THERMO-ENVIRONMENTAL PERFORMANCE EVALUATION OF A RETROFIT INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) POWER PLANT

WRITTEN BY:

NOWAMAGBE AISOSA	**ENG2002477**
OTADAFEARIYO KINGSLEY	**ENG2002511**
GBENOBA JEREMIAH	**ENG2002453**

SUPERVISED BY:

PROF. OSAROBO IGHODARO
UNIVERSITY OF BENIN

SUBMITTED TO:

THE DEPARTMENT OF MECHANICAL ENGINEERING

IN FULFILLMENT OF THE REQUIREMENT FOR BACHELOR OF ENGINEERING (B.ENG) (MECHANICAL ENGINEERING)

OCTOBER 2025

CERTIFICATION

This is to certify that this project, Thermo-environmental performance evaluation of a retrofit integrated gasification combined cycle (IGCC) power plant, was carried out by NOWAMAGBE AISOSA (ENG2002477), OTADAFEARIYO KINGSLEY (ENG2002511), GBENOBA JEREMIAH (ENG2002453), in the department of Mechanical Engineering, Faculty of Engineering, University of Benin.

Prof. Osarobo Ighodaro **(Project Supervisor)**	**Date**
Engr. Martins Osikhueme **(Project Coordinator)**	**Date**
Prof. Osarobo Ighodaro **(Head of Department)**	**Date**

DEDICATION

The research work is dedicated to Almighty God who made it a success.

ACKNOWLEDGEMENT

First and foremost, we want to give thanks to God Almighty for the strength and wisdom to carry out this project.

Our heartfelt gratitude goes to our wonderful and highly esteemed supervisor, Prof. Osarobo Ighodaro, for his guidance, contributions, time, unceasing ideas, and disciplinary actions, which inspired us to put more effort and ensure this project was a success. He is the reason this project is possible.

We thank the staff at Afam VI Integrated combined cycle power plant, Afam, River state, for helping us with valuable data that made this project possible.

We also extend our profound gratitude to our parents and relatives, whose love and support saw us through this school.

ABSTRACT

Nigeria's energy security is heavily reliant on natural gas, a strategy hampered by supply unpredictability and growing global decarbonisation requirements. To address frequent outages caused by gas supply constraints and CO_2 emissions of 350-400 kg/MWh, a strategic pivot is necessary. This study proposes a transformative approach to addressing these dual challenges by retrofitting the Afam VI Natural Gas Combined Cycle (NGCC) power plant into an innovative Integrated Gasification Combined Cycle (IGCC) system. The study looks into the techno-environmental feasibility of repurposing existing infrastructure to use domestic coal and biomass blends, hence increasing fuel flexibility and lowering the plant's carbon footprint.

This work applies a rigorous simulation-based technique using EBSILON® Professional. A validated baseline model of the present Afam VI plant, which operates at 49.88% efficiency at base load, was created. This model was later updated to incorporate a gasification unit, air separation unit, syngas clean-up techniques and pre-combustion carbon capture. Necessary modifications were also made to the topping and bottoming cycle of the thermal block for syngas combustion.

Thermal analysis was carried out to assess system performance under both design and off-design scenarios. The results shows that the IGCC retrofit model reduces the net plant emission of the natural gas baseline model from about 300kg/MWh to about 50kg/MWh, indicating an 85.7% reduction in CO2 emission with a potential for carbon neutrality using biomass as feedstock. However, this comes off on the back of a trade off with the thermal performance of the plant. The retrofit model was found to have an energy efficiency penalty of about 4% points with respect to the natural gas baseline.

This results suggests that retrofit IGCC technology is not only technically feasible, but also strategically important for decarbonising the energy industry. It offers a practical, data-driven strategy for using indigenous energy resources to create a more resilient, sustainable, and secure power system. By presenting a feasible model for deep decarbonisation of existing infrastructure, this effort combines national development aspirations with global climate action, establishing IGCC as a baseline for future flexible and clean power generation.

Table of Contents

TABLE OF FIGURES

LIST OF TABLES

NOMENCLATURE

Ex	Exergy rate [MW]
E	Specific exergy [kJ/kg]
Ex_D	Exergy destruction rate [MW]
h	Enthalpy [kJ/kg]
ṁ	Mass flow rate [kg /s]
P	Pressure [Bar]
Q	Rate of heat flow [MW]
S	Specific entropy [kJ/kgk]
T	Temperature [°C]
W_{net}	Network done [MW]
Cond	Condenser
ή	Efficiency
$ή_{cyc}$	Cycle Efficiency
γ_c , γ_t	Specific heat capacities ratio
r_{pc}	Compressor Pressure ratio
r_{pt}	Turbine Pressure ratio
$ή_c$	Compressor isentropic efficiency
Cp_a	Specific heat capacity of air at constant pressure
$ή_{mech}$	Mechanical Efficiency
$ή_{Gen}$	Generator Efficiency

SUBSCRIPTS

a air

e exit

f fuel

I lnlet

w water

s steam

i inlet

in input

out output

ABBREVIATION

AC Air Compressor

CC Combustion Chamber

CCPP Combined Cycle Power Plant

IGCC Integrated Gasification Combined Cycle

NGCC Natural gas combined cycle

PFCC Post firing combined cycle

EFCC Externally fired combined cycle

GT Gas Turbine

HRSG Heat Recovery Steam Generator

HP High Pressure

LP Low Pressure

TIT Turbine inlet temperature

LHV	Lower Heating Value
TBCs	Thermal barrier coatings
CCS	Carbon capture and storage
ST	Steam Turbine
LCV	Low calorific value
ASUs	Air separation units
APH	Air preheater
FWP	Feed Water Pump
FWST	Feed Water Storage Tank
SCR	Selective Catalytic Reduction
CO	Carbon Monoxide
GHG	Greenhouse gas
MW	MegaWatt
HMI	Human Machine Interface
ACC	Air Cooled Condenser
CEP	Condensate Extraction Pump
HPFWP	High Pressure Feed Water Pump
LPFWP	Low Pressure Feed Water Pump
LPHRSG	Low Pressure Heat Recovery Steam Generator
HPHRSG	High Pressure Heat Recovery Steam Generator
LPST	Low Pressure Steam Turbine
HPST	High Pressure Steam Turbine
SFC	Specific Fuel Consumption

SSC	Specific Steam Consumption
WR	Work Ratio
HR	Heat Rate

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF STUDY

The global pursuit of energy security has become one of the defining challenges of the 21st century. As industrialization, population growth, and urban development continue to surge, the world's demand for energy intensifies. According to the International Energy Agency (IEA), global energy demand is projected to increase steadily over the next decades, driven largely by emerging economies striving for industrial advancement (Olhoff et al., 2024). However, this rapid increase in energy demand and consumption has come at a cost. The planet is warming at an alarming rate, with the United Nations (UN) reporting an average temperature rise of about 1.5°C above pre-industrial levels (State of global climate report, 2024). The effects of these changes are already manifesting in the form of extreme weather conditions, declining air quality and damage to ecosystems.

International agreements such as the Kyoto Protocol (1997) and the Paris Agreement (2015) have established global frameworks for decarbonising and lowering greenhouse gas (GHG) emissions in the energy sector, encouraging a worldwide shift toward low-carbon technologies. However, despite growing investments in renewable technologies, fossil fuels, especially coal and natural gas, currently account for over 60% of global electricity generation (IEA). This reliance persists due to their established infrastructure, relatively low cost, and energy density, especially in developing nations where energy access remains a socioeconomic priority.

In Nigeria, the situation presents a unique paradox. The country possesses one of Africa's largest proven natural gas reserves and substantial coal and biomass resources, yet electricity generation remains inadequate and unreliable. The majority of Nigeria's thermal power stations rely heavily on natural gas as the primary fuel. Although natural gas burns cleaner than coal or diesel, it contributes significantly to greenhouse gas (GHG) emissions. The IEA reports that the concentration of CO_2 in the environment reached an all-time high in 2024, with a concentration of 422.5ppm in 2024, indicating a 50% increase above pre-industrial levels. Also, with dependence on natural gas, Nigeria's energy sector faces increasing vulnerability due to pipeline vandalism, gas flaring policies, and unstable supply.

To address these challenges, the Nigerian government introduced the National Energy Policy (2003) and later the Renewable Energy Master Plan (2005), advocating diversification of the energy mix to include renewables like biomass. However, full-scale adoption remains limited due to technological and financial barriers. While coal and biomass exist as alternative energy sources, direct combustion of these solid fuels in conventional combustors produces high emissions of CO_2, SO_X, NO_X, and particulate matter, worsening Nigeria's environmental footprint. Thus, the nation finds itself trapped between energy insecurity and environmental degradation, both of which threaten its path toward sustainable industrial growth.

There is therefore a pressing need for a transitional technology, one that can make efficient use of Nigeria's abundant carbonaceous resources (coal, biomass, and natural gas) while minimizing its carbon footprint on the environment.

One promising option is the Integrated Gasification Combined Cycle (IGCC) system. IGCC converts carbon-based fuels into a cleaner synthesis gas (syngas) through gasification, a thermochemical process that breaks down carbonaceous feedstock such as coal, biomass, municipal waste, petroleum waste etc. into CO, H_2, and CH_4. The resulting syngas is purified and combusted in a combined cycle configuration to generate electricity with higher efficiency and lower emissions compared to conventional plants (Shadle & Breault, 2012). Importantly, IGCC systems enable seamless integration of carbon capture and storage (CCS), and they can co-fire coal and biomass, offering both fuel flexibility and environmental advantages (Park et al., 2014; Li et al., 2014).

Although IGCC plants are capital-intensive, retrofitting existing Natural Gas Combined Cycle (NGCC) stations provides a feasible alternative for countries like Nigeria. Such retrofits involve integrating gasification units and syngas-compatible components into existing systems, avoiding the cost of constructing new plants. Studies by Siemens and GE have indicated that these modifications can significantly reduce emissions while maintaining combined-cycle efficiency (Gutierrez et al., 2006a; Reiss & Reyser, 2002).

In light of these considerations, the present study examines the performance and carbon footprint implications of retrofitting the Afam VI Power Plant with Integrated Gasification Combined Cycle (IGCC) technology. Employing a simulation-based thermodynamic approach in off-design mode, the research models the retrofitted plant configuration and evaluates its operational performance and environmental impact relative to the existing natural gas combined-cycle (NGCC) system. This analysis provides a foundation for assessing the technical feasibility and sustainability potential of IGCC integration within Nigeria's thermal power infrastructure.

1.2 PROBLEM STATEMENT

Nigeria's power sector is predominantly dependent on natural gas, with over 80% of its electricity generation capacity tied to gas-fired plants (Udo, 2015). While natural gas offers cleaner combustion compared to coal, this heavy reliance has created a structural vulnerability. Supply disruptions due to infrastructure failures, pipeline vandalism, or upstream production issues frequently result in nationwide blackouts (Adenikinju, 2008). Beyond the domestic challenges, the global push to decarbonize energy systems, as emphasized in international agreements such as the Kyoto Protocol (1997) and Paris Agreement (2015), calls for the diversification of fuel sources and adoption of cleaner, more flexible power generation technologies.

Integrated Gasification Combined Cycle (IGCC) technology offers a viable pathway to address both reliability and sustainability challenges. By gasifying coal, biomass, or blended feedstocks to produce a clean syngas for combined cycle operation, IGCC enables fuel flexibility, high thermal efficiency, and reduced emissions, particularly when integrated with pre-combustion carbon capture (Park et al., 2014). Despite these advantages, IGCC deployment in developing economies remains minimal due to high capital costs, technical complexity, and the lack of locally relevant performance studies (Consonni & Larson, 1996; Kanniche & Bouallou, 2010).

This study addresses these gaps by performing a simulation-based performance and carbon footprint assessment of retrofitting a Combined Cycle power plant with IGCC capability. Various fuel scenarios will be evaluated, natural gas and syngas derived from coal, biomass and various blends to determine the operational, environmental, and retrofit feasibility of such a transition under off-design operating conditions.

1.3 AIM OF STUDY

This study aims to carry out a comparative evaluation of the thermo-environmental performance of retrofitting the Afam VI Thermal Power Plant with Integrated Gasification Combined Cycle (IGCC) technology.

1.4 OBJECTIVES

The objectives of this project include the following:

1 To develop a baseline simulation model of the existing Afam VI Thermal Power Plant configuration using *EBSILON Professional v13.0.*
2 To validate the model against available operational data.
3 To simulate the retrofit integration of IGCC technology into a dual-fired combined cycle configuration, incorporating gas turbine modifications necessary for syngas combustion.
4 To assess the effect of varying syngas composition on plant thermal efficiency and emissions.
5 To conduct detailed energy analysis for the baseline and retrofitted IGCC configurations, identifying key sources of inefficiency.
6 To compare the techno-environmental performance of the retrofitted IGCC system against the existing NGCC baseline, focusing on efficiency gains, emissions reduction, and operational feasibility

1.5 SCOPE OF STUDY

This research is limited to the modelling, simulation, and thermodynamic evaluation of a retrofitted Integrated Gasification Combined Cycle (IGCC) configuration using EBSILON Professional v13.0 as the primary simulation tool. The scope covers the following areas:

1. Thermodynamic Analysis: Comprehensive evaluation of energy and exergy flows, identification of irreversibilities, and determination of system efficiencies based on the First and Second Laws of Thermodynamics.

2. Heat and Mass Transfer: Investigation of heat exchange mechanisms within gasification units, heat recovery steam generators (HRSGs), and other combined cycle components, including integration with steam and syngas cooling systems.
3. Power Plant Engineering: Examination of advanced thermal power plant configurations, focusing on combined cycle systems, gasification processes, and syngas utilization in retrofitted gas turbines.
4. Computer-Aided Engineering: Use of EBSILON Professional v13.0 for steady-state simulation and performance modeling of both the baseline Natural Gas Combined Cycle (NGCC) configuration and the retrofitted IGCC system.

1.6 SIGNIFICANCE OF STUDY

The proposed study holds both technical and environmental relevance in addressing growing energy demand while aligning with global decarbonization goals.

This study will:

1. Provide a simulation-based performance benchmark for integrating IGCC technology into an existing Natural Gas Combined Cycle (NGCC) plant, enabling stakeholders to predict operational outcomes prior to physical implementation.
2. Demonstrate the thermodynamic implications of fuel switching and co-firing with syngas, supporting informed decisions on optimal fuel blends for both efficiency and emissions reduction.
3. Contribute to the limited body of research on off-design performance simulations for IGCC retrofits, ensuring realistic performance assessment under real-world operating conditions.
4. Offer evidence-based insights for policymakers and plant operators on adopting cleaner energy technologies in line with the Paris Agreement targets.
5. Support Nigeria’s energy diversification goals by illustrating the viability of syngas from biomass and coal–biomass blends as supplementary fuels.

CHAPTER TWO

LITERATURE REVIEW

This chapter reviews existing literature relevant to Integrated Gasification Combined Cycle (IGCC) systems, with emphasis on their application for retrofitting existing Natural Gas Combined Cycle (NGCC) plants. The review covers key aspects of IGCC technology, gas turbine modifications for syngas combustion and simulation of gas turbines. It also examines comparative studies of the performance and environmental impact of natural gas, syngas and pulverized coal fired plants.

Furthermore, the chapter evaluates the thermodynamic performance of IGCC systems through energy and exergy analyses, highlighting research findings on system efficiencies, irreversibilities and carbon reduction potential. Literature on off-design performance assessments is also considered to underline the importance of realistic simulation in retrofit feasibility studies. In addition, the review incorporates studies on cost-effective retrofit configurations such as external firing, co-firing, and post-firing and their operational implications.

2.1 COMPARATIVE ASSESSMENT OF NATURAL GAS COMBINED CYCLE (NGCC), PULVERISED-COAL (PC), AND INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) POWER SYSTEMS

The rapid evolution of thermal power generation technologies has driven a continual search for systems that balance high efficiency with minimal environmental impact. Among the dominant configurations, Natural Gas Combined Cycle (NGCC), Pulverised-Coal (PC), and Integrated Gasification Combined Cycle (IGCC) power plants represent distinct technological pathways for converting fossil and renewable feedstocks into electricity. Each system presents unique thermodynamic characteristics and environmental trade-offs shaped by its fuel source, process integration, and emission-control strategies as established across a broad range of studies (Li et al., 2014; Franco & Giuffrida, 2014; Kapetaki, 2015; NETL, 2012; Mallick et al., 2018).

The NGCC configuration remains the global benchmark for fuel-to-power conversion efficiency. Its combined Brayton–Rankine cycle arrangement enables thermal efficiencies typically between 40% and 65 % depending on the design and operating conditions of the plant (NETL, 2012; Li et al., 2014). Abdulsitar, in an analysis, performed a thorough examination of a 1500MW NGCC power plant. Exergy and energy studies carried out revealed the combustion chamber as the major source of exergy destruction. The operating exergy and energy efficiency were observed to be 43.7% and 46.1% respectively (Abdulsitar et al., 2025).

By contrast, conventional pulverised-coal plants, even in supercritical or ultra-supercritical form, achieve net efficiencies of only 33–38 %, constrained by the inherent chemical-to-thermal conversion losses and large exergy destruction within the boiler (Franco & Giuffrida, 2014; NETL, 2012).

The IGCC system occupies an intermediate position, coupling gasification and cleanup with a combined cycle bottoming section. Typical demonstration IGCC plants report net efficiencies of 40–50 % without carbon capture, dropping by 4–8 percentage points when pre-combustion CO_2 capture is introduced (Li et al., 2014; Park et al., 2014). Kapetaki (2015) demonstrated through process modelling that proper heat integration between the gasifier, air-separation unit (ASU), and CO_2 solvent regeneration loop can recover much of this penalty, producing exergetic efficiencies near 45 % typically approaching NGCC performance. However, other studies have revealed that the extent of integration, gasifier type, and feedstock composition (bituminous versus lignite or biomass fraction) significantly influence the achievable efficiency of IGCC plants, allowing IGCC to achieve efficiencies within the range of NGCC plants(Gutierrez et al., 2006b).

In environmental terms, NGCC plants exhibit specific CO_2 emissions typically 350–400 kg CO_2/MWh, depending on the carbon intensity of the natural-gas supply (NETL, 2012). PC plants, even with modern flue-gas desulphurisation and particulate controls, emit 900–1,000 g CO_2/MWh along with notable SO_x and NO_x emissions. IGCC systems occupy a transitional role: without CO_2 capture they emit 600–900 kg CO_2/MWh, but with integrated pre-combustion capture their emissions can be reduced by 85–90 %, often outperforming NGCC in net carbon intensity (Li et al., 2014; Park et al., 2014). Moreover, because sulphur and particulates are removed prior to combustion, IGCC stack emissions of SO_x, particulates, and trace metals are markedly lower than in PC systems (Knoope et al., 2015; NETL, 2012).

Biomass and coal-biomass co-gasification further enhance IGCC's environmental profile. Mallick et al. (2018) demonstrated that blending 10–30 % biomass (energy basis) yields synergistic effects resulting in lower CO_2 intensity and improved gas syngas without severe penalties in efficiency. Similarly, Long (Long, 2015) reported that a 10 % biomass fraction could render an IGCC system effectively carbon-neutral, provided appropriate pretreatment (e.g., torrefaction or pelletization) mitigates handling and fouling challenges.

Across the literature, consensus emerges that NGCC offers superior energy efficiency and operational flexibility, making it ideal for short-term deployment and part-load operation. However, its decarbonisation potential is limited without post-combustion capture, which imposes substantial efficiency penalties. Pulverised coal remains the least favourable option thermodynamically and environmentally, despite maturity and low fuel cost. The Coal/Biomass IGCC concept, though capital-intensive, provides the most balanced pathway for deep carbon reduction when integrated with pre-combustion CO_2 capture. Studies employing process simulation tools such as *EBSILON Professional*, *Aspen Plus*, and *MATLAB–Simulink* consistently highlight IGCC's flexibility and scalability, particularly for retrofitting existing combined-cycle plants (Kapetaki, 2015; Li et al., 2014; Park et al., 2014).

