 3. Results and Discussion

### *3.1. Process Model Results*

#### 3.1.1. GTW Process Simulation Results

For Field Y, the General Electric (GE) 7F combined natural gas cycle (available in two versions 7F.04 and 7F.05) having a power ranging from 305 MW to 769 MW depending on the plant arrangement and the version was selected. The GE 7F was selected because it provides low electricity costs (cost-effective fuel conversion to electricity) and high combined cycle performance (usually greater than 50%), as well as industry-leading 99.3% reliability, and ensures asset availability [33]. This F-class type also ensures low air pollution (of about 5 ppm $NO_X$ emissions) [33]. For Field X, the Mitsubishi H-100 series gas turbine combined natural gas cycle (available in 50 Hz) having a power ranging from 150 MW to 350 MW, depending on the plant arrangement, was selected because it has a heavy and highly reliable structure designed to ease maintenance and long-term continuous operation. The Mitsubishi H-100 series guarantees high combined cycle efficiency (usually greater than 50%) and possesses a package type that is easy to carry and install [34]. The H-100 series possess a leading air quality control system that ensures low air emissions ($NO_x$, $CO_2$) [34]. The net power outputs for the plants in Fields Y and X are 467 MW and 299 MW, respectively, as shown in Table 7. The average net plant efficiencies (which is equal to the ratio of net power to thermal input multiplied by 100%) for both NGCC plants of Fields Y and X are greater than 50%. The scale factor (0.82 for both Fields Y and X) and load factor (0.60 or 60% for Field Y and 0.85 for Field X) are less than 1. Table 7 shows the overall NGCC plant performance of Fields Y and X.

**Table 7.** Overall NGCC plant performance of Fields Y and X.

| Power Summary | Model Simulation Result for Field Y | Model Simulation Result for Field X |
|---|---|---|
| Gas Turbine Power (MWe) | 303 | 193 |
| Steam Turbine Power (MWe) | 167 | 108 |
| Total Power (MWe) | 471 | 301 |
| Total Auxiliaries (kWe) | 3966 | 2592 |
| Net Power (MWe) | 467 | 299 |
| Net Plant Efficiency (HHV) | 52% | 49.6% |
| Net Plant Efficiency (LHV) | 57% | 54.5% |
| Net Plant Heat Rate (HHV) (kJ/kWh) | 6982 | 7282 |
| Net Plant Heat Rate (LHV) (kJ/kWh) | 6343 | 7254 |
| CONSUMABLES | | |
| Natural Gas Feed Flow (kg/h) | 61,760 | 40,790 |
| Thermal Input (HHV) ($kW_{th}$) | 905,018 | 601,510 |
| Thermal Input (LLV) ($kW_{th}$) | 822,136 | 546,423 |

### 3.1.2. LNG Process Model Result

At −162 °C and 100 kPa pressure, the natural gas for Fields Y and X is cooled to liquid forms with volumes of approximately 580,000 tpa and 380,000 tpa, respectively. Table 8 shows the LNG simulation output for Fields Y and X.

**Table 8.** LNG simulation output for Fields Y and X.

| Parameter | Model Simulation Output for Field Y | Model Simulation Output for Field X |
|---|---|---|
| LNG Output | | |
| LNG Output Feed Rate (tpa) | 580,000 | 380,000 |

### 3.1.3. GTM Process Simulation Results

At 9 °C temperature and 90 kPa pressure, methanol with 99.5 percent purity was produced from the feed gas volume (26,493 MMscf) and fed into the GTM process for Field Y, with an output volume of approximately 0.7 million tonnes per annum (Mtpa), whereas methanol (99.5% purity) with an output volume of approximately 0.4 Mtpa was produced for Field X (with feed gas volume of 17,247 MMscf) at 24 °C temperature and 90 kPa. Synthesis gas of output volumes of 94,749 MMscf and 61,062 MMscf was generated in Fields Y and X, respectively, at 17 °C temperature and 2995 kPa pressure. At 9 °C temperature and 90 kPa pressure, methanol with 99.5 percent purity was produced from the feed gas volume (26,493 MMscf) fed into the GTM process for Field Y, with an output volume of approximately 0.7 Mtpa. Synthesis gas of output volumes of 94,749 MMscf was generated in Field Y at 17 °C temperature and 2995 kPa pressure. Table 9 shows the properties of gas produced and GTM simulation outputs for Field Y.

**Table 9.** Properties of the gases produced after the simulation for Fields Y and X.

| | Field Y | | | Field X | | |
|---|---|---|---|---|---|---|
| | Synthesis Gas | Methanol | Off-Gas | Synthesis Gas | Methanol | Off-Gas |
| Conditions | | | | | | |
| Mass flow (kgmole/h) | 12,930 | 3053 | 873.5 | 8333 | 1952 | 329 |
| Pressure (kPa) | 2995 | 90 | 7400 | 2995 | 90 | 7400 |
| Temperature (°C) | 17 | 9 | 40 | 17 | 24 | 40 |
| Mole Fraction | | | | | | |
| Methane | - | - | - | - | - | - |
| Ethane | 0.006 | - | 0.292 | 0.012 | - | 0.292 |
| Propane | 0.001 | - | 0.050 | 0.001 | - | 0.049 |
| n-Butane | - | - | 0.037 | - | - | 0.035 |
| Carbon dioxide | 0.251 | 0.005 | 0.040 | 0.258 | 0.005 | 0.071 |
| Carbon Monoxide | 0.017 | - | 0.457 | 0.008 | - | 0.434 |
| Hydrogen | 0.720 | - | - | 0.718 | - | - |
| Water | - | - | - | - | - | - |
| Nitrogen | 0.003 | - | 0.118 | 0.003 | - | 0.112 |
| Methanol | - | 0.9950 | 0.006 | - | 0.9950 | 0.007 |

