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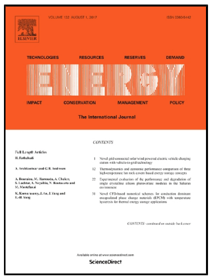

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Prospects of deployment of Jatropha Biodiesel-fired Plants in Nigeria's power sector

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ABSTRACT

This paper presents the techno-economic performance analysis of Jatropha biodiesel-fired power plants in comparison with natural gas- and diesel-fired plants. Jatropha biodiesel can be substituted for natural gas in industrial gas turbines at a slight loss in power output of ~2% and plant efficiency of ~1%. The exclusive use of the fuel in heavy duty industrial gas turbines is not economically viable at existing electricity generation prices in Nigeria, except fuels are restricted to combined cycle engines and considered as biomass power plants. The Levelized Cost of Electricity (LCOE) of the Jatropha biodiesel-fired plants varied from \$0.203-0.252/kWh, values that are below the cost of self-generated electricity (SGE) in Nigeria —\$0.45-0.70/kWh. To integrate Jatropha biodiesel into existing power plants, a minimum production-based incentive (PBI) of \$0.052-0.082/kWh can be provided for up to nine years or maximum partial fuel substitution (PFS) of 33-40% can be mandated, depending on the mode of operation. A guaranteed fuel price of \$0.18-5/gallon can be ensured, depending on electricity contract price. A carbon tax up to \$100/tCO_2 can also be imposed on natural gas-fired plants, but this does not ensure economic viability. The high cost of SGE in Nigeria uncovers an opportunity for embedded power generation.

Keywords:

Jatropha curcas, embedded power generation, gas turbines, diesel engines, self-generation, cost of electricity

LIST OF ABBREVIATIONS

CCGT	Combined Cycle Gas Turbine
CF	Capacity Factor
COT	Combustor Outlet Temperature
DPR	Department of Petroleum Resources
ECN	Energy Commission of Nigeria
FIT	Feed-in Tariff
GHG	Greenhouse Gas
HP	High Pressure
HRSG	Heat Recovery Steam Generator
ISO	International Standards Organization
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
LMP	Larson-Miller Parameter
LP	Low Pressure
NAPIMS	National Petroleum Investment Management Services
NERC	Nigerian Electricity Regulatory Commission
NGC	Nigerian Gas Company
NIPP	National Integrated Power Project
NNPC	Nigerian National Petroleum Corporation
NPE	Net Plant Efficiency
NPO	Net Plant Output
NPV	Net Present Value
NREEEP	National Renewable Energy and Energy Efficiency Policy
OCGT	Open Cycle Gas Turbine
PFS	Partial Fuel Substitution
PBI	Production-Based Incentive
PPMC	Petroleum Products Marketing Company
REP	Renewable Energy Programme
SMD	Sauter Mean Diameter
SME	Small-Medium Enterprise
SGE	Self-Generated Electricity
SPB	Simple Payback Period
TLCC	Total Life Cycle Cost
UNFCC	United Nations Framework on Climate Change
UNDP	United Nations Development Programme
URCF	Uniform Capital Recovery Factor
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

Energy is a crucial factor for the development and growth of any economy. It is the driving force behind the strong industrial and technologically advanced economies and a missing element in poorly advancing economies. In Nigeria, more than 90 million people (~55% of the population) do not have access to grid electricity [1] and less than 20% of the country's energy demand is supplied by the national grid [2]. It is typical for a power station to operate below nominal installed capacity —average plant availability as low as 9% was reported in Oyedepo [3]. Consequently, residents and industries are forced to depend on SGE or suffer the adverse effects of severe power outages, crippling costs of power supply and persistent blackouts.

According to the National Bureau of Statistics, 70.7% of businesses own or share a generator while 25.7% of households have generators [4]. The lack of access to grid electricity was the second highest barrier to businesses, as some companies spend about 50% of their income on fuelling generators [5]. The Manufacturers' Association of Nigeria estimated that 60 million Nigerians own power generating sets and spend ₦1.6 trillion ($10.4 billion) on fuel annually [6]. Based on aggregate statistics from the United Nations Commodity Trade [7], the value of imported electric generators is averaged at about $1 billion every year. This makes Nigeria the leading importer of decentralized electric generators in Africa. In reality, these data could be an underestimation, as some households and businesses have more than one generator to ensure electricity availability [8]. These conditions are linked to deteriorating generation, transmission and distribution sectors, as well as to factors such as fuel shortages, inadequate gas-networks, frequent vandalism of pipelines, poor maintenance and delayed infrastructure development. The large imbalance between demand and supply of energy is therefore, Nigeria's greatest economic bane and requires both emergency solutions and long term development. In these instances, biodiesels could be a valuable and renewable substitute for fossil-derived fuels.