2.2 IGCC TECHNOLOGY OVERVIEW

The Integrated Gasification Combined Cycle (IGCC) is an advanced power generation technology designed to convert carbonaceous fuels such as coal, biomass, or petroleum residues into clean synthesis gas (syngas) for high-efficiency electricity generation. The system integrates gasification and a combined cycle configuration, allowing simultaneous improvements in thermal efficiency and emissions reduction compared to conventional pulverized coal and natural gas fired power plants (Shadle et al., 2012; Park et al., 2014). Over the last two decades, extensive research and demonstration projects have validated IGCC's technical viability for fuels such as coal, biomass, petroleum coke, municipal solid waste, and refinery residues (Higman & van der Burgt, 2011). Researches have also shown that depending on feedstock type, plant size, and process configuration, modern IGCC plants can achieve net efficiencies of 40–55% (Park et al., 2014), while enabling pre-combustion carbon capture with reduced energy penalties.

The core of IGCC is the gasification process, in which the feedstock undergoes partial oxidation under oxygen- and steam-rich conditions. This thermochemical conversion occurs at high temperatures (1200 – 1600 °C) and pressures (20 – 40 bar), producing synthesis gas (syngas) primarily composed of carbon monoxide (CO) and hydrogen (H_2), with smaller fractions of methane (CH_4), carbon dioxide (CO_2), water vapor (H_2O), and trace contaminants (Higman et. al., 2011). The synthesis gas(syngas) then serves as fuel for the downstream combined cycle.

The raw syngas leaving the gasifier contains impurities such as particulate matter, tar, sulfur compounds (mainly H_2S and COS), and trace metals. It is then passed through gas clean-up and conditioning systems, which include cyclones or filters for solids removal, scrubbers for particulate and chloride control, and chemical absorption systems (e.g., Selexol, Rectisol, or amine-based) for desulfurization and CO_2 capture. This pre-combustion cleaning stage is one of the defining advantages of IGCC, since pollutants are removed before combustion, enabling ultra-low emissions of SO_x, NO_x, and particulates.

The cleaned syngas is then directed to the combined cycle power block, consisting of a gas turbine, heat recovery steam generator (HRSG), and steam turbine. In the gas turbine, syngas is combusted with compressed air to drive the turbine and generate power. The hot exhaust gases from the turbine enter the HRSG, where their residual heat produces high-pressure steam that drives a secondary steam turbine, maximizing the energy recovery. This dual use of thermal energy yields overall efficiencies between 42–50%, significantly higher than conventional coal-fired plants.

An additional advantage of IGCC systems is their inherent compatibility with carbon capture and storage (CCS). Because CO_2 can be separated from syngas before combustion (a pre-combustion capture approach), IGCC plants can achieve capture efficiencies exceeding 85–90% with relatively minor efficiency penalties compared to post-combustion systems.

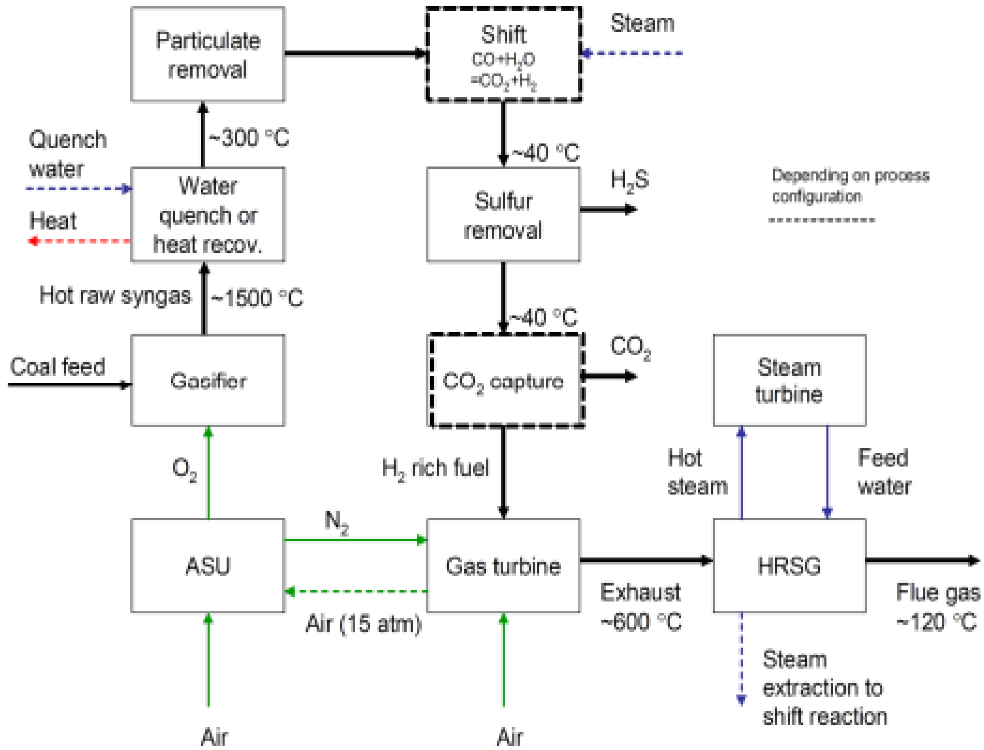


Figure 1. Typical IGCC Process Flow (Maurstad, 2005)

Also, the modular process blocks of IGCC systems allow for flexibility in design and retrofit applications, making it a promising pathway for decarbonizing existing combined cycle power plants.

2.3 EFFECT OF SYNGAS COMBUSTION ON GAS TURBINE OPERATION

The introduction of syngas as a fuel in gas turbines significantly alters the thermodynamic and operational environment compared to conventional natural gas firing. Syngas, produced from coal or biomass gasification possesses a low heating value (LHV) typically ranging from 5 to 15 MJ/kg(Cocco et al., 2013; NETL, 2012), which is substantially lower than the 45–50 MJ/kg of natural gas(Eke et al., 2018). Consequently, turbines originally designed for natural gas operation face challenges related to fuel flow rate, combustion dynamics, and component durability when retrofitted for syngas operation. Recent advances by leading manufacturers, including Siemens and General Electric, have enabled the development of turbines capable of operating on low-calorific fuels such as syngas, notably the SGT5-2000E, SGT6-5000F, and GE 9001 EC series (Smith, 2009).

Jurado et al. (2003) examined the thermodynamic performance of combined-cycle systems using biomass-derived syngas and observed that 2–4 times higher fuel mass flow is required to achieve the same power output as natural gas due to syngas's lower LHV. The increased mass flow leads to elevated flow rates through the turbine expansion stages, shifting the compressor operating point closer to the surge line, thereby reducing the engine's turndown capability. Similarly, (Oluyede & Phillips, 2007)reported that the volumetric flow rate of typical syngas compositions can exceed that of natural gas by approximately 14%, potentially increasing net power output by 20–25% at a constant turbine inlet temperature (TIT). However, this apparent gain is offset by higher exhaust moisture content (due to hydrogen combustion) and increased thermal loading on turbine blades, which elevate the risk of overheating and material fatigue.

Padture et. al (2002) highlighted that turbine components originally designed for natural gas may not withstand the higher moisture and temperature gradients associated with syngas combustion. They recommended the adoption of advanced thermal barrier coatings (TBCs) and enhanced internal cooling geometries to preserve component lifespans under such conditions. These findings underscore the importance of including heat transfer and material stress models in extensive simulation studies.

The combustion behavior of syngas differs markedly from natural gas due to its variable composition and the high reactivity of hydrogen. Chacartegui et al. (2011) demonstrated that fluctuations in syngas composition strongly influence flame speed, stability limits, and dynamic response, demanding robust control systems for stable operation. Lieuwen et al. (2008) found that hydrogen-rich syngas exhibits laminar flame speeds three to eight times faster than methane, increasing the risk of flashback where the flame propagates upstream into the fuel nozzles in premixed combustors. This risk necessitates combustor and fuel nozzle redesign, often involving diffusion-based or staged-combustion approaches.

Huang et. al (Huang et. al ,2009) in their study, showed that syngas's high flame speed and changed flame structure drastically alter the flame transfer function, increasing the likelihood that combustors may experience thermoacoustic oscillations that could result in mechanical damage. Furthermore, because of its fundamentally different flame reaction, mitigation measures that work for natural gas instabilities, such as Helmholtz dampers and particular fuel staging patterns, need to be significantly modified or redesigned for stable syngas operation (Lieuwen et al. , 2008).

Biomass-specific materials difficulties were noted by Liu et al. (2011). Their study discovered that alkali metals (potassium, sodium) that are volatilised during biomass gasification can deposit on hot gas route components. This can cause protective oxide scales to be destroyed, which can increase hot corrosion (sulfidation or oxidation), particularly if sulphur is present. Knoope et al. (2015) also stated that erosive damage to turbine blades and nozzles might result from gas clean up systems' inability to completely remove particles (ash, char), especially in high-velocity areas.

The influence of biomass syngas fuel composition on combustion performance and emissions in a micro gas turbine combustor was examined by Liu et al. (2011). Their study aimed to quantify stability limits under various H2/CO ratios and diluent levels. According to their findings, although a high hydrogen concentration theoretically raises the lean blowout (LBO) limit, in practice, using highly diluted syngas, which is frequently used in IGCC for temperature control, can result in local extinction occurrences because hydrogen's high diffusivity causes mixture stratification.

2.3.1 MODIFICATIONS TO GAS TURBINE COMPONENTS FOR SYNGAS COMBUSTION

Retrofitting existing NGCC to IGCC will involve the redesign of several components of the existing natural gas turbine. However, this comes with a considerable investment cost. An increase in efficiency is achieved with an increase in the rate of IGCC integration into existing NGCC. A balance of level of integration/complexity, performance and cost must, however, be achieved.

In an extensive review by Smith (Smith, 2009), he suggested modifications needed for natural gas turbines to combust syngas. According to his study, existing natural gas turbines can be adapted for syngas, but this requires significant changes in the combustor design, fuel system, compressor and turbine cooling strategy to preserve performance and reliability. These changes are due to syngas's distinct properties of high hydrogen content, wide flammability range, and increased moisture and contaminant levels.

COMPRESSOR MODIFICATIONS

Firing gas turbines with syngas results in a significantly increased mass flow rate of fuel due to its low volumetric heating value, typically requiring up to seven times the volumetric flow of natural gas to maintain comparable turbine inlet temperatures (Oluyede & Phillips, 2007). This demand places a greater load on the compressor, necessitating mechanical upgrades to manage the increased flow and pressure.

One critical risk arising from this increased flow rate requirement is compressor surge, a phenomenon that occurs when the compressor operates outside its stable operating range, particularly at high pressure ratios and altered flow conditions. Surge can result in flow reversal, severe vibration, and even mechanical damage.

The Alstom GT13E2 turbine, for instance, addresses this by integrating an additional 22nd compressor stage, derived from its 21st stage but with a reduced blade span, thereby increasing the overall pressure ratio and accommodating the syngas flow requirements (Alstom, 2009). Chiesa et. al. (2005) emphasized that compressor maps must be re-evaluated during IGCC retrofit studies to ensure surge margin is maintained, especially when operating with pre-diluted syngas or during part-load operations.

Maintaining a sufficient surge margin becomes even more important with syngas, as minor changes in ambient conditions or composition variability can induce instability. Hence, retrofitted IGCC designs often include dynamic control systems that monitor surge proximity and adjust operating parameters in real-time to avoid unsafe compressor behavior.

EXPANDER NOZZLE MODIFICATION

Another proposed method to handle the increased turbine flow associated with syngas combustion is modifying the expander nozzle. Since syngas combustion results in lower temperature but higher mass flow of combustion gases, the existing turbine nozzle may become a bottleneck. A wider expander nozzle or altered vane geometry allows the turbine to handle increased flow rates without inducing excessive backpressure or overheating the rotor blades.

Lee et al. (2013) demonstrated that increasing throat areas in nozzle guide vanes helped manage the rise in flow while keeping the exit Mach number and blade loading within design limits. Though this approach requires some structural changes, it is considerably less capital-intensive than a full hot-section redesign.

COMBUSTOR REDESIGN AND DILUTION

Syngas's higher flame speed and autoignition tendency necessitate a shift from conventional combustor geometries. Dilution using inert gases such as nitrogen or steam is commonly employed to lower the flame temperature and delay ignition. Alstom's implementation shows that 55% N_2 dilution by volume can halve the flame speed and shift the ignition zone downstream, enabling low-NOx combustion (Alstom, 2009).

Additionally, Oluyede (2007) emphasizes that the high hydrogen content in syngas leads to elevated water vapor formation during combustion, significantly increasing the heat load on turbine hot gas path components. To compensate, turbine OEMs recommend lower firing temperatures to maintain hot-gas path integrity.

TURBINE SECTION AND COOLING ADJUSTMENTS

A major impact of syngas combustion is the rise in mass flow rate through the turbine due to the low calorific value and high exhaust gas volume. This increase can enhance power output by up to 25% compared to natural gas, but it also imposes higher thermal and mechanical stress on turbine blades and vanes (Oluyede & Phillips, 2007).

Materials-wise, turbine hot-gas components originally designed for natural gas may suffice, but may suffer reduced durability in syngas environments. Sulfur, particulates, and elevated water vapor levels accelerate coating degradation. Improved thermal barrier coatings and erosion-resistant materials become essential for long term operation.

As noted by Chiesa et. al. (2005), increased moisture from H_2-rich syngas combustion further augments convective heat transfer to turbine surfaces, thereby necessitating these advanced cooling strategies. To accommodate this, OEMs such as GE and Siemens often recommend advanced cooling techniques, such as Improved air film cooling designs, enhanced thermal barrier coatings (TBCs) and use of advanced turbine materials with higher creep resistance.

2.3.2 OFF-DESIGN OPERATIONAL MODIFICATIONS FOR SYNGAS COMBUSTION IN GAS TURBINES

Modification of gas turbine components for syngas combustion is capital intensive. The low heating value (LHV), higher mass flow, and increased moisture content of syngas demand substantial design changes to combustors, compressors, and turbine sections. However, several studies have proposed lower-cost alternatives to make existing natural gas turbines adaptable to syngas, thereby reducing retrofitting expenses while ensuring operational safety and performance. These methods, broadly considered as off-design operation strategies, include gas turbine de-rating, expander nozzle modifications and compressor bleed for surge margin control.

TURBINE DE-RATING

According to (Oluyede & Phillips, 2007), firing syngas may increase the turbine flow by up to 14% compared to natural gas, potentially enhancing power output by 20–25% under ideal conditions. Yet, mechanical limitations such as turbine blade temperature limits, Mach number restrictions, and compressor surge margins often cap this potential.

One of the simplest and most economical solutions for adapting natural gas turbines to syngas combustion is de-rating which is operating the turbine below its nominal power capacity. Syngas, due to its LHV, requires significantly higher volumetric flow rates to maintain the same power output. However, many existing gas turbines have hardware limits on volumetric flow capacity, which can be exceeded when switching to syngas. De-rating allows for continued operation without violating surge limits or causing overheating of turbine parts.

COMPRESSOR BLEED FOR SURGE MARGIN

Maintaining adequate surge margin in syngas operations is critical, especially when compressor inlet conditions are altered by the high volume flow of syngas. One cost-effective approach is to use compressor bleed, which involves deliberately bleeding off some of the airflow from later compressor stages. This reduces the risk of surge, especially at part-load operation, and helps preserve compressor stability.

The higher mass flow requirement of syngas tends to push compressors toward surge limits. Compressor bleed acts as a safeguard mechanism, ensuring the stability is preserved while delaying or avoiding the need for major compressor redesign (Oluyede & Phillips, 2007)

2.4 DESIGN CYCLE CONFIGURATIONS FOR IGCC RETROFITTING

The capital cost of modifying existing gas turbine systems for full syngas combustion remains prohibitively high, particularly when a complete redesign of the combustion chambers, nozzles, and control systems is required. Consequently, several alternative IGCC system configurations have been proposed and studied for retrofitting purposes. These include external firing, co-firing, and post-firing arrangements, each offering varying degrees of system performance improvements and capital intensity.

CO-FIRING CONFIGURATION

Co-firing involves the simultaneous combustion of syngas and a conventional fuel, typically natural gas in separate combustion chambers. This method provides a practical route to reducing the cost and complexity of full syngas conversion by leveraging existing infrastructure. One of its most attractive benefits is the mitigation of operational limitations associated with low calorific value (LCV) fuels.

In the co-firing configuration, air from the compressor is preheated and then combusted with natural gas in the gas turbine combustion chamber. The hot gases, after running the gas turbine, is then used for combusting syngas in a post combustion chamber unit. The ensuing combustion gases is then used for air preheating and steam generation.

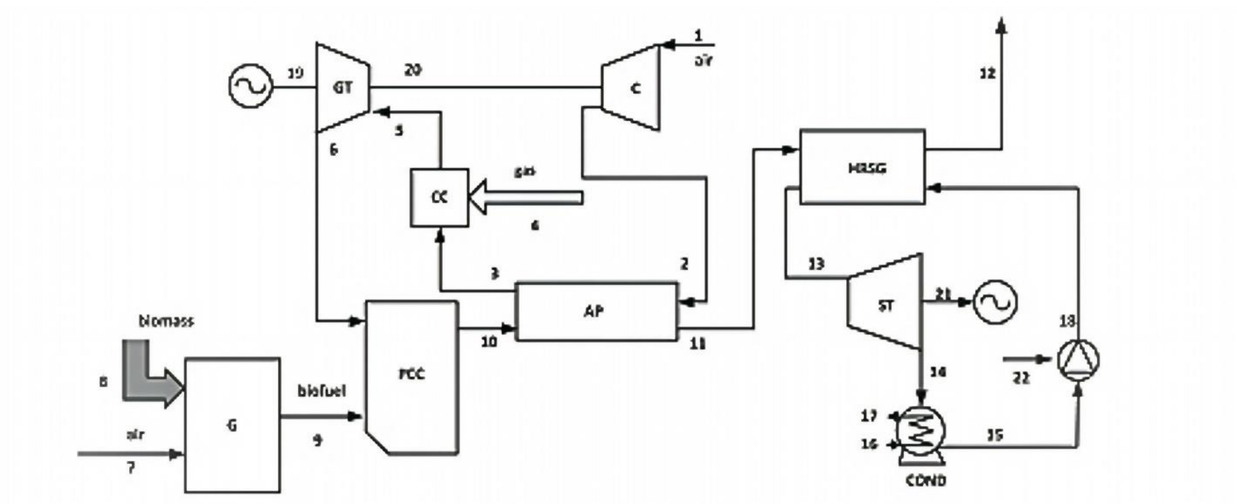


Figure 2. Co-firing IGCC configuration, (Soltani et al., 2014b)

POST-FIRING CONFIGURATION

Post-firing combined cycles (PFCC) involve the combustion of syngas downstream of the primary combustion chamber, typically in the heat recovery steam generator (HRSG) or a post-combustion unit. This approach reduces the stress on the gas turbine combustor by isolating syngas combustion from the main turbine flow path.

Soltani et al. indicate that post-firing yields higher energy efficiency (by 3–6 percentage points) compared to externally fired or co-firing configurations. The combustion gases from the gas turbine, which still contain residual oxygen, support the oxidation of syngas in a post-combustion chamber before entering the HRSG, boosting steam production without directly affecting gas turbine operation (Soltani et al., 2014)

This method proves especially attractive for repowering existing simple cycle plants, offering thermal integration with minimal disturbance to the original gas turbine layout. Post-firing requires moderate investment for a secondary combustor and control system but avoids complex turbine modifications.