### *3.2. ANG Management Tool Simulation Result*

#### 3.2.1. For Field Y

The Decision Phase analysis (see Figure 12) indicates that the ANG to be flared ($V_F$ = 26,493 MMscf) should be utilised rather than flared after comparing the ANG flare volume carbon emission value to the regulatory standards assumed for this ANG management tool. This step is then followed by the Reduce to Target Threshold phase. The Reduce to Target Threshold phase (see Figure 12) establishes the target threshold (zero-emission) to be attained and enhances the regulatory case for utilising the ANG flare volume for field B. To emphasise the necessity for analysing ANG utilisation choices, a basic economic analysis of benefit (amount gained if ANG is collected and sold instead of flared (USD 68M)) and cost (arising from ANG flaring penalty (53M USD)) ratio was performed. To examine the impact of a carbon tax, the carbon tax price was set at 20 per ton of $CO_2$ emissions in USD (a carbon tax of 29M USD is incurred). This step was then followed by the Evaluate Options phase (see Figure 12). The Evaluate Options phase is where the optimum choice for gas utilisation is examined using techno-economic analysis (via the combination of MATLAB and Aspen HYSYS simulation software) to assure the most economical route for investment. Furthermore, the transport cost and the key economic indicators for the various ANG utilisation options are evaluated in this phase. Figure 12 was obtained from the MATLAB simulation software/tool.

#### 3.2.2. For Field X

The Decision Phase analysis (see Figure 13) indicated that the ANG to be flared ($V_F$ = 17,247 MMscf) should be used rather than flared after comparing the ANG flare volume carbon emission value to the regulatory standards assumed for this ANG management tool. The allowable volume ($A_V$) and the carbon emission value for $V_F$ and $A_V$ are evaluated as 2734 MMscf, 945,136 tonnes and 149,812 tonnes, respectively. This step was then followed by the Reduce to Target Threshold phase. The Reduce to Target Threshold phase (see Figure 13) establishes the target threshold (zero-emission) to be attained and enhances the regulatory case for utilising the ANG volume (17,247 MMscf). To emphasise the necessity for analysing ANG utilisation choices, a basic economic analysis of benefit (amount gained from ANG sales (USD 44M)) and cost (arising from ANG flaring penalty

(USD 34M)) was performed. To examine the impact of a carbon tax, the carbon tax price was set at USD 20 per ton of $CO_2$ emissions (a carbon tax of USD 19M is incurred). This step was then followed by the Evaluate Options phase (see Figure 13). The Evaluate Options phase is where the optimum choice for gas utilisation is examined using techno-economic analysis (via the combination of MATLAB and Aspen HYSYS simulation software) to assure the most economical route for investment. Furthermore, the transport cost (both capital and operating transport costs), equipment cost (93M, 113M, and 173M for GTM, GTW, and LNG, respectively), and the economic indicators (see Table 10 for summary), amongst others, for the various ANG utilisation options are evaluated in this phase. Figure 13 shows the simulation results of the various phases obtained from the MATLAB simulation tool.

**Table 10.** Summary of key results for Fields Y and X having a useful lifetime of 25 years.

| **Cost Items** | **LNG** | | **GTW** | | **GTM** | |
|---|---|---|---|---|---|---|
| | Field Y | Field X | Field Y | Field X | Field Y | Field X |
| Key Financial Indicators | | | | | | |
| Rate of Return of Investment (%) | 10 | 4 | 7 | 9 | 7 | 1 |
| Payback Period (yr.) | 10.24 | 25.43 | 14.25 | 11.19 | 13.85 | 98.32 |
| Net Present Value (M USD) | 210 | −568 | −164 | 31 | −114 | −498 |