Biodiesels are "fuels composed of fatty acid methyl or ethyl esters and obtained from vegetable oils or animal fats" [9]. They are produced by thermochemical conversion of triglycerides to fatty acid methyl or ethyl esters using an alcohol-catalyst dependent reaction, known as transesterification [10]. They are derived from a wide range of sources including common and readily available feedstocks such as palm oil [11], rapeseed [12], animal fats [13] and non-edible feedstocks such as *Jatropha curcas* [14] and *Miscanthus giganteus* [15]. These fuels have gained importance in recent years [16-17]; however, their adoption is limited by socio-economic and environmental concerns, as well as cost related factors. Jatropha biodiesels are of interest in Nigeria because the crop —*Jatropha curcas* from which the oil is derived— grows naturally in Nigeria [18] and has perceived environmental and socio-economic benefits [19]. Jatropha farming is yet to be practised commercially and there is little information on the cultivation of the crop in Nigeria; however, the crop is planned to be farmed along the 5000 km oil pipelines and engendered for power generation. Its use in Nigeria's power sector is identified as a means to diversify the country's energy mix. It is also recognized as a way of bringing about economic growth and development, including increased employment, income, livelihoods and community involvement, and private investment for communities involved in its production. As such, the economic feasibility of Jatropha biodiesel-fired plants will be a useful information source for early developments of biomass power generation in Nigeria.

In the literature, there is broad consensus that biodiesels and their blends have a direct application in internal combustion engines [20-22]. Studies conducted on stationary diesel engines show that biodiesels can replace conventional diesel fuel and achieve similar engine performance, as an alternative, without major engine modification —extensive reviews are provided by Xue *et al.* [23] and Dwivedi *et al.* [24]. In industrial gas turbines, engines are increasingly designed to operate using a wide range of fuels and properties, but natural gas is typically used. The use of diesel fuels is less common in gas turbines, except for start-up and as emergency back-up, and there is sparse information on the application of biodiesels. A few of the studies conducted with biodiesels in gas turbines are highlighted below: Hashimoto *et al.* [21] investigated the combustion characteristics of palm biodiesel in comparison to conventional diesel fuel and observed a similar range of adiabatic flame temperatures over a wide range of excess air ratios. Both fuels had similar ignition and combustion performance, but palm biodiesel had less tendency to form luminous flame and soot. Liu *et al.* [22] showed that the biodiesel derived from recycled cooking oil had higher dynamic viscosity and caused bigger fuel droplet sizes, particularly at lower pressure. Their study also showed that the biodiesel had a lower flame temperature and combustor pressure drop, and overall good ignition performance, which was dependent on the choice of air-assist pressure selected for ignition. Sallevelt *et al.* [25] suggest the importance of preheating biodiesels to improve spray quality and combustion performance, especially for highly viscous fuels. Relatively poor atomization quality and longer evaporation rates were observed by Bolszo *et al.* [26] during the use of soy biodiesel in a 30 kW gas turbine engine. Recommendations were made to optimize fuel atomization by adjustment of the fuel injection system. Combustion studies [27-28] carried out over a range of operating conditions using biodiesels in heavy duty and aero-derivative gas turbines (GE Frame 6B, 7EA and LM6000) indicate lower emissions than baseline values.

In Jatropha-specific studies, Rehman *et al.* [29] showed that there is a similarity in the performance characteristics of a 44 kW gas turbine test rig when operated with Jatropha and diesel oils. The reduction of viscosity of Jatropha oils by degumming or esterification was proposed. Similar analysis by Badami *et al.* [30] using Jet-A, Jatropha biodiesel, gas-to-liquid kerosene and a blend of Jatropha biodiesel and Jet-A fuel in a small turbo-jet engine, demonstrated that only a slight difference exists in the fuel mass flow rate of Jatropha biodiesel and Jet A. This difference was consistent with and proportional to the reduction in lower heating value (LHV) of the blended fuel. Combustion and spray characteristics of high viscous Jatropha oils by Fan *et al.* [31] demonstrate the need for efficient atomization. Their studies proposed the use of assisted air supply in addition to pressure-swirl atomizer at liquid viscosity exceeding 7 mm^2/s. Combustion studies by Hashimoto *et al.* [32] using Jatropha oil and biodiesel in a combustion chamber with conditions comparable to a gas turbine and employing an air-assist pressure swirl atomizer showed that flame radiation intensity and soot emissions decrease with increasing biofuel mixing ratio for both fuels. The reduced soot emission was a function of the Sauter Mean Diameter (SMD) and achieved at an optimum fuel temperature. Onabanjo et al. [33] showed that there is positive net energy balance from the use of Jatropha biodiesels in industrial gas turbine engines. These studies present the potential application of biodiesel fuels and oils in gas turbines but little is known about the cost implications.