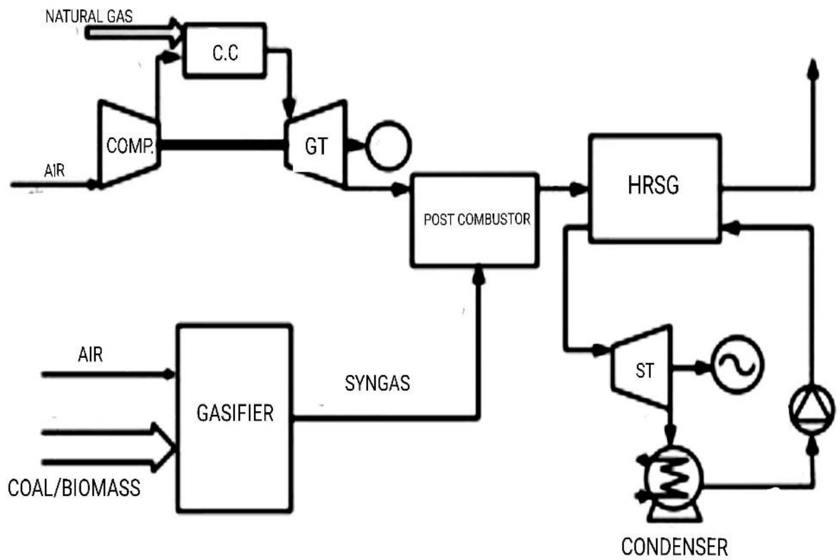


Figure 3. Post-firing IGCC configuration, (Soltani et al., 2014)

EXTERNALLY FIRED CONFIGURATION

The externally fired combined cycle (EFCC) configuration offers another retrofitting strategy wherein syngas is combusted in a separate chamber, and the hot flue gases are used to indirectly heat the working fluid via a heat exchanger or recuperator. The hot flue gases are then used to generate steam in the HRSG of the bottoming cycle (Soltani et al., 2014). This configuration completely decouples syngas combustion from the gas turbine, removing concerns related to LCV fuel stability or hydrogen content in the turbine combustor.

However, the EFCC's main limitation lies in the thermal losses associated with heat exchangers and the resulting lower cycle efficiency. According to Soltani et al. while EFCCs avoid the need for extensive gas cleaning (as no syngas enters the turbine), they also yield the lowest energy efficiency of the three considered configurations (Soltani et al., 2014)

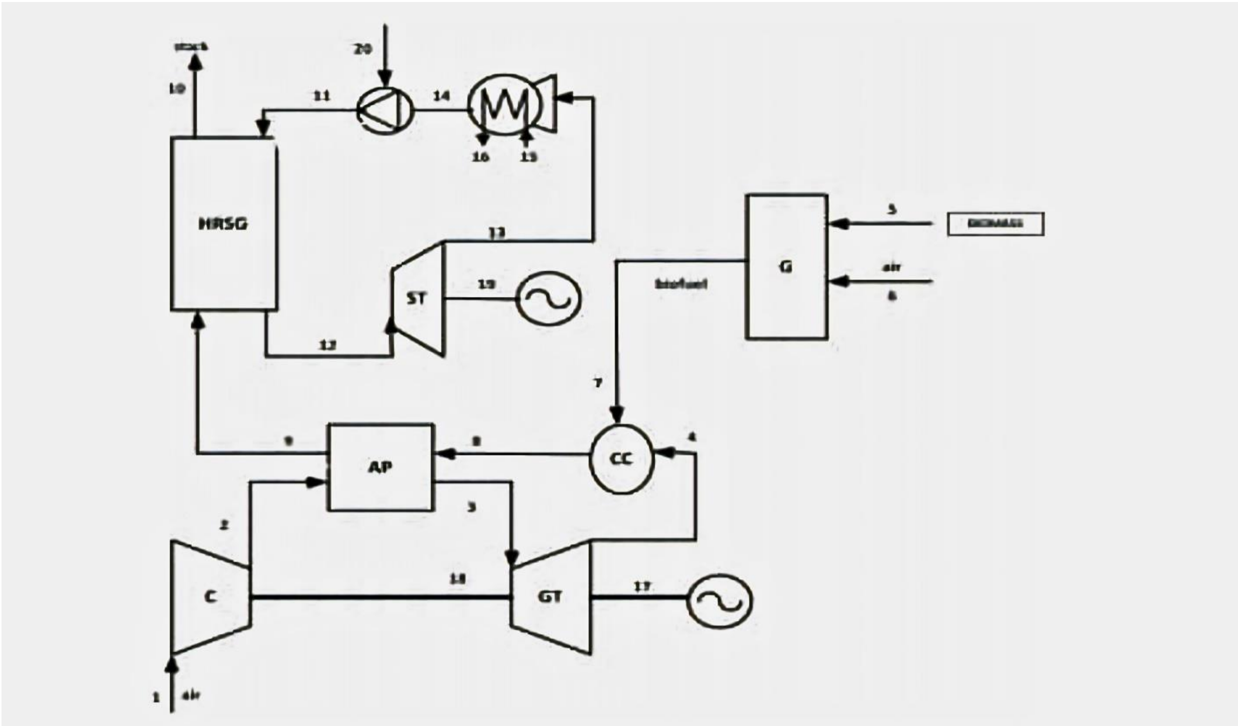


Figure 4. Externally firing IGCC configuration (Soltani et al., 2014)

Each option presents a trade-off between capital investment, efficiency, and system complexity. Co-firing stands out as the most practical solution, particularly for plants with access to both biomass and natural gas. Post-firing offers higher efficiencies but with moderate capital needs, while external firing remains a niche option with the lowest integration risks but reduced thermodynamic performance.

2.5 OFF-DESIGN PERFORMANCE ANALYSIS AND ITS RELEVANCE TO IGCC RETROFITTING

Off-design performance analysis is essential for evaluating the operational flexibility and reliability of power plants under varying load conditions, ambient temperatures, and fuel compositions. These parameters rarely remain constant in real-world settings. For retrofitting existing power plants, especially when transitioning from natural gas combined cycle (NGCC) systems to Integrated Gasification Combined Cycle (IGCC) configurations, simulating off-design performance becomes crucial.

IGCC systems are inherently complex due to the integration of modular blocks of gasification units, air separation units (ASUs), syngas cleanup, and the combined cycle. These subsystems interact dynamically, making their performance sensitive to changes in load and ambient conditions. As noted by Valero et al. (2006), a complete exergy-based off-design model helps capture component-level inefficiencies and allows the operator to identify potential bottlenecks under transient operation. Similarly, Assadi and Breuhaus (2005) employed an off-design simulation framework for advanced IGCC systems and emphasized its role in quantifying part-load efficiency losses and increased auxiliary power consumption.

Several studies have suggested methods to enhance the accuracy of off-design modeling. Zheng and Furman (2003) adopted an off-design thermodynamic model for IGCC power plants that incorporated real gas turbine performance maps, variable compressor pressure ratios, and ambient-adjusted turbine inlet temperatures. They concluded that the control strategy (e.g., inlet guide vane modulation or TIT control) significantly influenced the performance deviation from design conditions, with efficiency drops exceeding 5% at part-load operation.

In retrofitting scenarios, such as converting an NGCC plant to co-fire biomass or syngas, off-design performance simulations are critical for evaluating the feasibility of using alternative fuels with different calorific values and combustion properties. As highlighted by De Franco et al. (2017), retrofitted systems are more prone to mismatches in turbine mass flow rates and pressures, necessitating recalibration or partial redesign of critical components like nozzles and compressors.

Therefore, comprehensive off-design analysis enables optimal component resizing, improves control strategies, and ensures a realistic assessment of performance metrics post-retrofit. Without such evaluations, retrofitted IGCC systems may suffer from lower-than-expected efficiencies, reliability issues, or unanticipated mechanical stress.

2.6 MODELLING AND SIMULATION IN IGCC RETROFIT STUDIES

Simulation and modelling have become indispensable tools in the study and design of thermodynamic systems, particularly for retrofit and optimization applications. The high complexity and capital cost of IGCC systems make full-scale experimental evaluation impractical, while the growing need for cleaner, more flexible power systems demand detailed assessment before implementation. Through process simulation, researchers can replicate the thermodynamic, chemical, and environmental behaviour of integrated power systems under a wide range of operating conditions, including off-design and transient modes (Kapetaki, 2015; Li, Yan, & Anheden, 2014).

Retrofitting an existing Natural Gas Combined Cycle (NGCC) plant to an IGCC configuration involves introducing new subsystems such as a gasifier, syngas conditioning units, and CO_2 capture trains into an already optimized plant architecture (Gutierrez et al., 2006b). This integration modifies mass and energy flows throughout the plant, often leading to significant changes in turbine behaviour, HRSG loading, and auxiliary power consumption (Oluyede & Phillips, 2007a). Conducting such an evaluation experimentally would be economically and logistically infeasible. Simulation, therefore, provides a risk-free environment, enabling engineers to analyze and optimize the retrofitted plant before capital deployment.

A major strength of simulation lies in its ability to capture off-design and part-load performance, which determines the reliability and flexibility of power plants in real grid conditions.

Franco and Giuffrida (2014) conducted exergy and energy simulations of IGCC plants with pre-combustion CO_2 capture using *Aspen Plus*, observing that process optimization through simulation could recover nearly 3 percentage points in net efficiency compared to non-integrated designs. Likewise, Calise et al. (2012) demonstrated via *Cycle-Tempo* simulation that proper integration of waste-heat recovery and gasification sections could raise overall exergy efficiency by 4–6%, illustrating how simulation-guided design refinement translates into real thermodynamic gains.

Accuracy remains central to simulation credibility. According to the U.S. Department of Energy (NETL, 2012), properly calibrated IGCC models reproduce overall plant efficiencies and CO_2 capture rates with less than 2% deviation from test-bench data when appropriate gasifier correlations and solvent property packages are used. Kapetaki (2015) reported that process simulations of Shell and GE-type IGCC configurations using Honeywell UniSim R400 and BR&E ProMax matched NETL benchmark performance achieving agreement within ±3% for net efficiency and ±2% for specific CO_2 emissions. Similarly, Li et al. (2014) applied Aspen Plus to simulate different CO_2 capture schemes in IGCC and found their model predictions deviated by only 1.5% from pilot-plant data, confirming the robustness of model-based studies for capture integration.

These results establish that with appropriate property methods and validated reaction models, modern simulators can replicate plant thermodynamics and component interactions to a high degree of accuracy, making them sufficiently reliable for feasibility and optimization studies.

Beyond accuracy, simulation offers a strategic framework for evaluating the technical, economic, and environmental feasibility of retrofit projects. Studies such as Li et al. (2014) and Kapetaki (2015) demonstrate how parametric variation of gasifier temperature, oxygen-to-fuel ratio, or CO_2 capture pressure can reveal optimal trade-offs between efficiency, emissions, and capital cost.

2.7 COMPARATIVE REVIEW OF SIMULATION TOOLS FOR IGCC AND COMBINED-CYCLE MODELLING

Accurate modelling is crucial for assessing the thermodynamic and environmental performance of Integrated Gasification Combined Cycle (IGCC) systems, particularly when evaluating retrofit or off-design scenarios. The choice of simulation platform significantly affects the fidelity of the results, influencing the representation of reaction kinetics, system integration, and component behaviour (Li et al., 2014; Kapetaki, 2015).

Several commercial software packages exist for thermodynamic simulation, ranging from Ebsilon Professional, Aspen Hysys, Honeywell Unisim, Thermoflex, Gatecycle etc.

Aspen Plus is one of the most widely employed software in IGCC research for detailed process-level simulation. It uses equilibrium and kinetic models to describe gasification, water–gas shift, and CO_2 capture processes with rigorous chemical accuracy. Kapetaki (2015) employed Aspen Plus to model an IGCC system with post-combustion CO_2 capture, achieving close values, within ±2 %, with benchmark data from NETL reports. Similarly, Li et al. (2014) used Aspen Plus to compare Selexol and Rectisol solvents for CO_2 capture and found good predictive reliability across varying process configurations. It lacks robust modules for off-design or dynamic plant behaviour, limiting its application for retrofits where variable load and turbine performance must be evaluated.

In contrast, EBSILON Professional is an energy-system simulator developed specifically for thermodynamic cycle and off-design analysis. It uses component-based mass- and energy-balance equations coupled with empirical performance maps, allowing a realistic representation of part-load turbine and heat-recovery behaviour (Franco & Giuffrida, 2014). Studies report that calibrated EBSILON models can predict combined-cycle and IGCC efficiencies within 1–2 % of operational data (Franco & Giuffrida, 2014). While less detailed in chemical kinetics, EBSILON excels in retrofit feasibility and system integration studies, where emphasis lies on power, efficiency, and parasitic load evaluation rather than reaction chemistry.

Similarly, recent validation work by Szega et al. (2024) using EBSILON v16 for a waste-gasification and combined-heat-and-power system found agreement within **2–3 %** when compared to Aspen Plus models for syngas composition and energy flow (Energies, 17(23), 6034). These findings demonstrate that EBSILON delivers high predictive reliability across a range of feedstocks and process configurations.

Other platforms such as GateCycle and Thermoflex are effective for conventional combined-cycle design but lack flexibility for multi-fuel or gasification-based integration (Park et al., 2014). Meanwhile, MATLAB/Simulink and Modelica environments have been adopted for dynamic control modelling and start-up/shutdown analyses (Kang et al., 2012), though they require coupling with thermodynamic simulators for complete plant evaluation.

2.8 SUMMARY AND RESEARCH GAP

Extensive research has examined Integrated Gasification Combined Cycle (IGCC) systems and their integration with carbon capture technologies. However, most of these studies address new-build IGCC plants. There is limited research on retrofitting existing Natural Gas Combined Cycle (NGCC) systems into coal- or biomass-based IGCC configurations. Reports mention feasibility of combustor redesign, ASU integration, and syngas conditioning (Gutierrez et al., 2006), yet comprehensive off-design or part-load simulations of such retrofits are scarce.

Comparative analyses indicate that IGCC systems generally achieve higher exergy efficiencies (45–50%) and lower CO_2 emissions than pulverized-coal plants (about 35–38%) (Franco & Giuffrida, 2014; Harinck et al., 2014). Still, these advantages are offset by higher capital costs and system complexity. Recent studies also confirm that validated thermodynamic simulations for example, those performed in EBSILON Professional, with deviations typically within ±3% of plant data (Kapetaki, 2015; Szega et al., 2024), are vital for reliable performance prediction and retrofit assessment.

In summary, while IGCC technology has been extensively analyzed for efficiency and emission control, its retrofit application to NGCC systems remains underexplored. This gap justifies the present EBSILON-based investigation into the thermodynamic and environmental performance of converting the Afam VI power plant to a coal/biomass IGCC configuration.

CHAPTER THREE

METHODOLOGY

This research adopts a simulation-based design methodology to evaluate the performance and environmental impact of retrofitting an NGCC, Afam VI Combined Cycle Power Plant (CCPP), into an Integrated Gasification Combined Cycle (IGCC) configuration. The design integrates process modelling, thermodynamic analysis, and performance comparison using EBSILON® Professional v13.0.

The approach involves developing a model of the Afam VI plant as the base configuration and then extending the model to include a gasification island, air separation unit (ASU), and syngas cleanup system for simulating IGCC operation. The model operates under steady-state conditions and replicates both design and off-design modes for comparative evaluation.

Performance evaluation to determine overall thermal efficiency, exergy destruction across major components, and CO_2 emission rates per unit of power generated are then conducted. The simulation results are validated using operational and design data from the Afam VI power plant and benchmarked with literature data from comparable IGCC systems.

3.1 BASELINE POWER PLANT CONFIGURATION AND DESCRIPTION

The Afam VI Power Plant, located in Rivers State, Nigeria, is a combined cycle power plant with an installed capacity of approximately 650 MW. The plant consists of three GT13E2 gas turbine units, each with an OEM rated capacity of 150 MW, and one dual-pressure ST10 steam turbine with a rated capacity of 200 MW. The system is configured in a 3 × 1 format, providing a capacity of 650 MW at 50Hz synchronous frequency. The gas turbines are fired exclusively with natural gas supplied from the nearby Okoloma Gas Plant.

The GT13E2 gas turbine, manufactured by Alstom, is a heavy-duty, single-shaft industrial turbine designed for high efficiency and operational flexibility in combined-cycle applications. It operates at a synchronous frequency of 50 Hz and a rotational speed of 3,000 rpm, featuring a 17-stage axial compressor with variable inlet guide vanes for effective airflow control and enhanced part-load efficiency. The turbine operates with combustion occurring in sequential annular combustors that provide stable combustion and low NO_x emissions. Expansion in the turbine occurs through four turbine stages.

The plant operates on the Brayton–Rankine combined cycle principle, in which the exhaust heat from the gas turbines is recovered in the Heat Recovery Steam Generator (HRSG) to produce steam for the steam turbine. Air is drawn into the compressor at inlet state (1) through an air filtration system that removes harmful solid particles from the incoming air stream. This air is then compressed by the compressor to a higher temperature and pressure at state (2). The compressed air is fed into the combustion chamber, where it mixes with natural gas from the fuel supply system and undergoes combustion to produce high-temperature gases.

The hot combustion gases exit the combustion chamber and enter the gas turbine (GT) at state (3). These gases expand through the turbine stages to a lower pressure and temperature at state (4). The expansion process rotates the turbine rotors, providing the mechanical energy required to drive the generator and produce electricity.

The flue gases at state (4) then passes on to the Heat Recovery Steam Generator (HRSG), where high- and low-pressure feedwater streams are heated to produce vapor. The flue gas exits the high-pressure HRSG at state (5), the low-pressure HRSG at state (6), and finally the exhaust stack at state (7) after undergoing heat exchange within the HRSG system.

Superheated steam is generated from both the high-pressure and low-pressure sections of the HRSG, at states (10) and (8) respectively. The high-pressure steam expands in the High-Pressure Steam Turbine (HPST) to state (9), after which it mixes with the low-pressure superheated steam from the Low-Pressure HRSG (LPHRSG) at state (10), forming a homogeneous steam mixture at state (11). This combined steam stream then expands in the Low-Pressure Steam Turbine (LPST) to state (12). The mechanical energy produced by the steam turbine is converted into electrical power through a coupled electric generator.

The exhaust steam leaving the LPST at state (12) is condensed in the steam condenser into saturated liquid water at state (13). The condensate is then pumped by the Condensate Extraction Pump (CEP) through the pre-heater line at state (14). From state (15), the feedwater flow divides, part is directed to the Low-Pressure HRSG via the Low-Pressure Feedwater Pump (LP-FWP) at state (16), while the remainder is pressurized by the High-Pressure Feedwater Pump (HP-FWP) to state (17) and fed into the High-Pressure HRSG to complete the thermodynamic cycle.