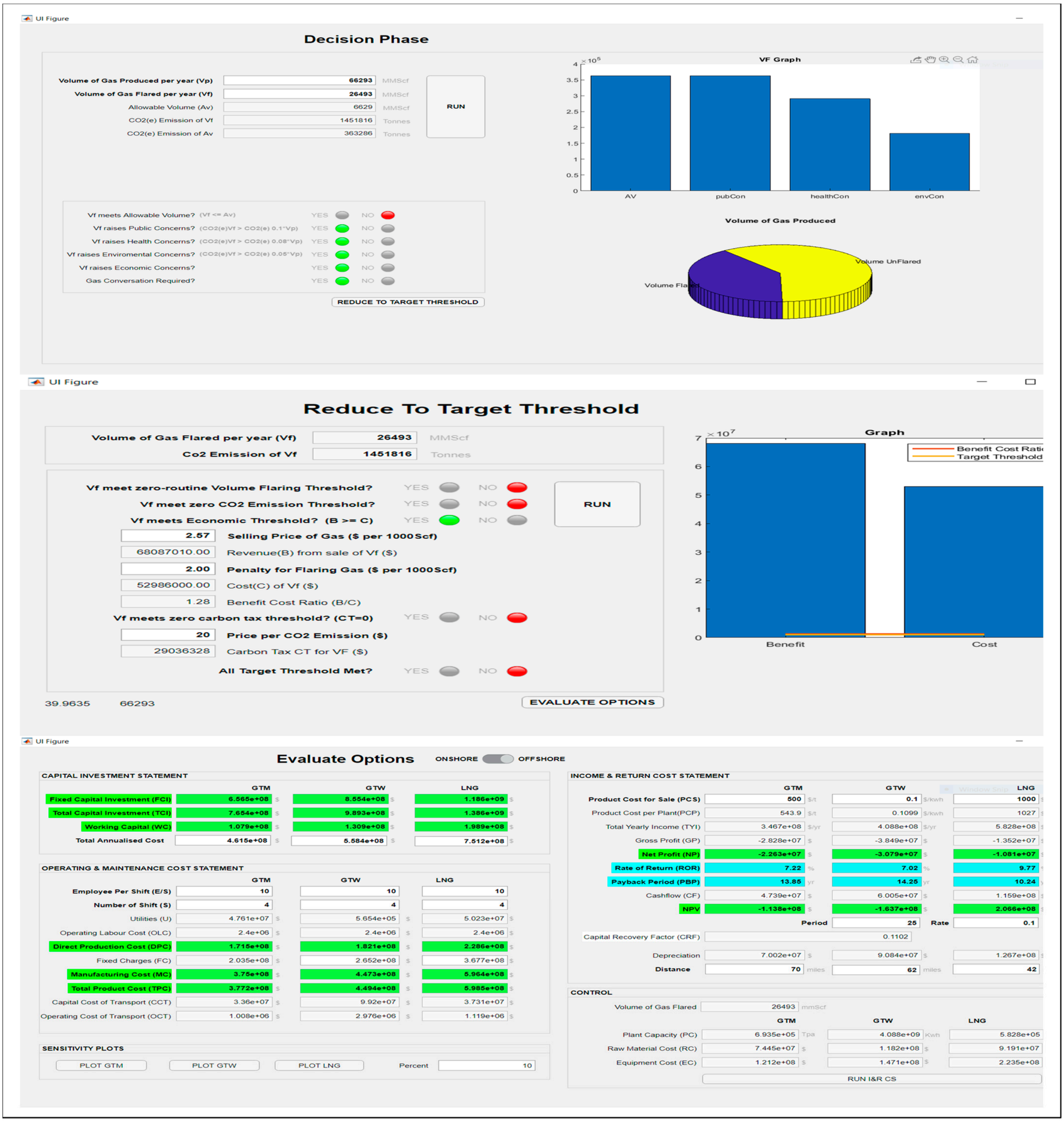

**Figure 12.** Decision Phase, Reduce to Target Threshold phase, and Evaluate Options phase for Field Y.

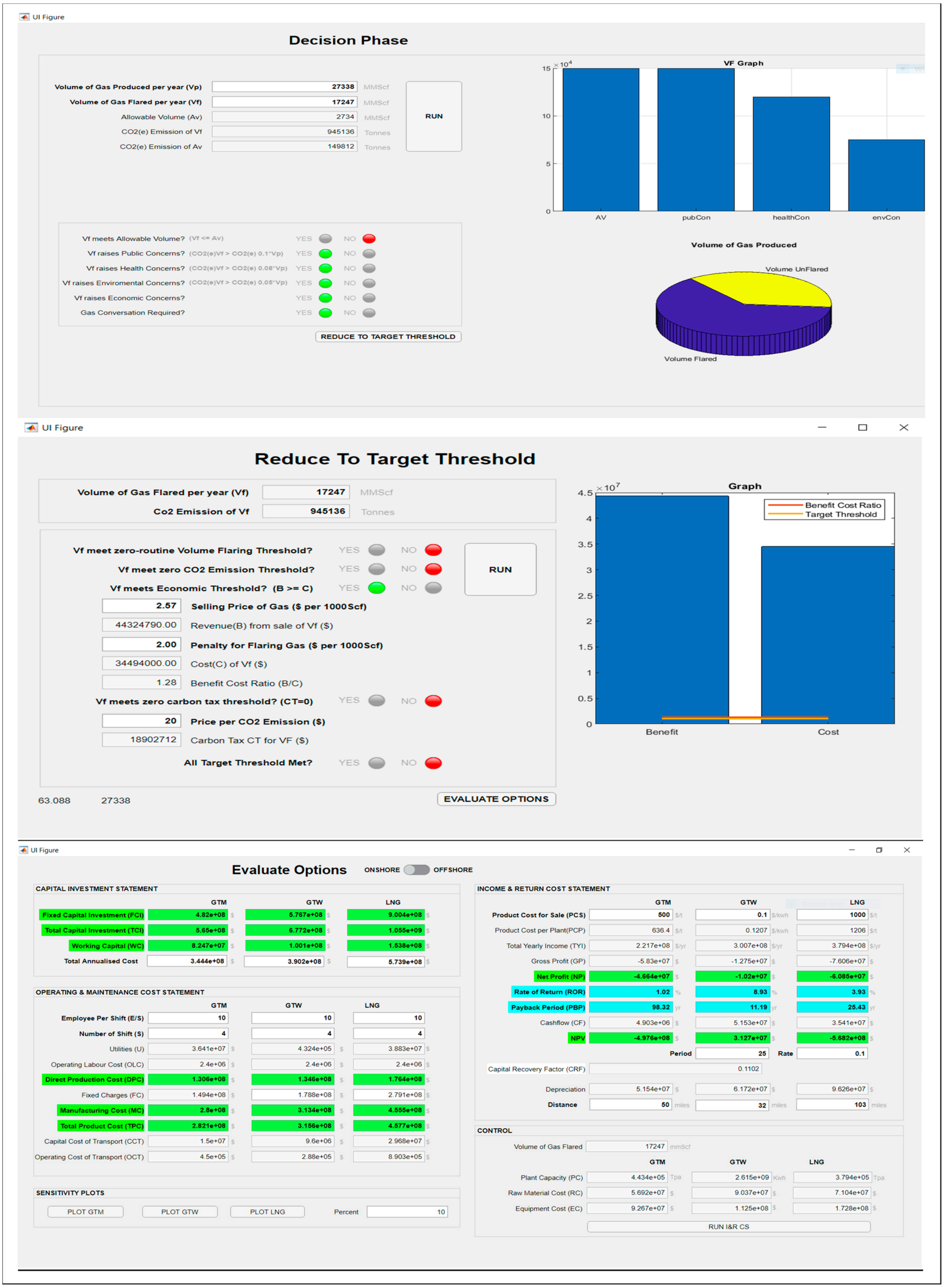


**Figure 13.** Decision Phase, Reduce to Target Threshold phase, and Evaluate Options phase for Field X.

## 4. Conclusions

Techno-economic models for the selected ANG utilisation processes (LNG, GTW, and GTM) were developed. A routine ANG flaring management framework which combined regulatory, technical, and economic analysis to reach optimal decisions broke the process down into three phases, which were the Decision Phase, Reduce to Target Threshold, and Evaluate Options. A routine ANG flaring gas management tool was developed and prepared for testing within certain ranges of parameters and constraints meeting the aim of the study.

The application of the tool for this paper was carried out with techno-economic analysis, using data obtained from Fields Y (offshore field in the South-South Niger Delta, Rivers State) and X (onshore field in the South-West Niger Delta, Delta State) in the Niger Delta region of Nigeria. The application was made feasible by connecting the tool to the Aspen HYSYS process simulations via MATLAB Active X server. According to the process simulations and economic evaluations carried out on the fields, the following output was observed for each of the fields.

For Field Y, the LNG process was seen to be the most profitable as it was closer to the LNG pipeline infrastructure and had high product demand, positive NPV, high investment return, and shortest payback period. Although the LNG process was more expensive than the GTW and GTM processes, this was balanced out by its high annual profit and proximity to a market (in terms of distance). Furthermore, GTW technology was chosen for Field X as it is close to the electrical grid, thereby having high grid export capability and the high requirements for electricity in that area. Further economic considerations included positive NPV, low payback period, and high investment returns.

Field Y has a higher flare gas volume (flare more gas) than Field X, so the capital investment costs (both fixed and total costs) are higher for Field Y, due to its offshore location because of additional costs associated with equipment and increased transport costs. Field X has lower capital investment costs compared to Field Y due to its onshore location and lower flare gas volume.

When applying crucial environmental considerations for each field, GTM could be chosen (provided that it is economically viable) owing to its ability to produce clean fuel; however, when the ANG volume for a field is low, LNG and GTM processes become less than ideal. The results obtained as presented and discussed show the successful testing of the tool as well as its feasibility and potential for large-scale application. Further research and optimisation of the tool, however, are necessary to achieve better results with consistent use. The tool has several advantages, including the ability to set practical limits for allowable volumes of gas flared during oil and gas operations and to conduct a real-time comparison study of the economic sanctions (such as carbon tax and flaring fines) incurred because of ANG flaring and the economic benefits received through the adoption of various gas utilisation alternatives for optimal decision making.