Economic analyses including life cycle cost assessments of Jatropha biodiesel fuels and applications have been largely focused on the production costs of biodiesels. In this regard, Van Eijck *et al.* [34] showed that the cost of production of Jatropha biodiesel was higher than diesel fuel in Tanzania, Mali and India, values varying from $13-25/GJ of fuel. These costs were found to differ from country to country and mainly affected by poor product yield, high wage rate, labour requirements and cost of converting the oil to biodiesels. Similar studies by Openshaw [35], Sampattagul *et al.* [36] and Wegstein *et al.* [37] showed that the cost of production for Jatropha biodiesel is slightly higher than the retail price of diesel fuels but that these costs improved over time. Parajuli [38] proposed a 20% blend of Jatropha biodiesel in Nepal for successful integration of biofuels, using a levelized cost of production analysis. Quintero *et al.* [39] and Felix *et al.* [40] showed that production costs for Jatropha biodiesel can vary from $0.6-0.95/L while Yusuf and Kamarudin [41] and Tewfik *et al.* [42] estimated values within the range, $0.3-0.8/L. These studies are limited to cost of fuel production and none of the above has examined the economic feasibility of Jatropha biodiesel-fired plants.

Thus, from a technical point of view, can Jatropha biodiesel be used in place of conventional diesel and natural gas for power generation in Nigeria, without compromising generation efficiency? Is the use of Jatropha biodiesel as a renewable substitute for conventional diesel and natural gas economically feasible in Nigeria? What economic scenarios can allow the integration of Jatropha biodiesel into power generation without compromising technical and economic performance? This study proposes the use of Jatropha biodiesel for power generation in Nigeria and as a renewable substitute for diesel fuels. A comparative thermodynamic performance analysis coupled with economic assessment was conducted using two engine configurations (open and combined cycle) to complement the emerging use of industrial gas turbines in the National Integrated Power Project (NIPP) in Nigeria. The study compares the use of Jatropha biodiesel in these engines with two conventional fuels (natural gas and conventional diesel) to highlight the potential for its use in a low-carbon policy environment. The results are compared with the average cost of SGE and the regulated wholesale electricity generation (contract) prices in Nigeria. The study concludes by exploring different economic mechanisms of integrating Jatropha biodiesel without compromising a plant's economic viability.

2. METHOD

2.1. TECHNICAL ANALYSIS

This study models a generic independent power project in Olorunsogo, Nigeria and assumes the power station possesses four heavy-duty simple cycle gas turbines with or without combined cycle capabilities. Engines were simulated at International Standard Organization (ISO) standard temperature and pressure conditions using Aspen Plus®(v9), a process optimization software that allows the design, integration and optimization of complex chemical processes. The open cycle gas turbine (OCGT) was modelled as a single shaft gas generator (i.e. compressor, combustor and a turbine coupled to an electric generator) —Figure 1. The combined cycle gas turbine (CCGT) includes two OCGT engines laid in a 2-2-1 configuration with heat recovery steam generators (HRSGs) and a steam turbine —Figure 2. Here, the waste heat from the exhaust of the topping cycle (i.e. gas generator) was recovered in the dual pressure HRSGs, and the resulting steam was expanded up to condenser pressure by the bottoming cycle (i.e. steam turbine). The condensate was then pumped to a deaerator where it was recycled for heat recovery and utilization.

The above processes were modelled using mass flow streams (i.e. air and fuel) and unit operation blocks. The heat exchange processes in the high-pressure (HP) and low-pressure (LP) economizer, evaporator and super heater were modelled using HEATX blocks, while the deaerator and drums were simulated using FLASH2 blocks. The fuel combustion process was modelled using the RGIBBS reactor for chemical and phase equilibrium calculations, since the reactor achieves Gibbs free energy minimization without design considerations. The gas generator was limited to a maximum firing temperature of 1084^{o}C irrespective of fuel type, since modern engines possess multiple control systems such as water or steam injection modes, adjustable inlet guide vanes, bleed valves, variable stator vanes and fuel control actuators, to limit firing temperature, reduce the impact of high temperatures on metal rotor blades, ensure emission compliance and to preserve the life of engine components.