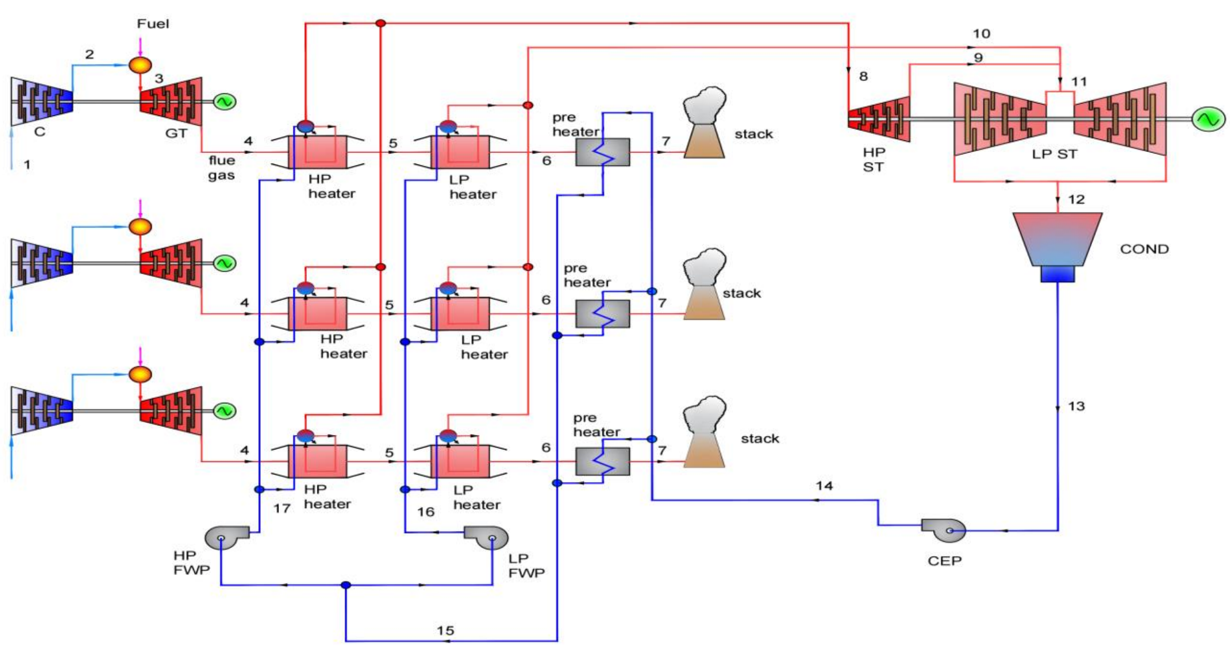


Figure 5. SCHEMATIC OF AFAM VI COMBINED CYCLE POWER PLANT

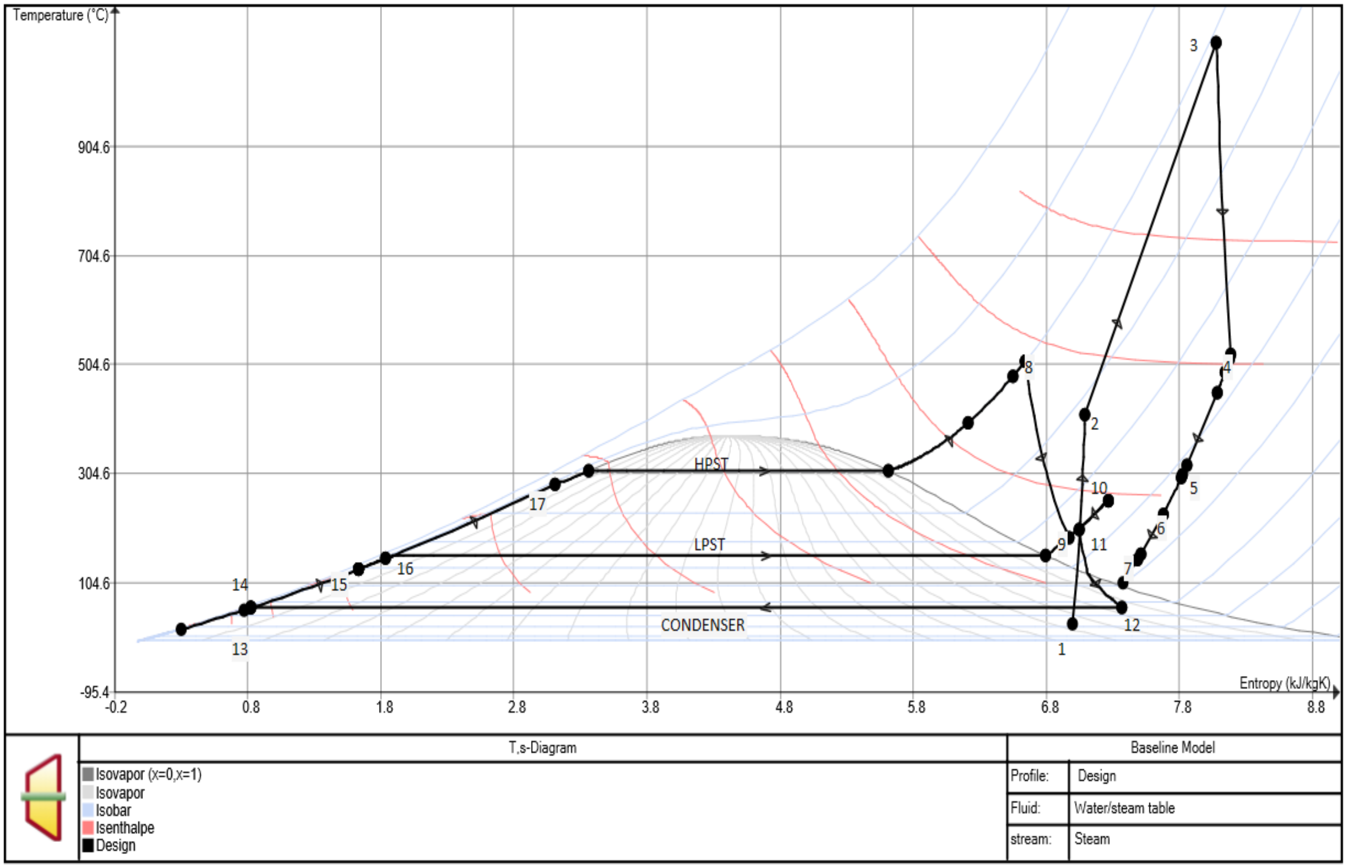


Figure 6. T-S diagram of the Baseline Combined Cycle Power Plant (CCPP)

3.2 DESCRIPTION OF RETROFITTED IGCC POWER PLANT MODEL

The retrofitted Integrated Gasification Combined Cycle (IGCC) model was developed from the existing Afam VI Combined Cycle Power Plant by introducing a gasification island and associated auxiliary systems upstream of the gas turbines. The retrofit model also involves specific modifications to both the topping and bottoming cycles of the CCPP. However, the core combined-cycle configuration of Afam VI, comprising three GT13E2 gas turbines, dual-pressure HRSGs, and one ST10 steam turbine, is preserved so that the retrofitted design maintains the proven Brayton–Rankine integration while gaining fuel flexibility and improved environmental performance.

The fuel-handling system is reconfigured to include three principal subsystems: an Air Separation Unit (ASU), a Gasification Unit, and a Gas Cleaning and Conditioning Section. The ASU produces high-purity oxygen required for partial oxidation in the gasifier and also provides a nitrogen stream that can be used for syngas dilution or combustion control. In the gasifier, coal and/or biomass react with oxygen and steam at elevated temperatures and pressures to form a raw syngas stream primarily composed of CO and H_2, along with smaller amounts of CO_2, H_2O, and trace impurities.

The hot raw syngas is routed through a syngas cooler, where heat recovery generates high-pressure steam that supplements HRSG steam production.

After leaving the cooler, the syngas passes through the Gas Cleaning and Conditioning Section, which removes particulates, sulphur, tars, and other contaminants using cyclones, filters, and acid-gas removal (AGR) solvents. The cleaned syngas is then conditioned for combustion, it may be reheated, slightly enriched, or blended to achieve the desired temperature and composition required for stable combustion in the gas turbine.

Within the thermal block of the plant, the cycle configuration of the combined cycle is modified into a dual-fuel or co-fired CCPP arrangement. The retrofitted layout incorporates a Post-Combustion Chamber (PCC) for syngas combustion in the topping cycle, installed immediately downstream of the gas turbine. This dual-combustion arrangement compensates for the lower calorific value of syngas and mitigates its detrimental effects on gas turbines originally designed for natural gas firing. The PCC ensures that the turbine inlet temperature (TIT) is maintained at the optimal design level, thereby preserving turbine performance, material integrity, and overall power output.

An Air Preheater (APH) is also introduced downstream of the compressor to raise the temperature of the compressed air before it enters the combustion chamber. Preheating the air reduces the amount of natural gas required in the combustor to reach the desired TIT. This modification reduces specific fuel consumption, and improves the overall thermal efficiency of the cycle.

The flue gases exiting the air preheater then proceed to the Heat Recovery Steam Generator (HRSG), where the remaining thermal energy is recovered to generate high- and low-pressure steam for the bottoming Rankine cycle.

In the bottoming cycle, integration of the steam generated in the syngas cooler with the low-pressure steam from the HRSG is implemented to improve energy utilization. Effluent steam from the syngas coolers are directed to the low-pressure superheater to enhance the quality of steam entering the steam turbine. To achieve this, a throttle valve and mixer are incorporated into the model to control and homogenize the steam streams. This configuration is modelled in EBSILON to capture its positive effect on overall steam generation, plant efficiency, and combined-cycle performance.

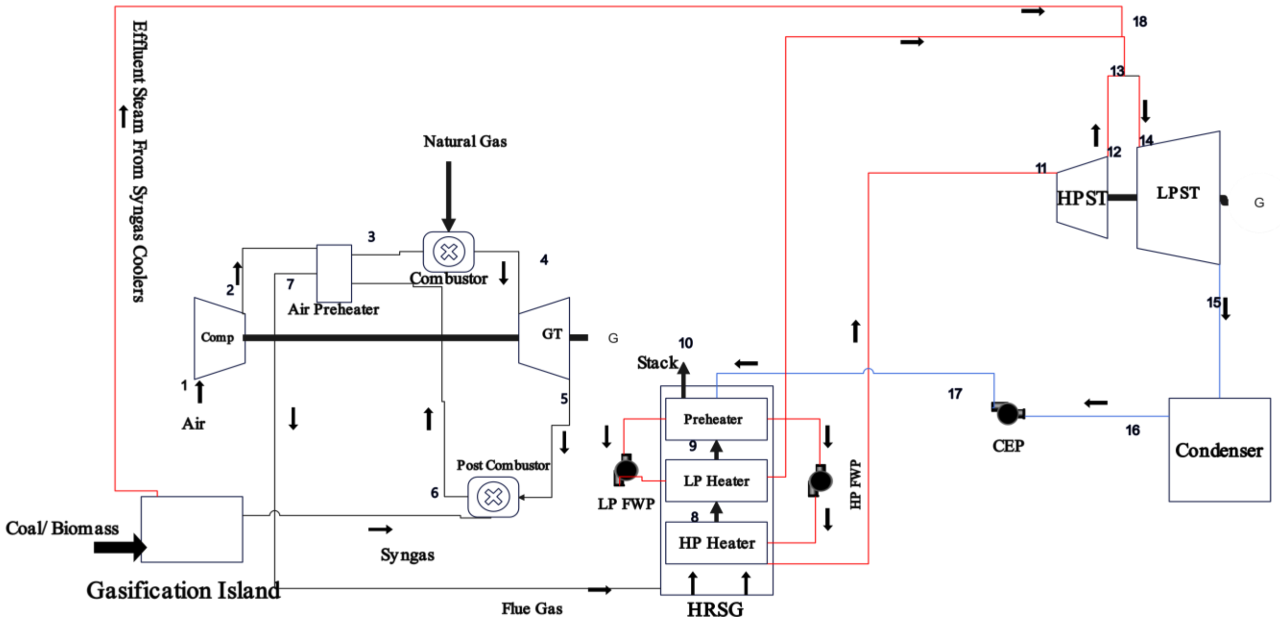


Figure 7 Schematic Diagram of IGCC Retrofitted CCPP

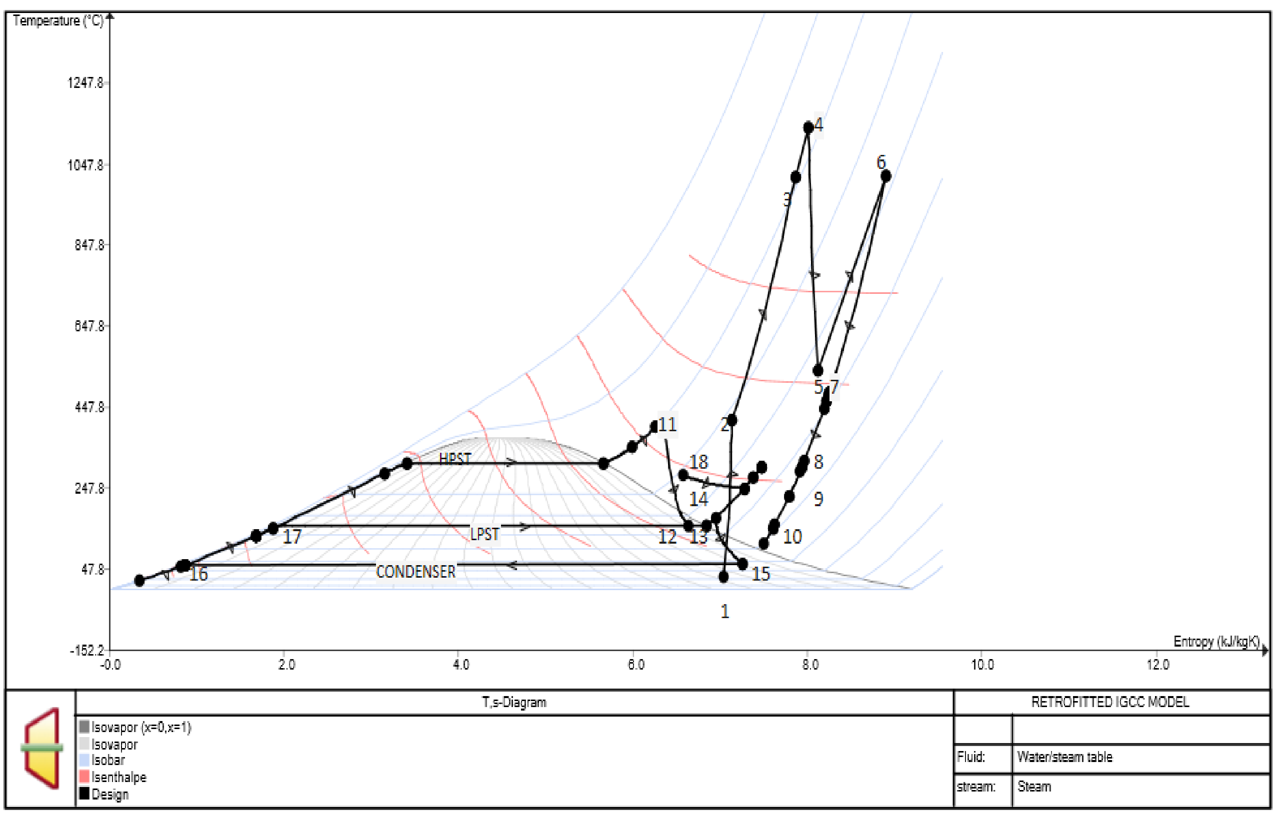


Figure 8 T-S diagram of retrofitted IGCC model

3.3 SIMULATION ENVIRONMENT AND MODEL SETUP

The simulation of both the base and retrofitted IGCC configurations was carried out using EBSILON® Professional v13.0, a thermal simulation software designed for steady-state thermodynamic analysis of power plants. EBSILON employs component-oriented modelling to represent complex energy systems by combining thermodynamic components and defining the interconnections between them through material, energy, and information streams. This environment allows for flexible system configuration, performance analysis under varying conditions, and the evaluation of modifications such as gasification integration and dual-fuel operation.

In this study, the simulation environment was used to develop related plant models with distinct topology:

1. The base Combined Cycle Power Plant (CCPP) representing the existing Afam VI configuration operating solely on natural gas.
2. The retrofitted IGCC model, which integrates the gasification island, air preheater, and post-combustion chamber while preserving the core combined-cycle framework.

The modelling approach begins with the component-based representation of the plant's thermodynamic layout. Major components such as compressors, combustors, turbines, heat exchangers, HRSGs, condensers, and pumps are selected from EBSILON's component library and interconnected according to the flow sequence established in the process diagrams. For the base plant, the model includes three GT13E2 gas turbines, three dual-pressure HRSGs, and a single ST10 steam turbine operating in a 3 × 1 configuration. Each gas turbine model includes the compressor, combustion chamber, and expansion turbine sections, connected through defined thermodynamic states representing pressure, temperature, and mass flow conditions.

For the retrofitted IGCC configuration, additional components are introduced into the model to represent the newly integrated systems. These include the gasifier, air separation unit (ASU), syngas cooler, gas cleaning and conditioning system, air preheater (APH), and the post-combustion chamber (PCC). The gasifier is modelled as a reactor component that converts coal and/or biomass feedstock into a syngas mixture with specified composition and lower heating value (LHV). The ASU is modelled as a compressor-expander block that separates atmospheric air into high-purity oxygen and nitrogen streams at defined pressures and flow rates. The syngas cooler and air preheater are modelled using heat exchanger components, where energy recovery and heat transfer effectiveness are specified to simulate realistic thermal interactions.

The Post-Combustion Chamber (PCC) is represented as a secondary combustor positioned between the gas cleaning section and the gas turbine inlet. It is parameterized to achieve the desired turbine inlet temperature (TIT) by adjusting the syngas and supplementary fuel flow rates. The air preheater, placed downstream of the compressor, raises the temperature of the compressed air before combustion, improving fuel utilization and thermal efficiency. The HRSG and steam turbine sections are configured identically to the base model but with added linkages that allow integration of low-pressure steam from the gasification island and syngas cooler. A throttle valve and mixer component are incorporated to regulate and homogenize the steam streams before entry into the steam turbine.

Boundary conditions such as ambient temperature, pressure, and humidity were defined based on the average site conditions at Afam VI. Material properties, component efficiencies, pressure losses, and heat transfer coefficients were specified based on manufacturer data, plant operational records, and literature values for comparable systems. The model was executed under steady-state conditions for each of the various fuel compositions.

Simulation results including mass and energy balances, component efficiencies, and emission indicators were validated against available operational data from the Afam VI plant and benchmark data from similar IGCC plants reported in literature. The validated model was then used to perform thermodynamic and environmental performance comparisons between the base and retrofitted configurations.

3.4 STEADY STATE MODELLING OF COMBINED CYCLE SETUP

The baseline and retrofitted model of the Afam VI NGCC power plant was developed using EBSILON Professional v13.0, which provides libraries of thermodynamic components for steady-state power plant simulations. The complete plant configuration, including the compressor, combustion chamber, gas turbine, heat recovery steam generator (HRSG), steam turbine, condenser, pumps, and auxiliary systems, was constructed by selecting appropriate component blocks from the EBSILON library and parameterizing them to match the characteristics of Afam VI.

The modelling approach relies on predefined component models in EBSILON. For each component, key parameters such as efficiency, pressure ratio, temperature limits, and flow conditions were specified. These values were primarily obtained from plant design specifications and available operating data for Afam VI, with supplementary data from published literature and manufacturer references used where direct plant data were unavailable. Although EBSILON solves the governing equations internally, the fundamental principles of mass and energy conservation, exergy analysis, and component performance laws (e.g., Stodola's ellipse law for turbines, ideal gas relations for compressors) guided the selection of parameters and the subsequent validation of the model.

The system was modelled as a network of control volumes connected by defined inlet and outlet streams, with each control volume obeying the general steady-flow energy equation.

Each major plant component compressors, combustors, turbines, HRSG, steam turbine, condenser, pumps, gasifier, and auxiliaries selected from the Ebsilon professional library was modelled with formulations shown below alongside with appropriate efficiencies and performance curves.

3.5.1 COMPRESSOR MODELLING

The air compressor draws in ambient air and compresses it to the high pressure required for efficient combustion in the combustor.

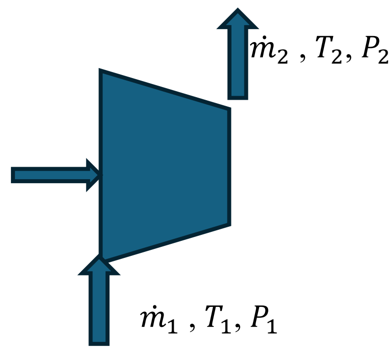
In EBSILON, the compressor was modelled using Component 94 (compressor with characteristic curve), which allows the input of performance maps that relate the corrected mass flow, pressure ratio, and efficiency as a function of rotational speed.

Governing Equations

At the design condition, the compressor can be modelled using fixed parameters derived from manufacturer specifications and validated with plant operating data.

Mass balance:

$$\dot{m}_{air} = \dot{m}_2 = \dot{m}_1 \quad (1)$$



Energy balance:

$$W_c = \dot{m}_{air} \cdot C_{p_{air}} \cdot (T_2 - T_1) \quad (2)$$

Isentropic efficiency:

$$\eta_c = \frac{T_{2s} - T_1}{T_2 - T_1} \quad (3)$$

Temperature–pressure relation (ideal gas):

$$r_p = \frac{P_2}{P_1} = \left(\frac{T_{2s}}{T_1}\right)^{\frac{\gamma}{\gamma - 1}} \quad (4)$$

In gas turbines, the power required for driving the compressor is provided by the gas turbine and transmitted through a shaft. Friction losses occurring in the shaft can be accounted for by mechanical efficiency η_m.

Thus, work done input in the compressor is represented by:

$$W_c = \frac{\dot{m}_{air} \cdot C_{p_{air}} \cdot (T_2 - T_1)}{\eta_m} \quad (5)$$

Where:

η_c= isentropic efficiency of the compressor,

P_1 and P_2 = suction and discharge pressure

r_p = compression ratio

T_1, T_2 , T_s= inlet, outlet and isentropic temperatures,

$\dot{m}_{air}$= air mass flow rate.