We developed and applied a working ANG flaring management tool that uses techno-economic analysis to select appropriate ANG utilisation techniques based on their technical and economic feasibility. We developed a routine ANG flaring management framework unique to Nigeria, which was then used to develop an ANG flaring management tool, the first of its kind (a first step towards a decision aid, but it is not yet a decision aid) in Nigeria that incorporates field data to provide real-time ANG utilisation outputs for investment decisions. In doing so, our goal of developing a systematic framework and management tool to reduce routine gas flaring through ANG utilisation, promote the economic benefits of ANG utilisation, and minimise carbon dioxide emission was achieved through the successful accomplishment of the various objectives set out. For future research, the following are recommended for the improvement of the ANG flaring management tool and this work.

The addition of more regional profiles in West Africa and elsewhere in the world (which would require the acquisition of relevant data) should be considered to reflect the exact regulatory, technical, and economic parameters of the various regions required for analysis.

The addition to the tool of more ANG utilisation such as natural gas to fertiliser, compressed natural gas (CNG), and natural gas to hydrogen utilisation options should be implemented to increase the number of options available for selection.

The incorporation of dynamic state simulations that incorporate high levels of detailed modelling, encourage significant reductions in high CAPEX, and provide high levels of process analysis should be investigated for the tool.

An investigation into the various impacts of ANG flaring on community health and workplace safety (such as methane explosion, CO poisoning, and so on) should also be considered.

Outlook: This paper was originally designed with some technologies (GTW, GTL, and LNG) to end routine gas flaring or venting in the context of Nigerian gas flaring so that different stakeholders can utilise this tool to end these wasteful, polluting industrial practices. This tool can be easily deployed for other emerging technologies such as "gas to hydrogen" and "gas to X". The business implications of this tool with selected technologies can be utilised from the perspective of other countries.

**Author Contributions:** Conceptualisation and methodology, R.A., K.P., N.S. and E.J.A.; writing—original draft and editing, R.A.; writing—review, K.P., R.A., N.S. and E.J.A.; supervision, K.P. and N.S. All authors have read and agreed to the published version of the manuscript.

**Funding:** The authors would like to thank Cranfield University for supporting Robin Abu's PhD programme.

**Institutional Review Board Statement:** Not applicable.

**Informed Consent Statement:** Not applicable.

**Data Availability Statement:** The authors confirm that the data supporting the findings of this study are available within the article.