$C_{p_{air}}$= Specific heat capacity of air at constant pressure

3.5.2 COMBUSTION CHAMBER

The combustion chamber was modelled using component 22 from the Ebsilon professional component library. The combustor control volume assumes steady flow, negligible kinetic and potential energy terms, and adiabatic (or near-adiabatic) operation with an assigned combustion efficiency to account for incomplete conversion and heat losses.

The combustion process raises the temperature of the working fluid from the compressor discharge temperature $T_1$to the turbine inlet temperature T_2.

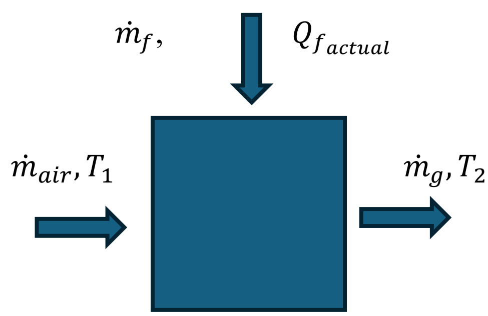


Figure 9. Fluid properties of the combustion area

$$\dot{m}_{air} + \dot{m}_f = \dot{m}_g \qquad (1)$$

Energy balance:

$$Q_{f_{actual}} = \dot{m}_g \cdot C_{pg} \cdot T_2 - \dot{m}_{air} \cdot C_{p_{air}} \cdot T_1 \qquad (2)$$

$$Q_{f_{theoretical}} = \dot{m}_f \cdot LHV$$

Combustion chamber efficiency:

$$\eta_{cc} = \frac{Q_{f_{actual}}}{Q_{f_{theoretical}}} \qquad (3)$$

Where:

$\dot{m}_{air}$, $\dot{m}_g$ *and* $\dot{m}_f$ = mass flow of air, combustion gases and fuel,

$Q_{f_{theoretical}}$ and $Q_{f_{actual}}$ = theoretical and actual heat supply by fuel

LHV = Lower heating value of fuel

T_1 and T_2 = compressor exit temperature and turbine inlet temperature (TIT) respectively

η_{cc} = combustion efficiency

3.5.3 GAS TURBINE MODEL

The gas turbine was modelled using Component 23 from the EBSILON® Professional v13.0 component library. The turbine is represented as a steady-flow adiabatic expansion device that converts the thermal energy of high-temperature combustion gases into mechanical work. Kinetic and potential energy effects are neglected, and an isentropic efficiency is assigned to account for irreversibilities in the expansion process.

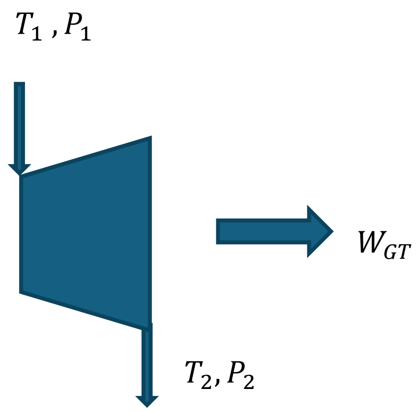


Figure 10. Steam turbine and gas turbine fluid properties

Mass balance:

$$\dot{m}_{g_{in}} = \dot{m}_{g_{out}} \tag{1}$$

Energy balance:

$$\text{W}_{GT} = \dot{m}_g \cdot C_p \cdot (T_2 - T_1) \tag{2}$$

Isentropic efficiency:

$$\eta_{s_{GT}} = \frac{T_1 - T_2}{T_1 - T_{2s}} \quad (3)$$

Gas turbine net power output:

$$W_{GT_{net}} = W_{GT} - W_c \quad (4)$$

Gas turbine thermal efficiency:

$$\eta_{GT} = \frac{W_{GT_{net}}}{\dot{m}_f \ x \ LHV} \cdot 100\% \quad (5)$$

Specific Fuel Consumption (SFC):

$$SFC = \frac{\dot{m}_f \ x \ 3600}{W_{GT_{net}}} \quad (6)$$

Where:

W_{GT} *and* W_{net} = GT gross and net power output respectively,

$\dot{m}_g$ = mass flow of combustion gases,

T_1 *and* T_2 = Turbine inlet and outlet temperatures respectively.

η_{GT} = GT thermal efficiency

To capture off-design behaviour, the turbine model uses performance maps (efficiency, corrected mass flow and pressure ratio versus corrected speed) as the primary correlation data. Maps are applied using corrected variables (mass flow and speed corrected to standard reference conditions) so that changes in ambient conditions and operating speed are reflected accurately in predicted mass flow, pressure ratio and efficiency.

Where maps are not available for every operating point, Stodola's correlation (the "law of the ellipse") is used as the engineering fallback to relate off-design mass flow, pressure ratio and speed.

3.5.4 HEAT RECOVERY STEAM GENERATOR (HRSG) MODEL

The Heat Recovery Steam Generator (HRSG) was modelled using Component 61 from the EBSILON® Professional v13.0 component library. The HRSG control volume assumes negligible kinetic and potential energy changes, with steady mass and energy balances across the heat-exchanger sections.

Each HRSG unit in the baseline plant is a dual-pressure HRSG consisting of economizer, evaporator, and superheater sections for both high- and low-pressure steam circuits. The overall heat transfer process in each section is represented by the steady-state energy balance.

Where:

$\dot{m}_g$= exhaust gas mass flow rate,

$\dot{m}_s$= steam/water mass flow rate,

c_{p_g}= specific heat of exhaust gases,

$T_{g,in}, T_{g,out}$= gas inlet and outlet temperatures,

$h_{s,in}, h_{s,out}$= specific enthalpies of feedwater and generated steam

3.5.5 STEAM TURBINE MODEL

The steam turbine was modeled using Component 6 from the EBSILON® Professional v13.0 component library. The turbine operates as a steady-flow adiabatic expansion device, converting the thermal energy of superheated steam into mechanical shaft power that drives the electric generator. Kinetic and potential energy changes are neglected, and losses due to irreversibilities are accounted for through an assigned isentropic efficiency (η_{st}).

Mass balance:

$$\dot{m}_{s_1} = \dot{m}_{s_2} \quad (1)$$

Energy balance:

$$W_{ST} = \dot{m}_s(h_1 - h_2) \quad (2)$$

Isentropic efficiency:

$$\eta_{ST} = \frac{h_1 - h_2}{h_1 - h_{2_s}} = \frac{T_1 - T_2}{T_1 - T_{2_s}} \quad (3)$$

Thermal efficiency of steam turbine is calculated as

$$\acute{\eta}_{ST} = \frac{W_{ST_{net}}}{Q_{HRSG}} \cdot 100\% \quad (4)$$

Total network done by the steam turbine is

$$W_{ST_{net}} = (W_{ST} - W_{FWP})$$

Thermal efficiency of steam turbine on is calculated as

$$\eta_{ST} = \frac{W_{ST_{net}}}{Q_{HRSG}} \text{ x } 100 \tag{5}$$

Specific steam consumption (SSC)

$$\text{SSC} = \frac{\dot{m}_{w} \text{ x } 3600}{W_{net,ST}} \tag{6}$$

Where:

W_{ST}= turbine power output (kW),

$\dot{m}_s$= steam mass flow rate (kg/s),

h_1, h_2 *and* $h_{2_{,s}}$= inlet, actual outlet, and isentropic outlet specific enthalpies (kJ/kg).

To represent off-design performance, the model uses manufacturer performance maps that relate corrected mass flow, pressure ratio, and efficiency to the corrected rotational speed. These maps allow EBSILON to interpolate turbine efficiency and flow parameters at varying load and ambient conditions.

Where complete map data are unavailable, Stodola's correlation (the *law of the ellipse*) is applied to approximate off-design mass flow as a function of inlet and outlet pressures and temperatures:

$$\left(\frac{m_i}{m_{iN}}\right)^2 = \frac{p_i}{p_{eN}} \cdot \frac{v_{iN}}{v_i} \cdot \frac{1-\left(\frac{p_e}{p_i}\right)^2}{1-\left(\frac{p_{eN}}{p_{iN}}\right)^2} \tag{7}$$

This relationship ensures that mass flow and power output vary consistently with pressure-ratio and temperature changes during part-load or variable-condition operation. EBSILON combines the performance-map interpolation and Stodola correlation to achieve accurate steady-state predictions of steam-turbine performance under both design and off-design conditions.

3.5.6 CONDENSER MODEL

The condenser was modelled using Component 33 from the EBSILON® Professional v13.0 component library. It functions as a steady-flow heat exchanger that condenses the exhaust steam from the steam turbine by transferring heat to a circulating cooling-water stream. The process operates at constant pressure (equal to condenser back-pressure), and the outlet condensate is assumed to be saturated liquid. Kinetic and potential energy effects are neglected.

Mass balance:

$$\dot{m}_{s,in} = \dot{m}_{cond,out} \tag{1}$$

Energy balance:

$$\dot{m}_s(h_{in} - h_{out}) = \dot{m}_{cw}\, c_{p,cw}(T_{cw,out} - T_{cw,in}) \quad (2)$$

Where:

$\dot{m}_s$= steam mass flow rate (kg/s),

h_{in}, h_{out}= specific enthalpies of steam at condenser inlet and outlet (kJ/kg),

$\dot{m}_{cw}$= cooling-water mass flow rate (kg/s),

$c_{p,cw}$= specific heat of cooling water (kJ/kg·K),

$T_{cw,in}, T_{cw,out}$= inlet and outlet cooling-water temperatures (°C).

The overall performance characteristic of the combined cycle

The overall combined cycle power output is calculated as

$$W_{CCPP} = W_{GT_{net}} + W_{ST_{net}} \quad (3)$$

The combined cycle thermal efficiency

In order to determine the performance of the CCPP, overall thermal efficiency must include the efficiency of the GT cycle and the ST cycle.

$$\eta_{CCPP} = \left(\frac{W_{GT_{net}} + W_{ST_{net}}}{Q_{f_{actual}}}\right) \cdot 100 = \left(\frac{W_{CCPP}}{Q_{CC}}\right) \cdot 100 \quad (4)$$

3.5.7 GASIFIER MODEL

The gasifier was modelled using Component 60 (Reactor) from the EBSILON® Professional v13.0 component library. It represents the core of the gasification island, where coal and/or biomass feedstock reacts with a controlled amount of oxygen and steam under high pressure and temperature to produce raw synthesis gas (syngas) consisting primarily of CO, H_2, CO_2, H_2O, and small quantities of CH_4, N_2, and other trace species.

The process is modelled as a steady-flow, non-adiabatic reactor with defined conversion efficiency and specified reaction conditions. The general form of the steady-state energy balance is:

$$\dot{m}_{fuel}\, LHV_{fuel} + \dot{m}_{O_2} h_{O_2,in} + \dot{m}_{H_2O} h_{H_2O,in} = \dot{m}_{syngas} h_{syngas,out} + \dot{Q}_{loss} \quad (1)$$

Where:

$\dot{m}_{fuel}$= mass flow rate of solid fuel (coal/biomass) (kg/s),

LHV_{fuel}= lower heating value of the feedstock (kJ/kg),

$\dot{m}_{O_2}$, $\dot{m}_{H_2O}$= mass flow rates of oxygen and steam inputs (kg/s),

$h_{syngas,out}$= specific enthalpy of the produced syngas (kJ/kg), and

$\dot{Q}_{loss}$= heat loss to surroundings (kW).

The mass balance for the gasifier is given by:

$$\dot{m}_{fuel} + \dot{m}_{O_2} + \dot{m}_{H_2O} = \dot{m}_{syngas} + \dot{m}_{ash} \quad (2)$$

The gasification process is assumed to reach thermochemical equilibrium, and the composition of the syngas is determined by the principal gasification reactions:

1. Partial oxidation:

$$\mathrm{C} + \frac{1}{2}\mathrm{O_2} \rightarrow \mathrm{CO}$$

2. Boudouard reaction:

$$\mathrm{C} + \mathrm{CO_2} \leftrightarrow 2\mathrm{CO}$$

3. Water–gas reaction:

$$\mathrm{C} + \mathrm{H_2O} \leftrightarrow \mathrm{CO} + \mathrm{H_2}$$

4. Water–gas shift reaction:

$$\mathrm{CO} + \mathrm{H_2O} \leftrightarrow \mathrm{CO_2} + \mathrm{H_2}$$

5. Methanation:

$$\mathrm{CO} + 3\mathrm{H_2} \leftrightarrow \mathrm{CH_4} + \mathrm{H_2O}$$

The cold gas efficiency which expresses the conversion efficiency of the gasifier is defined as:

$$\eta_{cg} = \frac{\dot{m}_{syngas} \, LHV_{syngas}}{\dot{m}_{fuel} \, LHV_{fuel}} \tag{3}$$

In EBSILON, the gasifier's thermochemical conversion is implemented using defined input streams (solid fuel, oxygen, and steam) and user-specified conversion efficiency, temperature, and product composition. The heat losses and conversion ratio are adjusted so that the predicted syngas composition and heating value match design or literature-reported values.

3.5.8 Air Separation Unit (ASU) Model

The Air Separation Unit (ASU) was modelled using Component 94 (Compressor) and a user-defined Macros object for the separation of oxygen and nitrogen. It provides high-purity oxygen for the gasifier and a nitrogen stream used for syngas dilution or turbine combustion control in the IGCC configuration. The ASU is modelled as a steady-state cryogenic distillation system, consisting of a series of compressors, heat exchangers, and separation columns operating under steady-flow and adiabatic assumptions.

The process involves the compression, cooling, and separation of atmospheric air into its major constituents, oxygen and nitrogen. The overall steady-state mass and energy balances for the ASU are expressed as:

Mass balance:

$$\dot{m}_{air} = \dot{m}_{O_2} + \dot{m}_{N_2} + \dot{m}_{loss} \tag{1}$$

Energy balance:

$$\dot{W}_{ASU} = \dot{m}_{air}(h_{in} - h_{out}) + \dot{Q}_{refrig} \tag{2}$$

Where:

$\dot{m}_{air}$= inlet air mass flow rate (kg/s),

$\dot{m}_{O_2}, \dot{m}_{N_2}$= mass flow rates of separated oxygen and nitrogen (kg/s),

$\dot{W}_{ASU}$= total compressor power required (kW),

h_{in}, h_{out}= inlet and outlet specific enthalpies (kJ/kg), and

$\dot{Q}_{refrig}$= net refrigeration load (kW) associated with the cryogenic separation process.

In EBSILON, the ASU is represented as a black-box subsystem that computes power consumption and flow splits based on oxygen purity, pressure ratio, and separation efficiency. For steady-state modelling, the ASU's specific power consumption (SPC) is typically defined as:

$$SPC = \frac{\dot{W}_{ASU}}{\dot{m}_{O_2}} \text{ [kWh/kg } O_2\text{]} \quad (3)$$

Typical values for cryogenic ASUs range from 0.20–0.25 kWh/kg O_2 for 95–99% oxygen purity. In the simulation, this specific power is assigned to represent the auxiliary load on the system.

The off-design behaviour of the ASU is handled using performance maps that relate oxygen and nitrogen flow rates to power consumption and efficiency at varying loads. Where detailed maps are unavailable, Stodola's correlation is used to approximate off-design mass flow variation with pressure and temperature changes, ensuring realistic prediction of ASU performance under part-load operation.

3.5.9 Syngas Cooler and Gas Cleaning System Model

The Syngas Cooler and Gas Cleaning System were modelled using Components 124 (Heat Exchanger) and 60 (Reactor) respectively from the EBSILON® Professional v13.0 component library.
Together, they form the downstream processing train of the gasification island, recovering thermal energy from the hot raw syngas and conditioning it for clean combustion in the gas turbine.

(a) Syngas Cooler Model

The syngas cooler operates as a high-pressure heat-recovery exchanger that transfers heat from the raw syngas to a water/steam circuit. It is modelled as a steady-flow counter-current heat exchanger with no external heat loss and negligible kinetic or potential-energy effects.

Mass balance:

$$\dot{m}_{sg,in} = \dot{m}_{sg,out} \quad (1)$$

Energy balance:

$$\dot{m}_{sg} c_{p,sg} (T_{sg,in} - T_{sg,out}) = \dot{m}_w (h_{out} - h_{in}) \quad (2)$$

Where:

$\dot{m}_{sg}$= syngas mass flow rate (kg/s),

$\dot{m}_w$= steam/water mass flow rate (kg/s),

$c_{p,sg}$= specific heat of syngas (kJ/kg·K),

$T_{sg,in}, T_{sg,out}$= syngas inlet and outlet temperatures (°C),

h_{in}, h_{out}= water/steam enthalpies (kJ/kg).

The heat-transfer rate is determined using the LMTD relation:

$$\dot{Q}_{sgc} = UA\,\Delta T_{lm} \tag{3}$$

The recovered thermal energy produces low-pressure steam, which is mixed with HRSG-generated steam to augment the bottoming-cycle output. For off-design analysis, Stodola's correlation is employed within EBSILON to scale mass-flow and temperature variations, maintaining realistic predictions of heat-recovery behaviour under part-load conditions.

(b) Gas Cleaning and Conditioning System Model

The Gas Cleaning and Conditioning Section removes particulates, tars, sulphur compounds, and other trace contaminants from the cooled raw syngas before it enters the post-combustion chamber. It is modelled as a steady-state reactor block (Component 60) with specified removal efficiencies for each contaminant species and an overall pressure drop to account for flow resistance through filters and scrubbers.

Mass balance:

$$\dot{m}_{syngas_{in}} = \dot{m}_{syngas_{out}} + \dot{m}_{imp} \tag{4}$$

Energy balance:

$$\dot{m}_{syngas_{in}} h_{in} = \dot{m}_{syngas_{out}} h_{out} + \dot{Q}_{loss} \tag{5}$$

where $\dot{m}_{imp}$ represents the removed impurities and $\dot{Q}_{loss}$ accounts for minor heat loss to the environment.
In EBSILON, the gas-cleaning system is implemented as a "black-box" reactor that applies these efficiency and pressure-loss parameters to modify the syngas composition and temperature before the Post-Combustion Chamber.

3.6 Exergy Analysis and environmental impact assessment

Exergy analysis was performed to complement the energy analysis by quantifying the quality of energy transformations and the irreversibilities associated with each component in the IGCC system.
All exergy calculations were conducted under steady-state operation using the thermodynamic properties obtained from the EBSILON® Professional v13.0 simulation results.

The environmental performance of both the baseline Afam VI Combined Cycle Power Plant and the retrofitted IGCC configuration was assessed to evaluate the potential reduction in pollutant emissions and overall carbon intensity resulting from the integration of gasification technology. This evaluation focused on quantifying the major gaseous emissions namely carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) and comparing their intensities across the defined simulation scenarios.

The emission assessment was carried out using a steady-state approach based on the output stream data from the EBSILON simulations. The estimated flue-gas compositions and flow rates at the exhaust stack were used to determine the mass flow of each pollutant. Carbon dioxide emissions were obtained from the component 136 on the Ebsilon component library.

This was also obtained by carrying out carbon balance in the combustion process and expressed as:

$$\dot{m}_{CO_2} = \dot{m}_f \times \frac{C_f \, M_{CO_2}}{M_C} \tag{1}$$

where $\dot{m}_f$ is the fuel mass flow rate, C_f is the carbon fraction of the fuel, and M_{CO_2} and M_C are the molecular weights of CO_2 and carbon, respectively. Similarly, sulfur dioxide emissions were determined based on the sulfur content of the fuel using:

$$\dot{m}_{SO_2} = \dot{m}_f \times S_f \times \frac{M_{SO_2}}{M_S} \tag{2}$$

where S_f denotes the sulfur fraction of the fuel. These relations allowed for consistent comparison of emission trends between the base and retrofitted models.

To enable meaningful environmental comparison, all emissions were normalized by the net electrical power output of the plant to obtain the specific emission intensity, defined as:

$$EI_i = \frac{\dot{m}_i}{W_{net}} \quad (3)$$

where EI_i represents the specific emission intensity of pollutant i, expressed in kg/MWh. The percentage reduction in each pollutant due to the retrofit was then calculated as:

$$\eta_{i_{reduction}} = \frac{EI_{i_{base}} - EI_{i_{retrofit}}}{EI_{i_{base}}} \times 100 \quad (4)$$

This provides a direct measure of the environmental benefit achieved by the IGCC configuration.

3.6.1 Modelling and Simulation of the Combined Cycle Power Plant

The modelling and simulation of the Afam VI Combined Cycle Power Plant (CCPP) and the retrofitted Integrated Gasification Combined Cycle (IGCC) configuration were carried out using EBSILON® Professional v13.0, a thermodynamic process simulation software for steady-state energy-system analysis. Each component of the plant was represented by its corresponding module from the EBSILON component library and connected through defined mass, energy and signal links to form a closed thermodynamic network.

3.6.2 Modelling of GT13E2

In the design of the GT13E2 gas turbine model for the Afam VI power plant using EBSILON® Professional v13.0, each component of the power plant weas selected from the software's component library and interconnected through defined fluid and information streams to replicate the actual thermodynamic process flow.

The design simulations were anchored on the design and operational data obtained from the Afam VI power plant, which served as the primary input for model parameterization and validation.

The table below presents the guaranteed performance specifications of the baseline GT13E2 gas turbine model under standard design conditions, serving as the reference for subsequent calibration and steady-state analysis. These data were used as boundary conditions and were specified via input parameter components in the Ebsilon component library.

The steady-state model was solved iteratively until convergence was achieved, ensuring that all mass and energy balance, thereby validating the accuracy of the gas-turbine representation prior to its integration into the full combined-cycle model.

Table 1. Guarantee Performance Data of the Simple Cycle Operation of the GT13E2 (source; Afam VI Plant Manuals and Reference Books)

	PARAMETERS	UNITS
NET ELECTRICAL OUTPUT GUARANTEE		
Guaranteed Unit Net MCR Output Simple Cycle	146.882	MW
NET HEAT RATE GUARANTEE		
Guaranteed Unit Net Heat Rate (Simple Cycle)	10,509.30	KJ/kWh
AMBIENT CONDITIONS		
Ambient air temperature	30.9	ºC
Ambient air pressure	1.013	Bar
Relative air humidity	70	%
OPERATING CONDITION		
GT load	100	% (Base load)
Gas Turbine Exhaust Temperature	531.3	ºC
Exhaust mass flow rate	503.1	Kg/s
Pressure Ratio	14	-
Lower Heating Value of fuel	48462	KJ/Kg
COMPONENT EFFICIENCIES		
Compressor isentropic Efficiency	85	%
GT Isentropic efficiency	89.5	%
GT Mechanical efficiency	99	%
Mechanical efficiency of generator	98.15	%

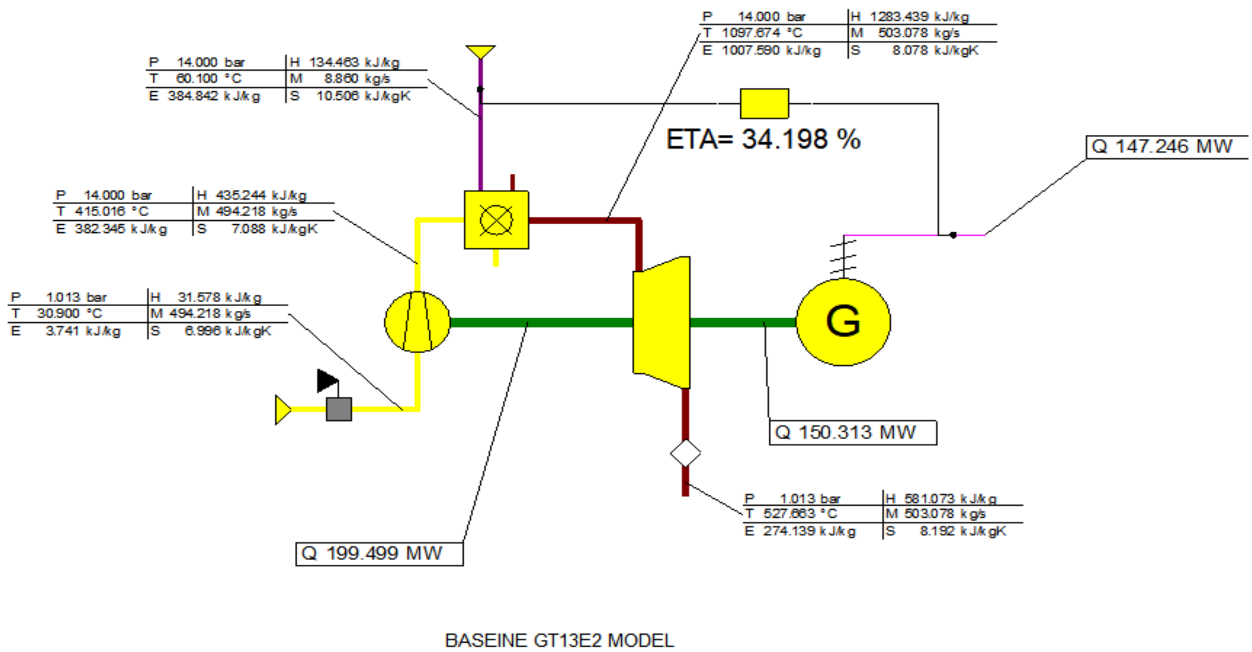


Figure 11. GT13E2 gas turbine model Using Ebsilion Software

MODELLING OF THE COMBINED CYCLE POWER PLANT SETUP

With the Brayton cycle setup, the baseline CCPP of the Afam VI was similarly model with the inclusion of a Rankine cycle in a 3×1 format. That is with 3 gas turbines, HRSGs and one dual pressure steam turbine.

In Ebsilon professional, the performance of the 3 GTs was assumed same and the stream values and output of one GT was multiplied by 3 to simulate the 3 gas turbines before being integrated into the dual pressure steam turbine.

The CCPP was modelled using design and operational data from the Afam VI power plant as well as some reference data from literatures where design and operational data is unavailable.

The table below shows the guarantee performance data obtained from Afam VI

Table 2. Performance data obtained from AFAM VI

Operating Data from the CCPP				design data
Plant units	Parameters	Symbol	units	Value
Compressor	Inlet Pressure		bar	1.013
	Inlet Temperature		°C	30.9
	Relative Humidity of Air		%	70
	Pressure Ratio		bar	14
combustion chamber	fuel mass flow rate		kg/s	8.86
	fuel inlet pressure		bar	23
	Fuel inlet temperature		°C	33
Gas Turbine	Fuel lower heating Valve		kJ/kg-k	48462
	Turbine Inlet Temperature (TIT)		°C	1091
	Temperature outlet Turbine		°C	531.3
	Net power output		MW	3*146.882
HRSG	Flue gas mass flow rate		kg/s	3*503.1
	stack temperature		°C	100.7
	HP feed water temperature		°C	152.64
	HP feed water pressure		bar	106.8
	HP feed water flow rate		kg/s	3*58.36
	LP feed water pressure		bar	5.868
	LP feed water Temperature		°C	150.9
	LP fee water flow rate		kg/s	3*.18.27
Steam Turbine	HP steam pressure		bar	100
	HP steam temperature		°C	512
	HP steam mass flow rate		kg/s	3*58.36
	LP steam temperature		°C	257
	LP steam pressure		bar	5.368
	LP steam mass flow rate		kg/s	3*18.27
	steam turbine power output		MW	217.06
Condenser	Turbine exhaust duct pressure		bar	0.2
	Condensate mass flow rate		kg/s	229.89
	Acc duct Temperature		°C	60.2
Other Thermodynamics specifications				
compressor isentropic efficiency				0.85
gas Turbine isentropic efficiency				0.895
Mechanical Efficiency				0.99
Generator Efficiency				0.9815
Specific heat of gas			kJ/kg-k	1.14

Specific heat of air		kJ/kg-k	1.005
Ratio of specific of gas			1.14
Ratio of specific of air			1.33
steam turbine isentropic efficiency			0.8

In the design mode of the Combined Cycle Power Plant (CCPP), the Rankine cycle components were integrated with the previously validated GT13E2 simple-cycle gas turbine model to form the complete thermodynamic configuration of the combined cycle system.
The respective steam pressures for the high-pressure (HP) and low-pressure (LP) turbine sections were defined within their corresponding turbine components in EBSILON® Professional v13.0. The evaporator sections of the Heat Recovery Steam Generators (HRSGs) were configured to operate in the "steam production" mode, while for the economizer and superheater components, the input condition "both cold and one steam temperature given" was selected to ensure accurate thermal matching across the heat-exchanger surfaces. After all component parameters and interconnections were specified, the complete CCPP model was simulated under design conditions, and the nominal steady-state values were successfully obtained, confirming convergence and model stability.

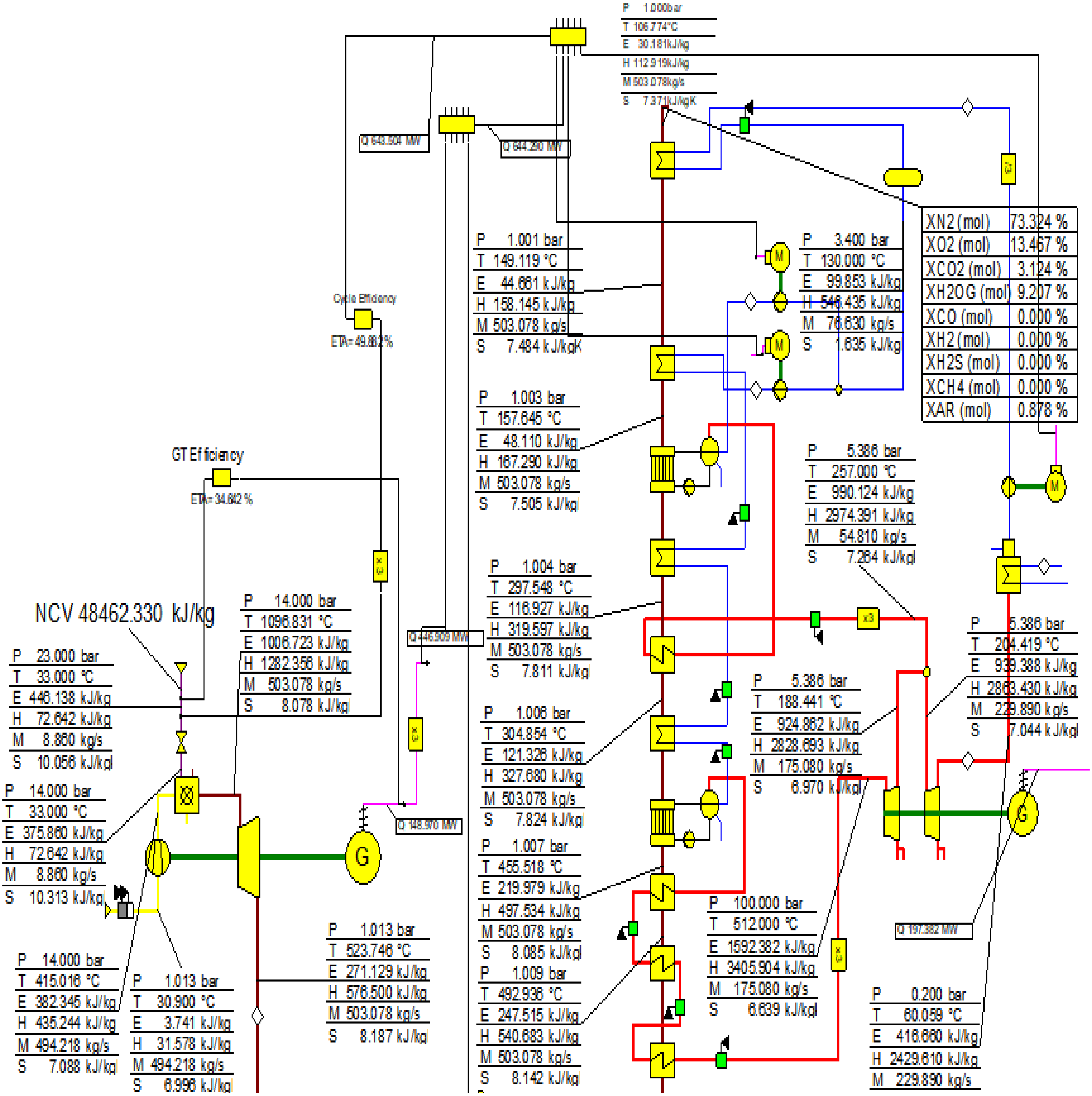


Figure 12. Modelling of the CCPP on Design Condition

The validated CCPP model thus established served as the baseline configuration for the subsequent development of the retrofitted Integrated Gasification Combined Cycle (IGCC) model, in which the gasification island and auxiliary subsystems were integrated to evaluate the performance impact of fuel flexibility and carbon reduction.

RETROFITTED IGCC MODEL DEVELOPMENT

The retrofitted Integrated Gasification Combined Cycle (IGCC) model was developed from the validated Afam VI combined-cycle configuration by introducing a gasification island and associated auxiliary systems upstream of the gas-turbine section. In this retrofit model, a dual-combustion combined-cycle configuration was adopted to enable flexible operation with both natural gas and syngas fuels.

The gasification island was initially selected from an existing demonstration plant template within the EBSILON® Professional v13.0 library and subsequently modified to obtain the required configuration for the present study. The island was parameterized using actual data from IGCC demonstration plants and relevant literature sources to achieve the target lower heating value (LHV) of the syngas.

In constructing the gasification island, the following key components were selected from the EBSILON component library: Gasifier, Air Compressor, Shift Reactor, Heat Exchangers (for syngas cooling), Pumps, and other associated process elements. Components not directly available in the standard EBSILON library were created using the Macros feature, with appropriate stream definitions and interconnections to ensure correct thermodynamic relationships and data flow between subcomponents.

The gasification island was parameterized using design-point data and representative performance parameters from established IGCC studies. The Air Separation Unit (ASU) supplied high-purity oxygen to the gasifier, where coal or biomass reacted with oxygen and steam to generate syngas. The hot syngas was then routed through a Syngas Cooler, modelled as a counter-current heat exchanger to recover waste heat as low-pressure steam. The cooled gas entered the Gas Cleaning Section, configured with fixed particulate and sulphur-removal efficiencies and an assigned nominal pressure drop to represent practical losses.

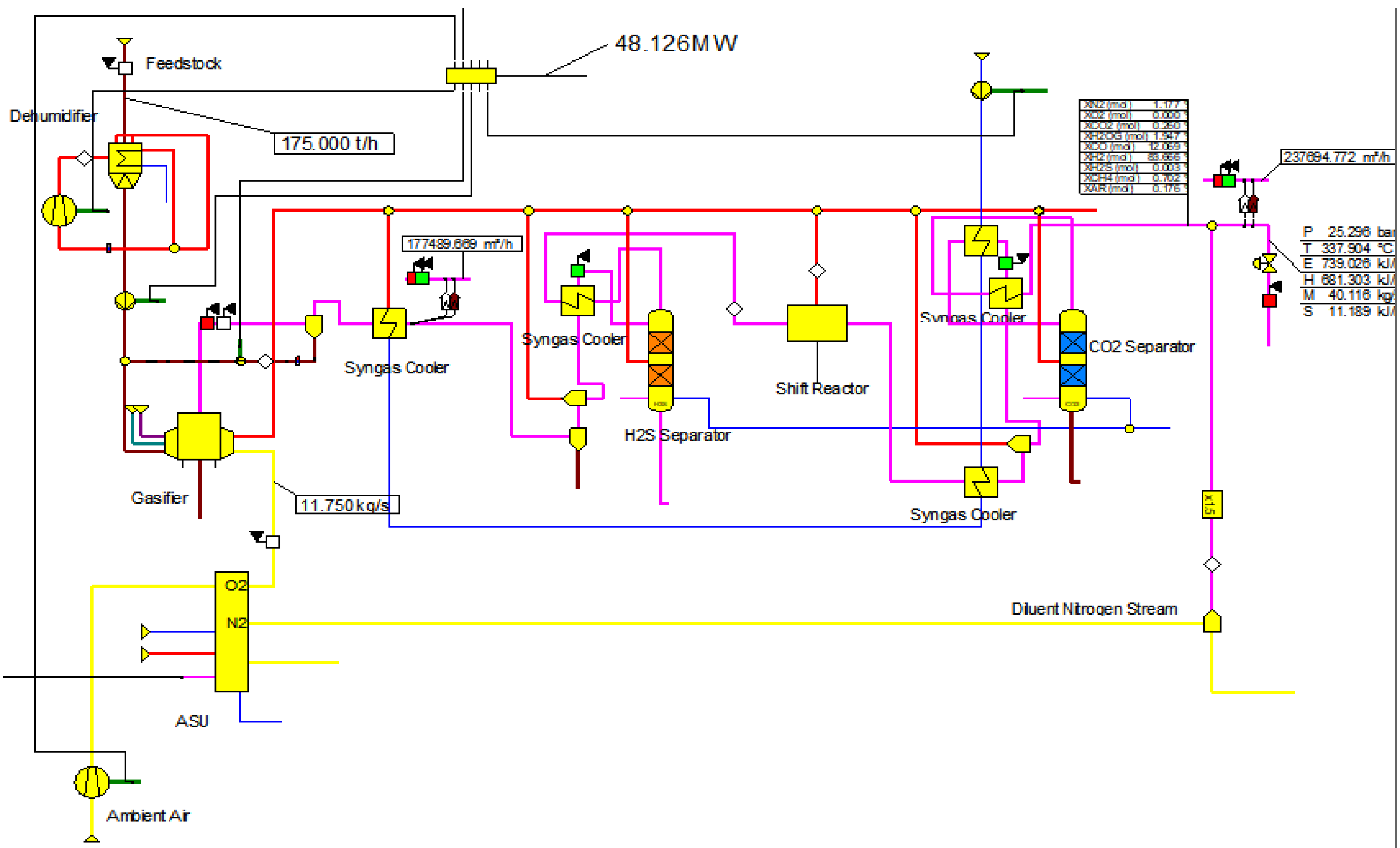


Figure 13. TOPOLOGY OF GASIFICATION ISLAND

A Post-Combustion Chamber (PCC) was introduced between the main combustor and the turbine inlet to allow stable combustion of the cleaned syngas while maintaining the designed turbine-inlet-temperature limit. A dual-fuel configuration was implemented, enabling flexible blending of natural gas and syngas in variable proportions depending on operating conditions.

An Air Preheater (APH) was also inserted downstream of the compressor discharge to recover residual flue-gas heat for preheating of the compressed air entering the combustor. This configuration reduced the supplementary fuel demand in the combustion chamber and improved the overall cycle thermal efficiency. The APH was modelled as an adiabatic counter flow heat exchanger with specified overall heat-transfer coefficient and effectiveness.

The additional steam generated in the Syngas Cooler was mixed with the low-pressure HRSG steam line using a mixer and throttle-valve arrangement. This integration increased the total steam flow and enhanced the bottoming-cycle power output without altering the mechanical design of the existing ST10 steam turbine.

All newly added components were connected to the existing CCPP network through appropriate mass- and energy-flow connectors.

Design parameters such as component efficiencies, pressure levels, and temperature limits were specified based on published data and OEM reference values.