**Conflicts of Interest:** The authors declare no conflict of interest.

## Appendix A

**Table A1.** Gas Production And Flare Volumes (Mmscf).

| Field Name | Month | 2014 | | | 2015 | | | 2016 | | | 2017 | | | 2018 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Gas Produced | Gas Flared | Gas Used | Gas Produced | Gas Flared | Gas Used | Gas Produced | Gas Flared | Gas Used | Gas Produced | Gas Flared | Gas Used | Gas Produced | Gas Flared | GAS Used | AVR. GAS. PROD. | AVR.GAS FLARED |
| | JAN | 2633.61 | 2616.53 | 17.08 | 3900.61 | 2596.44 | 1304.17 | 2091.46 | 842.66 | 1248.80 | 1386.56 | 883.96 | 502.60 | 2326.03 | 1782.78 | 543.25 | 2467.65 | 1744.47 |
| | FEB | 2495.57 | 2479.12 | 16.45 | 3532.55 | 2354.66 | 1177.89 | 1814.82 | 746.76 | 1068.06 | 2617.23 | 1500.1 | 1117.13 | 2140.95 | 1617.7 | 523.25 | 2520.22 | 1739.67 |
| | MAR | 186.97 | 168.7 | 18.27 | 3888.36 | 2584.19 | 1304.17 | 2046.94 | 864.5 | 1182.44 | 3208.59 | 1956.92 | 1251.67 | 2155.79 | 1614.97 | 540.82 | 2297.33 | 1437.86 |
| | APR | 2402.47 | 2384.83 | 17.64 | 3063.76 | 2070.67 | 993.09 | 1961.33 | 854.63 | 1106.7 | 3078.53 | 1827.42 | 1251.11 | 1864.66 | 1410.15 | 454.51 | 2474.15 | 1709.54 |
| | MAY | 2392.32 | 2374.68 | 17.64 | 3650.85 | 2346.68 | 1304.17 | 1974.77 | 792.33 | 1182.44 | 511.77 | 332.15 | 179.62 | 2147.74 | 1641.71 | 506.03 | 2135.49 | 1497.51 |
| Field X | JUN | 1734.32 | 1716.68 | 17.64 | 3181.57 | 2048.2 | 1133.37 | 1778.98 | 655.69 | 1123.29 | 629.58 | 611.94 | 17.64 | 2122.61 | 1603.42 | 519.19 | 1889.41 | 1327.19 |
| | JUL | 1411.13 | 1399.37 | 11.76 | 2449.86 | 1544.41 | 905.45 | 1475.04 | 553.56 | 921.48 | 1644.44 | 1309.07 | 335.37 | 2730.21 | 2193.94 | 536.27 | 1942.14 | 1400.07 |
| | AUG | 3616.83 | 2288.16 | 1328.67 | 3538.71 | 458.99 | 3079.72 | 1734.88 | 675.99 | 1058.89 | 2132.83 | 1558.34 | 574.49 | 2223.06 | 1691.27 | 531.79 | 2649.26 | 1334.55 |
| | SEP | 3433.64 | 2185.47 | 1248.17 | 2156.42 | 216.51 | 1939.91 | 623.63 | 605.99 | 17.64 | 2173.99 | 1632.05 | 541.94 | 2104.76 | 516.88 | 1587.88 | 2098.49 | 1031.38 |
| | OCT | 3837.19 | 2543.66 | 1293.53 | 2220.54 | 212.73 | 2007.81 | 120.19 | 883.75 | −763.56 | 2313.85 | 1774.99 | 538.86 | 2187.29 | 1644.01 | 543.28 | 2135.81 | 1411.83 |
| | NOV | 3436.02 | 2184.21 | 1251.81 | 1813.49 | 231.07 | 1582.42 | 1953.91 | 792.89 | 1161.02 | 2188.48 | 1667.33 | 521.15 | 1892.17 | 1383.13 | 509.04 | 2256.81 | 1251.73 |
| | DEC | 3741.71 | 2464.84 | 1276.87 | 2106.44 | 209.51 | 1896.93 | 2003.61 | 719.88 | 1283.73 | 2345.63 | 1794.73 | 550.9 | 2158.59 | 1615.41 | 543.18 | 2471.2 | 1360.87 |
| | | **31,321.78** | **24,806.25** | **6515.53** | **35,503.16** | **16,874.06** | **18,629.10** | **19,579.56** | **8988.63** | **10,590.93** | **24,231.48** | **16,849.00** | **7382.48** | **26,053.86** | **18,715.37** | **7338.49** | **27,338** | **17,247** |
| | | | **79%** | | | **48%** | | | **46%** | | | **70%** | | | **72%** | | | |
| | JAN | 5502.66 | 4388.37 | 1114.29 | 4966.13 | 2176.88 | 2789.25 | 6537.76 | 2207.46 | 4330.3 | 7010.16 | 1792.47 | 5217.69 | 4683.32 | 1602.74 | 3080.58 | 5740.01 | 2433.58 |
| | FEB | 4461.2 | 3629.31 | 831.89 | 5118.08 | 1413.9 | 3704.18 | 5628.88 | 2116.75 | 3512.13 | 6190.96 | 1795.32 | 4395.64 | 4688.34 | 1464.68 | 3223.66 | 5217.49 | 2083.99 |
| | MAR | 4499.17 | 3808.73 | 690.44 | 5907.64 | 1979.748 | 3927.892 | 6067.39 | 2100.02 | 3967.37 | 5295.55 | 2099.81 | 3195.74 | 4705.8 | 1720.24 | 2985.56 | 5295.11 | 2341.71 |
| | APR | 4251.44 | 3530.11 | 721.33 | 6340.1 | 1934.39 | 4405.71 | 5227.58 | 2037.62 | 3189.96 | 4427.35 | 2039.21 | 2388.14 | 4155.39 | 1817.66 | 2337.73 | 4880.37 | 2271.8 |
| | MAY | 6316.15 | 3251.22 | 3064.93 | 6527.19 | 2061.74 | 4465.45 | 6656.75 | 2093.38 | 4563.37 | 5047.82 | 2081.43 | 2966.39 | 3903.69 | 1661.44 | 2242.25 | 5690.32 | 2229.84 |
| Field Y | JUN | 4446.84 | 4156.42 | 290.42 | 6684.25 | 2130.41 | 4553.84 | 5888.48 | 1936.1 | 3952.38 | 5206.2 | 1973.02 | 3233.18 | 3571.89 | 1592.83 | 1979.06 | 5159.53 | 2357.76 |
| | JUL | 6791.07 | 1870.4 | 4920.67 | 6123.44 | 2094.35 | 4029.09 | 3745.85 | 1752.91 | 1992.94 | 5032.54 | 1921.27 | 3111.27 | 3936.91 | 1376.06 | 2560.85 | 5125.96 | 1803 |
| | AUG | 7865.55 | 1831.26 | 6034.29 | 6449.4 | 2122.88 | 4326.52 | 6061.53 | 2030.16 | 4031.37 | 4624.39 | 1733.27 | 2891.12 | 4187.68 | 1447.27 | 2740.41 | 5837.71 | 1832.97 |
| | SEP | 7541.36 | 2010.36 | 5531 | 5656.83 | 1673.77 | 3983.06 | 5799.31 | 1944.96 | 3854.35 | 4571.11 | 1645.13 | 2925.98 | 3940.45 | 11480 | -7539.55 | 5501.81 | 3750.84 |
| | OCT | 7931.64 | 2270.93 | 5660.71 | 6447.38 | 1879.84 | 4567.54 | 6543.56 | 1660.9 | 4882.66 | 4865.61 | 1643.86 | 3221.75 | 4282.96 | 1518.21 | 2764.75 | 6014.23 | 1794.75 |
| | NOV | 7433.43 | 2117.8 | 5315.63 | 6678.17 | 1903.42 | 4774.75 | 7224.61 | 1982.03 | 5242.58 | 4705.64 | 1528.01 | 3177.63 | 4161.82 | 1434.17 | 2727.65 | 6040.73 | 1793.09 |
| | DEC | 7817.14 | 2380.63 | 5436.51 | 6708.5 | 2110.04 | 4598.46 | 5220.51 | 1691.78 | 3528.73 | 4998.9 | 1274.27 | 3724.63 | 4203.41 | 1542.24 | 2661.17 | 5789.69 | 1799.79 |
| | | **74,857.65** | **35,245.54** | **39,612.11** | **73,607.11** | **23,481.37** | **50,125.74** | **70,602.21** | **23,554.07** | **47,048.14** | **61,976.23** | **21,527.07** | **40,449.16** | **50,421.66** | **28,657.54** | **21,764.12** | **66,293** | **26,493** |
| | | | **47%** | | | **32%** | | | **33%** | | | **35%** | | | **57%** | | | |