Due to unavailability off actual gasification plant data, the operating conditions of the gasification island was varied to obtain typical syngas composition and LHV with component efficiencies in the range of some published data

Parameter	Unit	Value	Remark
Cold gas efficiency of gasifier	%	89	
Gasifier pressure	bar	27.5	
Gasifier Temperature	K	850	
Water Gas Shift Constant		0.8	
Carbon capture	%	90	
H2S separation	%	90	

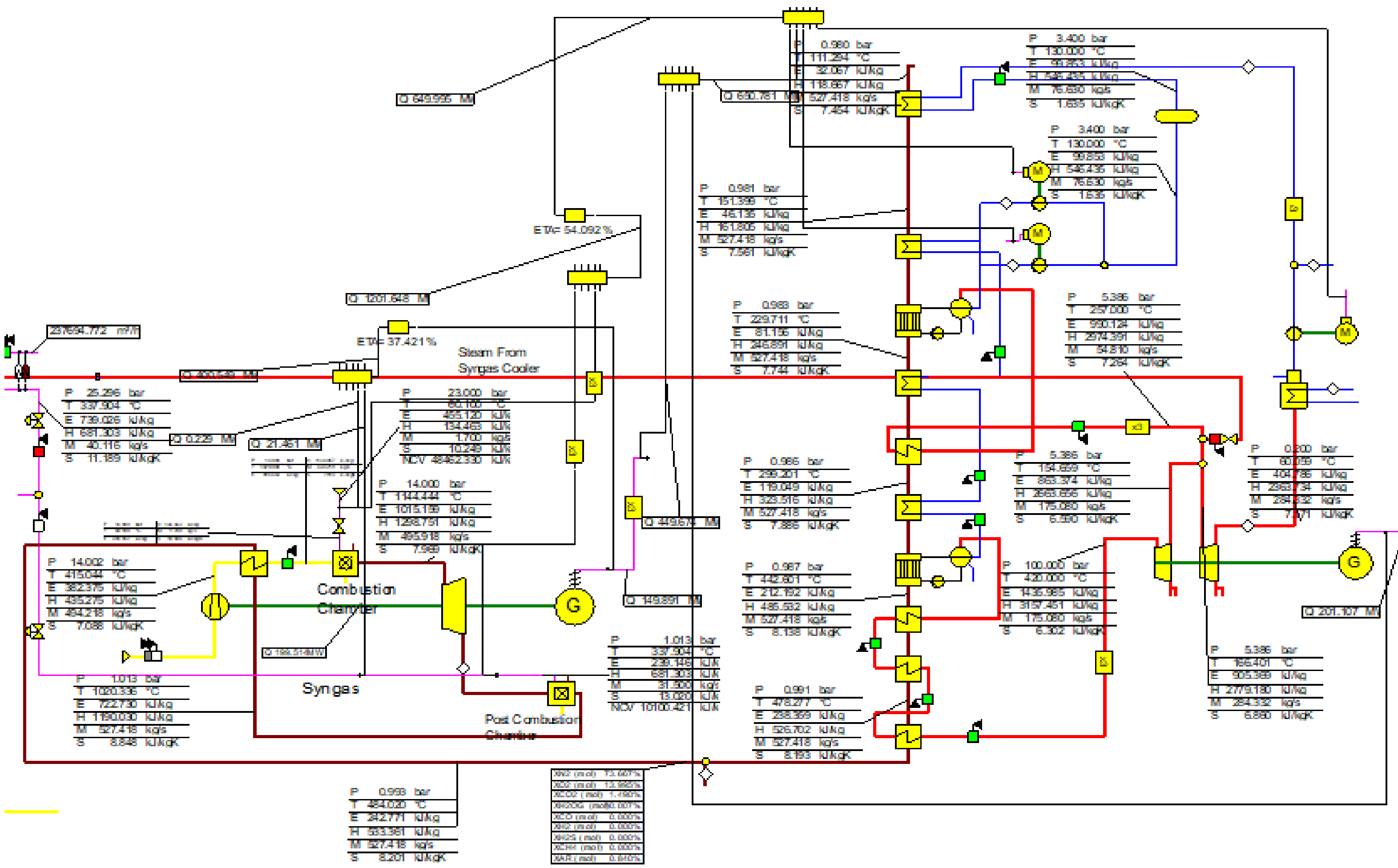


Figure 14. TOPOLOGY OF IGCC RETROFITTED AFAM VI POWER PLANT SHOWING THERMAL BLOCK

Model Validation

Model validation was performed to verify that the EBSILON® v13.0 representations of the Afam VI CCPP (base case) and the retrofitted IGCC configuration produce replicates guaranteed/OEM data and published demonstration-plant behaviour within acceptable tolerance. The baseline model was validated against design and operation data from the Afam VI CCPP. The gasification island was also validated against limited published IGCC demonstration plants and literatures.

The relative error was calculated using:

Relative error (%): $\epsilon = \frac{\text{Actual data} - \text{Simulated data}}{\text{Actual data}} * 100$

PARAMETRIC ANALYSIS OF THE IGCC MODEL

Following the successful validation of the Integrated Gasification Combined Cycle (IGCC) model, a detailed parametric analysis was carried out to achieve the project objectives. The purpose of this parametric study is to investigate the combined influence of syngas composition and co-firing ratio on both the thermal and environmental behaviour of the IGCC system. This approach enables the identification of the operating conditions that yield the best balance between efficiency improvement and emission reduction when retrofitting an existing natural gas combined cycle plant with IGCC technology. The analysis was performed using the validated EBSILON® Professional v13.0 model, maintaining all boundary conditions and component specifications as established during the validation phase.

Parameters and Assumptions

In this parametric study, the total fuel energy input was kept constant for all simulation cases to ensure that performance variations were solely due to changes in fuel composition and co-firing ratio. The syngas compositions were chosen based on values typically obtained from coal gasification processes after gas cleaning, while natural gas represented the base case condition.

Two primary parameters were considered:

1. Syngas composition and LHV which is defined by the volumetric proportions of H_2, CO, CO_2, CH_4, and N_2.
2. Syngas-to-natural gas co-firing ratio defined as the percentage of total fuel energy supplied by syngas in the gas turbine combustor. The co-firing ratio is defined as $\mathrm{CR} = \frac{\dot{m}_{f_{syngas}}}{\dot{m}_{f_{syngas}} + \dot{m}_{f_{NG}}}$ (2)

In this parametric investigation, the total fuel energy input was maintained constant across all simulation cases to ensure that any observed variations in plant performance were solely attributable to differences in fuel composition and co-firing ratio**.**

The syngas compositions were selected based on representative values obtained from coal gasification processes following gas cleaning, while natural gas served as the baseline fuel for comparison.

To further understand the thermodynamic response of the system, a sensitivity analysis was performed by varying the total heat supplied to the combustor while keeping the gas turbine and compressor configuration constant. The objective was to determine the effect of combustor heati nput on overall plant efficiency and component-level behaviour.

CHAPTER 4

RESULTS AND DISCUSSION

This chapter presents the results of the IGCC plant simulation developed in EBSILON® Professional v13.0 and provides a detailed analysis of its thermodynamic and environmental performance under various operational scenarios.

4.1 EBSILON MODEL VALIDATION

The GT13E2 model was validated by comparing its simulated performance parameters with operational data obtained from the Afam VI Combined Cycle Power Plant. The close agreement between simulated and reference data confirms that the model reliably represents the real plant's thermodynamic behaviour, thus demonstrating its authenticity and predictive accuracy for subsequent analyses.

Table 3 Validation Results

Parameter	**Unit**	**Reference (Actual)**	**Simulated (EBSILON)**	**Relative Error (%)**
Rated power (per GT)	kW	146.882	147.246	-0.2478
Thermal Efficiency	%	34.26	34.198	+0.181
Heat Rate	kJ/kWh	10,509.30	10,526.9314	-0.1678
Exhaust temperature	°C	531.3	527.663	+0.6845
Exhaust mass flow	kg/s	503.1	503.078	+0.00437
Compressor pressure ratio	-	14	14	0
Compressor isentropic eff.	%	80	80	0
Turbine isentropic eff.	%	85	85	0
LHV of fuel	kJ/kg	48462	48462	0

The assumptions made in the modelling of the power plant are as follows:

i) The simulations are performed at steady state.
ii) The transient impact caused by start-up and shut down during operation was neglected

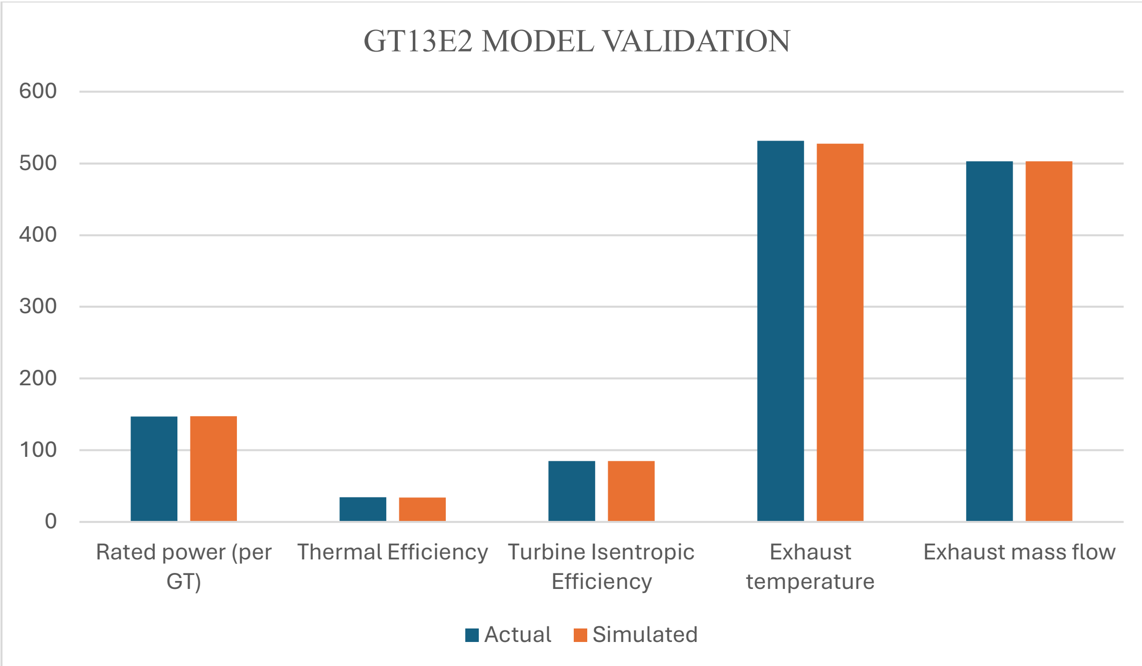


Figure 15 GT13E2 Model Validation

Effect of Syngas Composition on IGCC Performance

Following model validation, the IGCC plant was simulated using different syngas compositions. As a basis for comparison, the heat supplied to the combustors was kept constant alongside the net power output of the gas turbine. This approach isolates the effect of fuel composition from variations in thermal power supplied, enabling a direct assessment of how hydrogen and carbon monoxide proportions influence the gas turbine's thermodynamic performance.

The table below summarizes the composition of syngas used

Table 4 Syngas Composition

Case	H_2 (%)	CO (%)	CO_2 (%)	CH_4 (%)	N_2 (%)	H_2O (%)	H_2S (%)	Ar (%)	LHV kJ/kg
1	51.015	7.359	0.159	0.428	39.743	1.187	0.002	0.107	10100.421
2	19.478	38.899	0.002	0.522	39.995	0.993	0.002	0.108	7078.711

Each syngas was used for co-firing natural gas at different co-firing ratios ranging from 0% (full natural gas) to 99% syngas co-firing ratio. The cycle configuration chosen does not allow for a 100% syngas firing for the retrofit model IGCC plant. The results obtained from herein presented.

Case 1:

The syngas obtained for firing of in this case was an H_2 rich syngas with an LHV of 10100.421kJ/kg.

Table 5 Results

Syngas-Natural gas Co-Firing (%)	**Mass flow of syngas (kg/s)**	**Mass flow of natural gas (kg/s)**	**Gas Turbine Output (MW)**	**Gas Turbine Efficiency (%)**	**Steam Turbine Output (MW)**	**Gross Power Output (MW)**	**Gross Efficiency (%)**	**Net Power Output (MW)**	**Net Efficiency (%)**	**CO_2 Emissions (kg/MWh)**
0	0	8.860	148.970	34.642	197.382	644.290	50.018	643.504	49.88	137.062
25	2.761	8.284	150.064	34.949	221.796	671.987	52.167	604.7883	46.95	140.3658
50	7.332	7.332	150.484	35.047	223.646	675.099	52.409	607.5891	47.168	130.7126
75	16.354	5.451	150.482	35.047	223.646	675.093	52.409	607.5891	47.168	112.9375
95	33.940	1.786	150.377	35.022	224.808	675.938	52.474	608.344	47.227	78.19
99	40.546	0.410	150.401	35.028	227.609	678.811	52.697	610.930	47.428	64.919

Case 2:

The syngas obtained for firing was a CO rich syngas with an LHV of 7078.711kJ/kg

Table 6 Results

Syngas-Natural gas Co-Firing (%)	**Mass flow of syngas (kg/s)**	**Mass flow of natural gas (kg/s)**	**Gas Turbine Output (MW)**	**Gas Turbine Efficiency (%)**	**Steam Turbine Output (MW)**	**Gross Power Output (MW)**	**Gross Efficiency (%)**	**Net Power Output (MW)**	**Net Efficiency (%)**	**CO_2 Emissions (kg/MWh)**
0	0	8.860	148.970	34.642	197.382	644.290	50.018	643.504	49.88	137.062
25	2.816	8.449	149.949	34.923	227.977	677.825	52.621	610.043	47.359	150.564

50	7.731	7.731	149.255	34.761	229.146	676.911	52.550	609.220	47.295	161.232
75	18.481	6.16	149.244	34.759	229.146	676.878	52..547	609.190	47.292	184.128
95	44.590	2.347	149.668	34.857	229.737	678.740	52.692	610.866	47.442	239.054
99	56.734	0.573	149.885	34.908	229.887	679.542	52.754	611.588	47.479	264.531

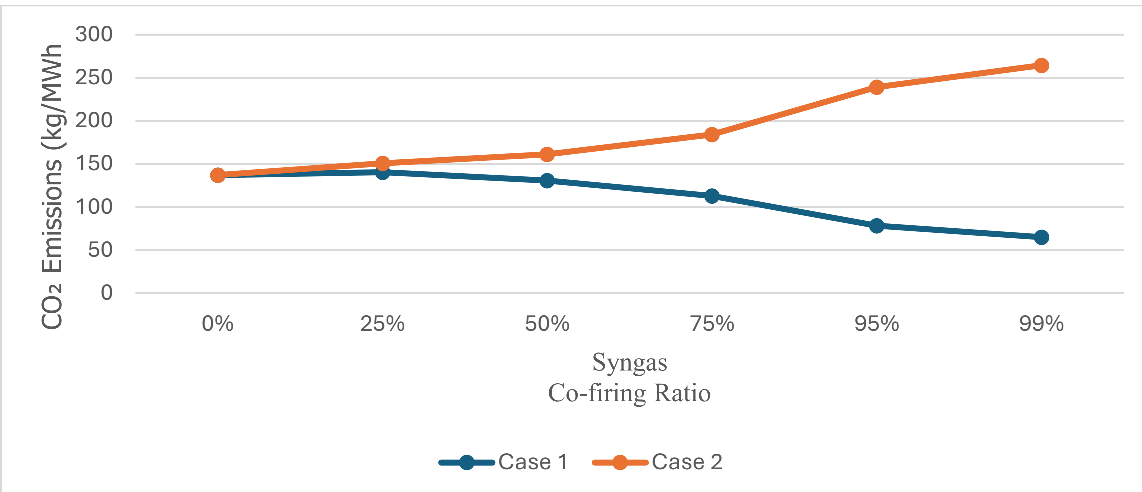


Figure 16 Results on CO2 emission

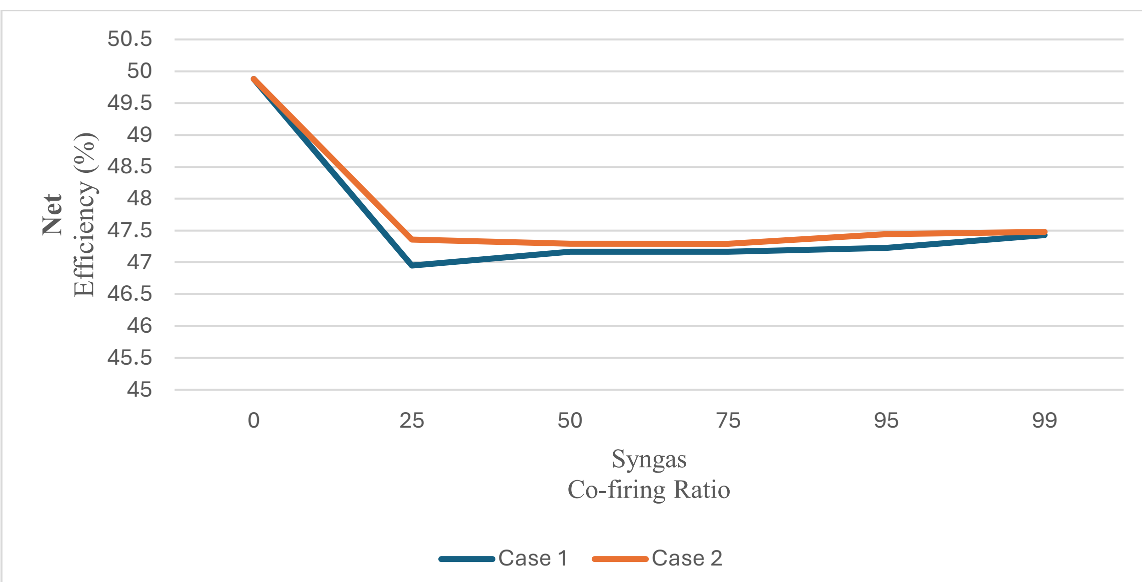


Figure 17 Results on Efficiency

In Case 1, the syngas contained a high proportion of H_2, about 51%, and a relatively low CO fraction. Results indicated that CO_2 emissions decreased progressively as the syngas co-firing ratio increased, demonstrating improved emission performance.

With 95% co-firing, the specific CO_2 emission reduced by approximately 52.6% per kWh compared to the baseline natural gas plant. This affirms that hydrogen-enriched syngas has a distinct environmental advantage, since less carbon is combusted in the combustion chamber and more of the carbon is captured in the gasification train prior to combustion.

However, a slight drop in net plant efficiency was observed during the initial co-firing stages up to 25–50%. This temporary reduction is attributed to the energy penalties associated with gas cleanup and pre-combustion CO_2 capture. At higher co-firing ratios, efficiency approached the baseline value as system thermal efficiency improved slightly and the hydrogen combustion contribution became more dominant.

For Case 2, where the syngas contained a higher CO fraction about 39% and a lower hydrogen content, a similar trend in efficiency reduction was observed. However, the environmental outcome was significantly less favorable.

Because of the higher carbon intensity of CO-rich fuel, CO_2 emissions increased markedly by about 93% compared to the baseline case, indicating poor carbon performance. Although the CO-rich mixture maintains comparable energy density, its combustion leads to higher carbon oxidation, negating the benefits of co-firing.

The results clearly establish that co-firing of hydrogen-rich syngas enhances both environmental and thermal performance, provided the system operates near the optimum co-firing ratio. Hydrogen-rich syngas minimizes direct carbon release, supports efficient heat recovery in the combined cycle, and aligns with the objectives of pre-combustion CO_2 capture, a key advantage of the IGCC configuration.

Conversely, CO-rich syngas offers no environmental benefit and incurs both efficiency and emissions penalties due to higher carbon content and less favorable thermodynamic properties.

Effect of Air Preheater Effectiveness on Cycle Performance

The air preheater plays a critical role in the retrofit IGCC configuration in minimizing the detrimental effect of H_2-rich syngas on gas turbine blades meant for natural gas combustion, thereby eliminating hydrogen embrittlement, need for advanced thermal barrier coatings and flashback risks in the topping cycle.

A parametric study was conducted to determine the effect of air preheater effectiveness (ε) on the performance of the retrofit IGCC cycle.

Effectiveness = 0.95										
$\dot{m}_{SG}$ (kg/s)	$\dot{m}_{NG}$ (kg/s)	η_{GT} (%)	ST gross Output (MW)	Gross plant Output (MW)	Gross Plant Efficiency η_{Gross} (%)	Net plant efficiency η_{net} (%)	CO_2 Emission (kg/MWh)	Total heat Supply (MW)	HRSG Exhaust Temp (°C)	HRSG Inlet Temp (°C)
38.540	0.860	34.778	239.048	688.677		47.94156	68.37458	1292.843	108.947	528.777
33.550	1.860	35.778	221.193	670.822	52.12182	46.90964	70.19448	1287.027	109.684	509.711
26.675	2.860	36.720	205.028	654.565		48.12612	71.93785	1224.093	110.41	492.052
20.920	3.860	37.618	189.464	639.037	53.47159	48.12444	73.68587	1195.096	111.038	475.572
15.255	4.860	38.499	176.267	625.670	53.52976	48.17678	75.26012	1168.827	111.565	460.68
9.700	5.860	39.219	164.623	614.030	53.58542	48.22688	76.68681	1145.89	112.014	446.987
4.250	6.860	39.929	154.366	604.016	53.63619	48.27257	77.9582	1126.135	112.392	434.627

The gas turbine output was maintained constant to provide a fixed basis for comparison, while the HRSG exit (stack) temperature was kept nearly constant across all simulations. This ensured that observed performance changes were due solely to differences in heat recovery and air preheating rather than variations in the main turbine or exhaust boundary conditions.