**Table A2.** Kinetic and equilibrium constants [25,26].

| k = A exp(B/RgT) | A | B |
|---|---|---|
| Ka $(bar^{-1/2})$ | 0.499 | 17,197 |
| Kb $\left(bar^{-1}\right)$ | $6.62 \times 1011$ | 124,119 |
| Kc | 3453.38 | - |
| kd $(mol/kg\ s\ bar^2)$ | 1.07 | 36,696 |
| Ke $(mol/kg\ s\ bar)$ | $1.22 \times 1010$ | −94,765 |
| Keq = $10^{\left(\frac{A}{T}-B\right)}$ | A | B |
| $k_1^{eq1}$ (bar − 2) | 3066 | 10.592 |
| $k_2^{eq1}$ | 2073 | 2.029 |

Source: Authors' construction based on data collected from DPR in Nigeria.

**Table A3.** Other economic formulas (authors' construction based on [35–39]).

| Item | Formula |
|---|---|
| Plant Capacity (PC)<br>This is the final output from the simulation | %GTM<br>PCGTM = GTM_Final_A;<br>%GTW<br>PCGTW = GTW_Final*8760;<br>%LNG<br>PCLNG = LNG_Final; |
| Raw Material Cost (RMC) | % GTW<br>$RMC_{GTW} = RMC_{GTW}{}^1 \times [PC_{GTW}/PC_{GTW}{}^1]^{0.6}$<br>% GTM<br>$RMC_{GTM} = RMC_{GTM}{}^1 \times [PC_{GTM}/PC_{GTM}{}^1]^{0.6}$<br>% LNG<br>$RMC_{LNG} = RMC_{LNG}{}^1 \times [PC_{LNG}/PC_{LNG}{}^1]^{0.6}$<br><br>N/B—$GTM^1$, $GTW^1$, and $LNG^1$ are ANG processes that have established capacities and costs. |
| Equipment Cost (EC) | % GTW<br>$EC_{GTW} = EC_{GTW}{}^1 \times [PC_{GTW}/PC_{GTW}{}^1]^{0.6}$<br>% GTM<br>$EC_{GTM} = EC_{GTM}{}^1 \times [PC_{GTM}/PC_{GTM}{}^1]^{0.6}$<br>% LNG<br>$EC_{LNG} = EC_{LNG}{}^1 \times [PC_{LNG}/PC_{LNG}{}^1]^{0.6}$<br>N/B—$GTM^1$, $GTW^1$, and $LNG^1$ are ANG processes that have established capacities and costs. |
| Capital Cost of Transport (CCT) | For GTM<br>CCT Onshore—USD 300,000 × Distance (D) (cost per mile of pipeline assuming 12 inch)<br>CCT Offshore—USD 480,000 × Distance (D)<br>For GTW<br>CCT Onshore—USD 300,000 × Distance (D) (cost per mile assuming transmission via 65 kV lines)<br>CCT Offshore—USD 1,600,000 × Distance (D)<br>For LNG<br>CCT Offshore<br>C = 1.40 + 0.0002(D)<br>CCT Onshore<br>C = 1.70 + 0.0002(D)<br>Where C = Cost per 1000 scf<br>D = Distance in miles<br>Therefore, CCT = [C × Volume flared ($V_F$) × 1000] (assumed LNG Carrier price per volume) |

**Table A3.** *Cont.*

| Item | Formula |
| --- | --- |
| Utilities (U) | % GTW<br>$U_{GTW} = U_{GTW}{}^{1} \times [PC_{GTW}/PC_{GTW}{}^{1}]^{0.6}$<br>% GTM<br>$U_{GTM} = U_{GTM}{}^{1} \times [PC_{GTM}/PC_{GTM}{}^{1}]^{0.6}$<br>% LNG<br>$U_{LNG} = U_{LNG}{}^{1} \times [PC_{LNG}/PC_{LNG}{}^{1}]^{0.6}$<br>N/B—$GTM^1$, $GTW^1$, and $LNG^1$ are ANG processes that have established capacities and costs. |

## References


1. Jorgenson, A.K. Global warming and the neglected greenhouse gas: A cross-national study of the social causes of methane emissions intensity, 1995. *Soc. Forces* **2006**, *84*, 1779–1798. [CrossRef]
2. Kearns, J.; Armstrong, K.; Shirvill, L.; Garland, E.; Simon, C.; Monopolis, J. Flaring and venting in the oil and gas exploration and production industry, international association of oil. *Gas Prod. Rep.* **2000**, *2*, 288.
3. Shore, D. Making the flare safe. *J. Loss Prev. Process Ind.* **1996**, *9*, 363–381.
4. Ngene, S.; Tota-Maharaj, K.; Eke, P.; Hills, C. Environmental and economic impacts of crude oil and natural gas production in developing countries. *Int. J. Econ. Energy Environ.* **2016**, *1*, 64–73.
5. EPA. *Air Pollution Cost Manual*, 6th ed.; EPA/452/B-02-001; U.S. Environment Protection Agency: Washington, DC, USA, 2002.
6. Wang, D.; Bao, A.; Kunc, W.; Liss, W. Coal power plant flue gas waste heat and water recovery. *Appl. Energy* **2012**, *91*, 341–348. [CrossRef]
7. Roosa, S.A.; Jhaveri, A.G. *Carbon Reduction: Policies, Strategies, and Technologies*; River Publishers: Gistrup, Denmark, 2020.