The effectiveness range considered for this study was 90-99%. The gas turbine output power was kept constant at 150MW and the exhaust stack temperature about 112°C

The results are presented below

Table 7 Results

Effectiveness = 0.99										
$\dot{m}_{SG}$ (kg/s)	$\dot{m}_{NG}$ (kg/s)	η_{GT} (%)	ST gross Output (MW)	Gross plant Output (MW)	Gross Plant Efficiency η_{Gross} (%)	Net plant efficiency η_{net} (%)	CO_2 Emission (kg/MWh)	Total heat Supply (MW)	HRSG Exhaust Temp (°C)	HRSG Inlet Temp (°C)
36.500	0.860	36.400	212.746	660.837	53.681	48.313	68.301	1231.030	111.542	497.254
30.700	1.860	37.344	196.477	644.820	53.705	48.334	69.997	1200.669	112.226	480.748
25.000	2.860	38.177	182.797	630.742	53.756	48.380	71.560	1173.338	112.728	465.575
19.500	3.860	38.952	171.410	620.169	53.830	48.447	72.780	1152.068	113.117	452.641
14.100	4.860	39.600	161.616	610.610	53.853	48.468	73.919	1133.829	113.437	441.426
8.800	5.860	40.122	153.320	602.135	53.828	48.445	74.959	1118.619	113.638	431.914
3.620	6.860	40.544	146.582	595.418	53.784	48.405	75.805	1107.045	113.828	424.160

The results presented in Tables 4.4(a) and 4.4(b) illustrate the influence of air preheater effectiveness (ε) on the thermodynamic performance of the retrofit IGCC plant, with gas turbine output and HRSG exhaust temperature kept nearly constant. The study was conducted for ε values of 0.90 and 0.95, corresponding to realistic limits of recuperative heat exchanger performance in industrial combined-cycle systems.

Effect on Fuel Flow Rate and HRSG Thermal Balance

An increase in air preheater effectiveness from 0.85 to 0.95 produced a noticeable reduction in the required heat input required for the same GT output. Because the preheater recovers more sensible heat from turbine exhaust gases, the air entering the post-turbine combustor is at a higher temperature. Consequently, less additional heat from fuel combustion is required to achieve the desired HRSG inlet temperature.

Effectiveness = 0.85										
$\dot{m}_{SG}$ (kg/s)	$\dot{m}_{NG}$ (kg/s)	η_{GT} (%)	ST gross Output (MW)	Gross plant Output (MW)	Gross Plant Efficiency η_{Gross} (%)	Net plant efficiency η_{net} (%)	CO_2 Emission (kg/MWh)	Total heat Supply (MW)	HRSG Exhaust Temp (℃)	HRSG Inlet Temp (℃)
35.25	1.86	33.567	259.562	708.866	52.958	47.662	69.72319	1338.539	111.159	532.411
28.92	2.86	34.734	236.583	685.389	53.043	47.739	72.11146	1292.119	111.459	528.379
22.75	3.86	35.893	214.634	663.489	53.055	47.750	74.49166	1250.548	111.747	506.051
16.73	4.86	37.051	195.52	644.871	53.140	47.826	76.64231	1213.521	112.055	485.110
10.73	5.86	38.128	177.397	626.205	53.198	47.879	78.92687	1177.100	112.382	464.805
4.9	6.86	39.191	161.828	610.889	53.314	47.982	80.9057	1145.831	112.694	446.193

Table 8 Results

This trend confirms that improving heat recovery reduces overall fuel energy input, improving the first-law thermal efficiency of the plant. The HRSG inlet temperature showed a mild rise with increasing ε, whereas the HRSG exhaust (stack) temperature remained approximately constant, indicating efficient utilization of exhaust energy and proper HRSG pinch-point control.

However, the overall gross plant output increases with an increase in the fuel input in the combustors.

Effect on Steam Cycle Performance

As the recovered heat increases, steam generation and steam turbine (ST) power output both increase slightly across the studied range. The incremental rise in steam turbine output reflects a higher rate of energy conversion in the bottoming cycle due to greater available heat at the HRSG inlet.

The improvement in gross plant efficiency validates the beneficial coupling between the air preheater and HRSG. The specific CO_2 emission decreased correspondingly, emphasizing that improved heat recovery not only enhances thermodynamic performance but also reduces environmental impact per unit of generated power.

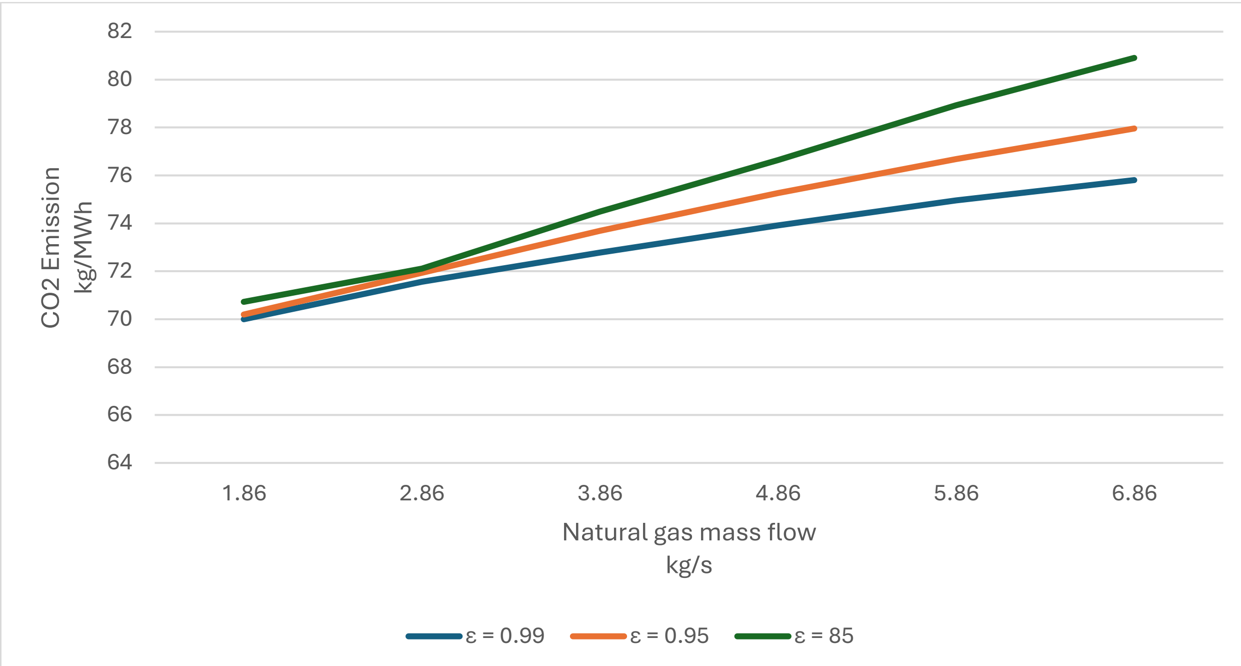


Figure 18 Results

However, the net plant efficiency of the plant suffers a reduction which is as a result of the energy penalties associated with the gasification island which consumes about 10-15% of the gross plant output. This data is in close agreement with published data in literatures. These literatures indicate that IGCC plants suffer about 10 -20% energy penalty, in terms of gross plant output, as a result of the gasification island integration with the air separation unit and capture devices the major contributors of this loss

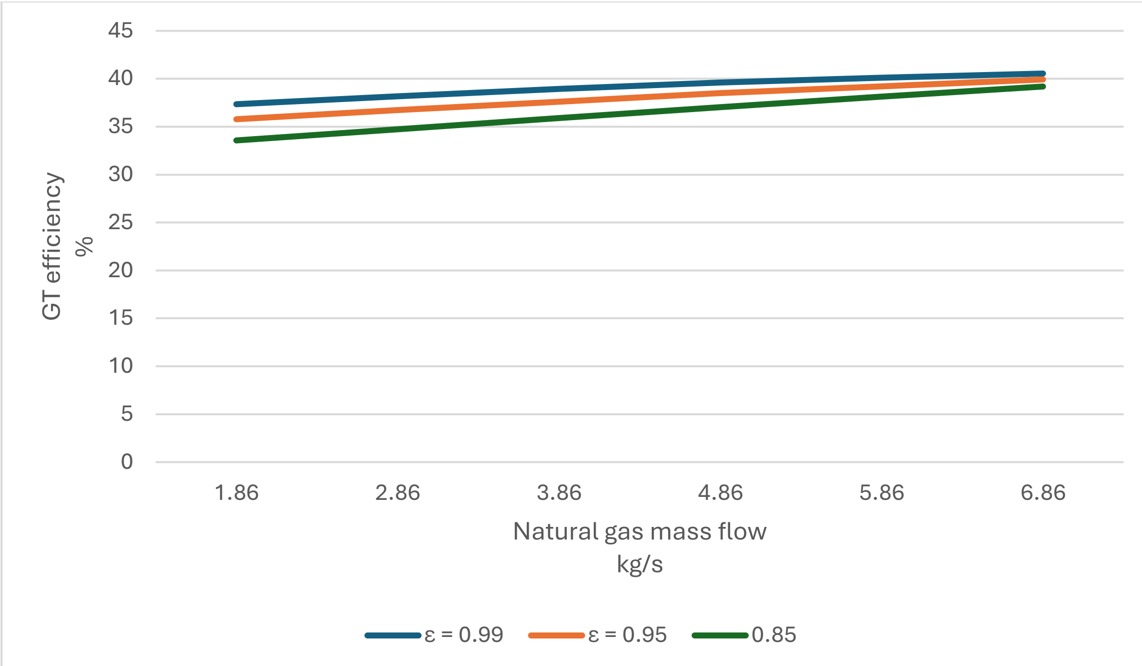


Figure 19 Results

However, the net plant efficiency of the plant suffers a reduction which is as a result of the energy penalties associated with the gasification island which consumes about 10-15% of the gross plant output. This data is in close agreement with published data in literatures. These literatures indicate that IGCC plants suffer about 10 -20% energy penalty, in terms of gross plant output, as a result of the gasification island integration with the air separation unit and capture devices the major contributors of this loss

CHAPTER 5

CONCLUSIONS AND RECOMMENDATION

The evaluation of the technical performance and environmental implications of retrofitting the Afam VI Thermal Power Plant with Non-Integrated Gasification Combined Cycle (IGCC) technology reveals that such an upgrade presents a significant opportunity to enhance Nigeria's power generation efficiency, fuel flexibility, and environmental sustainability. The Afam VI plant, currently operating on conventional combined-cycle natural gas technology, is a critical component of Nigeria's electricity supply network, yet it faces challenges related to fuel cost volatility, carbon emissions, and the need for cleaner, more reliable energy production. The proposed retrofit using IGCC technology offers a viable pathway toward addressing these challenges and aligning the plant with modern standards of energy efficiency and environmental compliance.

From a technical standpoint, the IGCC retrofit introduces advanced gasification and combined-cycle integration that allows for the conversion of solid or heavy hydrocarbon fuels such as coal, petroleum coke, or biomass into a clean syngas for power generation. This modification would enhance the plant's gross thermal efficiency, potentially increasing it from the conventional 50% to around 54% under optimal operating conditions. However the energy penalty of the gasification island accounting for about 10% of the gross power output of the plant reducing the net thermal efficiency to about 47%

The technical evaluation further indicates that retrofitting Afam VI with NIGCC technology would improve the plant's operational reliability and reduce dependence on pipeline natural gas, which is often constrained by supply disruptions. Incorporating a gasification island would diversify the plant's feedstock capability, allowing it to utilize locally available resources such as low-grade coal or agricultural residues. The syngas produced through the gasification process can also be conditioned for hydrogen extraction, paving the way for future integration with hydrogen-based energy systems and carbon capture utilization and storage (CCUS) initiatives. This forward-looking adaptability places the Afam VI plant in a strategic position to support Nigeria's transition toward low-carbon industrialization.

From an environmental perspective, the IGCC retrofit presents several positive implications. By converting solid or liquid fuels into clean hydrogen-rich syngas and utilizing advanced emission control systems, the plant can achieve significant reductions in greenhouse gas emissions, particularly carbon dioxide (CO_2), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter. Additionally, the closed-loop design of the IGCC system minimizes water consumption, reduces wastewater generation, and lowers the environmental footprint associated with thermal discharge. These environmental benefits align with global climate goals and Nigeria's commitments under the Paris Agreement to reduce national carbon emissions.

Nevertheless, the study acknowledges certain technical and economic challenges associated with the retrofit. The capital cost of IGCC technology remains relatively high due to the complexity of the gasification and syngas cleanup systems, and the need for advanced materials capable of withstanding high temperatures and pressures. Furthermore, the technical expertise required for the operation and maintenance of gasification-based systems is limited in the current Nigerian energy sector, necessitating substantial capacity building and technology transfer efforts. Despite these challenges, the long-term operational savings, environmental gains, and enhanced fuel security justify the investment, especially when viewed from a life-cycle cost perspective.

In summary, the retrofit of the Afam VI Thermal Power Plant with IGCC technology demonstrates strong potential to transform the plant into a cleaner, more efficient, and more resilient power generation facility. The integration of gasification technology would reduce thermal efficiency, enable multi-fuel flexibility, reduce harmful emissions, and create pathways for future carbon capture and hydrogen energy development. While the initial costs and technical requirements are considerable, the long-term benefits both environmental and economic make the project a strategic investment in Nigeria's energy future.

RECOMMENDATIONS

This study has shown that the major drawback of IGCC plants is the power consumed by the auxiliary of the gasification island. Further research studies should be done to reduce the energy penalties associated with the gasification plants so as reduce the energy penalties.

REFERENCES

The quantitative evaluation of two-stage pre-combustion CO2 capture processes using the physical solvents with various design parameters by Sung Ho Park, Seung Jong Lee, Jin Wook Lee, Sung Nam Chun, Jung Bin Lee, March 2015.

A Comprehensive Study of Energy, Exergy, Exergoeconomic, and Exergoenvironment Analysis of Combined Cycle Power Plant by Ahmed Sarhan Abdulsitar, Arkan Fawzi Saeed, Hatem Hasan Ismaeel, May 2025.

Assessment of energy and economic benefits arising from syngas storage in IGCC power plants by Daniele Cocco, Fabio Serra, Vittorio Tola, May 2013.

An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology, MIT LFEE 2005-002 WP by Ola Maurstad, September 2005.

Biomass-Gasifier/Aero derivative Gas Turbine Combined Cycles: Part A—Technologies and Performance Modeling by S. Consonni and E. D. Larson, July 1996.

CO2 Sequestration from IGCC Power Plants by Means of Metallic Membranes by Paolo Chiesa, Thomas G. Kreutz, and Giovanni G. Lozza, January 2007.

Closing the loop: Establishing reverse logistics for a circular economy, a systematic review by Pravin Kumar Mallick, Kim Bang Salling, Daniela C.A. Pigosso, Tim C. McAloone, December 2022.

Comparative assessment of coal fired IGCC systems with CO2 capture using physical absorption, membrane reactors and chemical looping by Sina Rezvani, Ye Huang, David McIlveen-Wright, Neil Hewitt, and Jayanta Deb Mondol, May 2009.

Climate Change in Contemporary Nigeria: An Empirical Analysis of Trends, Impacts, Challenges and Coping Strategies by S.O. Amadi and S.O. Udo, April 2015.

Development of an optimized artificial neural network model for combined heat and power micro gas turbines by H. Nikpeya, M. Assadia, and P. Breuhaus, March 2013.

Designing a Robust Cost Allocation Framework for Energy Corporations Using SAP for Improved Financial Performance by Ezinne C Chukwuma-Eke, Olakojo Yusuff Ogunsola, and Ngozi Joan Isibor, January 2018.

European Carbon Capture and Storage Project Network: Overview of the status and developments by Zoe Kapetaki, Jelena Simjanovi, Jens Hetland, 2015.

Engineering economic analysis of biomass IGCC with carbon capture and storage by James S. Rhodesa, and David W. Keith, June 2005.

Efficiency of the Energy Sector and its Impact on the Competitiveness of the Nigerian Economy by Adeola Adenikinju, January 2008.

Fuel Flexibility Influences on Premixed Combustor Blowout, Flashback, Auto ignition, and Stability by Tim Lieuwen, Vince McDonell, Eric Peterson, and Domenic Santavicca, July 2014.

FUNDAMENTAL IMPACT OF FIRING SYNGAS IN GAS TURBINES by Emmanuel O. Oluyede and Jeffrey Phillips, August 2007.

Fuel Processing Technology on the effects of running existing combined cycle power plants on syngas fuel by R. Chacartegui, D. Sánchez, J.M. Muñoz de Escalona, B. Monje, T. Sánchez, December 2011.

Gasification Technology by Lawrence J. Shadle, Natarianto Indrawan, Ronald W. Breault, and James Bennett, March 2012.

Gas turbine technology for syngas/hydrogen in coal-based IGCC by Irene M. Smith, October 2009.

Gasification processes by Higman and Burgt, 2008.

IGCC Pre-combustion CO2 Capture Using K2CO3 Solvent and Utilizing the Intercooling Heat Recovered from CO2 Compressors for CO2 Regeneration by Sheng Li, Hongguang Jin, Kathryn Anne Mumford, Kathryn Smith, and Geoff Stevens, July 2015.

Integrated SOFC and Gas Turbine Systems by FRANCESCO CALISE AND MASSIMO DENTICE D'ACCADIA, August 2013.

Integration of carbon capture in IGCC systems by Steven M. Carpenter and Henry A. Long III, 2015.

Impurity impacts on the purification process in oxy-fuel combustion based CO2 capture and storage system by H. Lia, J. Yana,b, J. Yanc, and M. Anheden, July 2008.

Modelling of combined cycle power plants using biomass by Francisco Jurado, Antonio Cano, and Jose ´ Carpio, July 2002.

Oxy-co-gasification of coal and biomass in an integrated gasification combined cycle (IGCC) power plant by Antonio Valero and Sergio Uso´n, April 2005.

Process simulation and thermodynamic analysis of an IGCC (integrated gasification combined cycle) plant with an entrained coal gasifier by Jae Chul Leea, Hyeon Hui Leea, Yong Jin Joob, Chang Ha Leea, and Min Oh, December 2013.

Reforming Natural Gas for CO2 pre-combustion capture in Combined Cycle power plant by J. M. Amann, M. Kanniche, and C. Bouallou, February 2010.

TECHNO-ECONOMIC EVALUATION OF AN IGCC POWER PLANT WITH CARBON CAPTURE by Mohammad Mansouri Majoumerd, Mohsen Assadi, and Peter Breuhaus, June 2013.

Thermal Barrier Coatings for Gas-Turbine Engine Applications by Nitin P. Padture, Maurice Gell, and Eric H. Jordan, May 2002.

Technical and economic prospects of coal- and biomass- red integrated gasification facilities equipped with CCS over time by J.C. Meerman∗, M.M.J. Knoope, A. Ramírez, W.C. Turkenburg, and A.P.C. Faaij, March 2013.

Thermo-economic evaluation of 300 MW class integrated gasification combined cycle with ash free coal (AFC) process by Sung Ho Park, Seok Woo Chung, Sung Kyu Lee, Ho Kyung Choi, and Si Hyun Lee, July 2015.

TURNING NGCC INTO IGCC: CYCLE RETROFITTING ISSUES by Juan Pablo Gutierrez, MSc., Terry B. Sullivan, P.E., and Gerald J. Feller, Ph.D., May 2006.

THE ALSTOM GT13E2 MEDIUM BTU GAS TURBINE Frank Reiss / ALSTOM Power Ltd,Timothy Griffin / ALSTOM Power Technology Ltd, Karl Reyser / ALSTOM Power Ltd, June 3-6 2002.