8. Creamer, A.E.; Gao, B. *Carbon Dioxide Capture: An Effective Way to Combat Global Warming*; Springer: Cham, Switzerland, 2015.
9. Svensson, B. Global gas flaring-a burning issue. In Proceedings of the 20th World Petroleum Congress, OnePetro, Doha, Qatar, 4–8 December 2011.
10. Odumugbo, C.A. Natural gas utilisation in Nigeria: Challenges and opportunities. *J. Nat. Gas Sci. Eng.* **2010**, *2*, 310–316. [CrossRef]
11. EIA. How Much Carbon Dioxide Is Produced When Different Fuels Are Burned? Energy Information Administration, Office of Oil and Gas, 2021. Available online: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 (accessed on 10 August 2022).
12. IEA. Global Energy and CO2 Status Report 2019. International Energy Agency, Paris, 2019. Available online: https://www.iea.org/reports/global-energy-co2-status-report-2019 (accessed on 10 September 2022).
13. Funds, H. The Growing Importance of Natural Gas. *Nat. Gas White Pap.* **2014**, 1–8. Available online: https://www.raymondjames.com/neunuebelbarrantes/pdfs/natural_gas_may_2014.pdf (accessed on 15 August 2022).
14. PriceWaterhouseCoopers (PwC). Assessing the Impact of Gas Flaring on the Nigerian Economy. 2019. Available online: https://www.pwc.com/ng/en/assets/pdf/gas-flaring-impact1.pdf (accessed on 7 August 2022).
15. Organisation of the Petroleum Exporting Countries (OPEC) Website, 2021. Available online: https://www.opec.org/opec_web/en/about_us/167.htm (accessed on 9 August 2022).
16. Department of Petroleum Resources (DPR). *Annual Oil and Gas Report*; Ministry of Petroleum in Nigeria: Abuja, Nigeria, 2018.
17. Ajugwo, A.O. Negative effects of gas flaring: The Nigerian experience. *J. Environ. Pollut. Hum. Health* **2013**, *1*, 6–8.
18. Abu, R.; Patchigolla, K.; Simms, N. A Review on Qualitative Assessment of Natural Gas Utilisation Options for Eliminating Routine Nigerian Gas Flaring. *Gases* **2023**, *3*, 1–24. [CrossRef]
19. Schick, L. Mapping Gas Flares in the Niger Delta. Code of Africa (Impact Africa). 2017. Available online: https://medium.com/code-for-africa/mapping-gas-flares-in-the-niger-delta-f8963f327593 (accessed on 6 July 2022).
20. Mondal, S.K.; Uddin, M.R.; Majumder, S.; Pokhrel, J. HYSYS Simulation of Chemical Process Equipments. *Chem. Eng. Process.* **2015**, 1–7. [CrossRef]
21. Mokhatab Mak, J.Y.; Mokhatab, S.; Valappil, J.V. *Handbook of Liquefied Natural Gas*; Elsevier: Amsterdam, The Netherlands, 2014.
22. Helgestad, D.E. Modelling and optimization of the C3MR process for liquefaction of natural gas. In *Specialization Project, TKP 4550 Process Systems Engineering*; Norges Teknisk Naturviten Skapelige University (NTNU): Stavanger, Norway, 2009; 44p. Available online: https://folk.ntnu.no/skoge/diplom/prosjekt09/helgestad/Helgestad_project.pdf (accessed on 18 August 2022).
23. Fragkou, E. LNG Production Technologies and Process Simulation. Master's Thesis, School of Mineral Resources Engineering, Technical University of Crete, Chania, Greece, 2019. [CrossRef]
24. Chou, V.H.; Haslback, J.L.; Kyle, A.; Lewis, E.; Pinkerton, L.L.; Shah, V.; Varghese, E.; Woods, M.C. *Cost and Performance Baseline for Fossil Energy Plants-Volume 3c: Natural Gas Combined Cycle at Elevation (No. DOE/NETL-2010/1396)*; National Energy Technology Laboratory (NETL): Pittsburgh, PA, USA; Morgantown, WV, USA; Albany, OR, USA, 2011.
25. Arthur, T. *Control Structure Design for Methanol Process*; Norwegian University of Science and Technology: Trondheim, Norway, 2010.
26. Arthur, T. Simulation, optimal operation, and self-optimising control of methanol process. In *Specialization Project TKP 4555*; Norges Teknisk Naturviten Skapelige University (NTNU): Stavanger, Norway, 2012.

27. Fogler, H.S.; Fogler, S.H. *Elements of Chemical Reaction Engineering*; Pearson Educacion: London, UK, 1999.
28. EPA. *Greenhouse Gases Equivalencies Calculator-Calculator and References*; Energy and Environment, U.S. Environmental Protection Agency: Washington, DC, USA, 2021.
29. Nigeria Gas Flare Commercialization Programme (NGFCP). The Flare Gas (Prevention of Waste and Pollution) Regulations. 2018. Available online: https://ngfcp.dpr.gov.ng/resources/regulations/ngfcp-regulations/ (accessed on 10 September 2022).
30. The World Bank. *State and Trends of Carbon Pricing 2021*; World Bank: Washington, DC, USA, 2021; ISBN 978-1-4648-1728-1. Available online: http://hdl.handle.net/10986/35620 (accessed on 20 August 2022).
31. Peters, M.S.; Timmerhaus, K.D.; West, R.E. *Plant Design and Economics for Chemical Engineers*; McGraw-Hill Companies: New York, NY, USA, 2003.
32. U.S. Energy Information Administration (EIA). Engineering Economic Analysis Guide: Liquid Fuels Technologies, Independent Statistics and Analysis. 2015. Available online: https://www.eia.gov/outlooks/documentation/workshops/pdf/EEAGuide_1132016.pdf (accessed on 15 August 2022).
33. General Electric (GE). GE Power Gas Turbine. General Electric. 2021. Available online: https://www.ge.com/power/gas/gas-turbines/9ha (accessed on 7 July 2022).
34. Mitsubishi Heavy Industries Group. Mitsubishi Power Gas Turbine. Mitsubishi Power Ltd. 2021. Available online: https://power.mhi.com/products/gasturbines/lineup/h100 (accessed on 5 March 2022).
35. Tractebel Engineering. Mini and Micro LNG for Commercialization of Small Volumes of Associated Gas. World Bank, 2015. Available online: https://openknowledge.worldbank.org/bitstream/handle/10986/25919/112131.pdf?sequence=4&isAllowed=y (accessed on 21 August 2022).
36. Lim, O.S. Optimization of Gas Transmission Design. 2011. Available online: http://utpedia.utp.edu.my/id/eprint/10565/1/2011%20-%20Optimizing%20of%20gas%20transmission%20design.pdf (accessed on 20 August 2022).
37. South Asia Regional Initiative/Energy's (SARI/E). Natural Gas Value Chain: Pipeline Transportation. Global Energy Markets Trade Programme. 2015. Available online: https://docplayer.net/7351060-Natural-gas-value-chain-pipeline-transportation.html (accessed on 23 July 2022).
38. Alonso, F.; Greenwell, C. Underground vs. overhead: Power line installation-cost comparison and mitigation. *Electr. Light Power* **2013**. Available online: https://www.power-grid.com/td/underground-vs-overhead-power-line-installation-cost-comparison/#gref (accessed on 20 August 2022).
39. Nieradzinska, K.; MacIver, C.; Gill, S.; Agnew, G.A.; Anaya-Lara, O.; Bell, K.R.W. Optioneering analysis for connecting Dogger Bank offshore wind farms to the GB electricity network. *Renew. Energy* **2016**, *91*, 120–129. [CrossRef]