Fig. 1: Simplified flow diagram of the open cycle gas turbine

Fig. 2: Simplified flow diagram of the combined cycle gas turbine

Performance assessment was carried out for both engine configurations at ISO conditions using natural gas. These engines were simulated after the GE 9E Frame engine; hence validation of the engine models was achieved by comparing outputs to publicly available information. Considering local variations in ambient temperatures, off-design analyses were performed with comparative engine assessment using natural gas, conventional diesel and Jatropha biodiesel fuels. The input data and model assumptions for engine simulation are listed in Table 1 for OCGT and Table 2 for CCGT respectively. A generic Jatropha biodiesel production system —cultivation, harvesting, oil extraction, conversion via transesterification and associated transportation processes— is described elsewhere in Onabanjo *et al.* [43], while fuel chemical composition, as defined in Aspen Plus®, is listed in Table 3.

Table 1: Engine input data and model assumptions for the OCGT/Topping cycle

Table 2: Engine input data and model assumptions for the Bottoming cycle

Table 3: Parameters/Properties for the different fuels

2.2. COST ESTIMATION

The operating cost includes fuel cost, and associated costs of operating the different utilities such as pumps and drivers. The maintenance costs cover fixed and variable maintenance costs. The fixed maintenance cost was calculated using the fixed maintenance cost factor in Table 4 multiplied by the total power output of the engine. The variable maintenance cost takes into account the influences of fuel properties and ambient conditions on hot gas path components. This is based on the assumption that thermal stress and creep are the dominant failure modes in the baseload operation of these engines. Since the first stages of the turbine blades encounter extreme hot conditions and are critical components in maintenance schedules, the gas path for the first stages of the turbine was sized appropriately by calculating the blade height and distance from mid-shaft to mid-blade. The blade temperature and time-to-failure were then estimated using the Larson-Miller Parameter (LMP) method [44-46]. These calculations involve an initial estimation of the centrifugal force acting on the blade at the mid-root section, a function of the design point rotational speed of the turbine. The estimations offer an introductory value for the variable maintenance costs for the three fuel scenarios. A step-by-step description of the method for the variable maintenance cost estimation is outlined in Onabanjo *et al.* [47]. Fuel costs were calculated based on the fuel consumption rate of the engines. The local market price of both biodiesel and conventional diesel fuels were assumed to be \$5.5/gallon based on the bulk pump price of diesel fuels in Nigeria and with the consideration that fuel prices of Jatropha biodiesel would have to be competitive with diesel for successful adoption. The local price of natural gas was \$2.8/MMBTU [48-51]. These fuel costs account for the cost associated with the production and transportation of the fuel to the power plants. Emission costs of the engines were calculated based on carbon balance and using the carbon emissions of the flue gas, but this assumes that the fuel is completely combusted. A zero carbon tax rate was applied to the base case study; however, a scenario analysis considered a range of carbon tax of \$0-100/tC. All costs including fixed maintenance costs and capital costs, as inputted in the economic model, are outlined in Table 4.

Table 4: Input in the Economic Model

2.3. ECONOMIC ANALYSIS

The economic analyses for the Jatropha biodiesel-fired plants were conducted in comparison with the natural gas- and conventional diesel-fired plants using economic parameters [50, 52-53] such as: i) Net Present Value, ii) Levelized Cost of Electricity and iii) Simple Payback Period.

Net Present Value (NPV) defines the economic viability of a project as it examines the revenues and costs over a discounted time [50]. NPV was calculated using equations 1, assuming an annual real discount rate equal to the project's weighted average cost of capital (WACC) as provided by [49]. A constant dollar cash flow was used at the end of the period, i.e. 2012, with an annual escalation rate of 11% apart from the base year.

$$NPV = -\,Initial\ Investment + \sum_{t=1}^{T} \frac{Net\ Cash\ Flow_t}{(1+d)^t} \qquad \text{eqn. (1)}$$

where d is the annual real discount rate in %, T is the plant's project life in years or analysis period and t is the net cash flow each period. The depreciation rate assumes the salvage value at the end of the project is 0. There are no further investments, so the annual capital cost after the first year is 0.

Levelized Cost of Electricity (LCOE) accounts for the total life cycle cost (TLCC) when discounted to the base year [50-51]. It considers the estimated cost of installing and operating projects over a period of time, and is used to compare projects under different operating conditions. It primarily describes the TLCC per every unit of energy generated over the project life. In this study, LCOE was calculated using equations 2-4 and is expressed in $/MWh.

$$LCOE = \left(\frac{TLCC}{Q}\right) URCF \qquad \text{eqn. (2)}$$

$$TLCC = \sum_{t=1}^{T} \frac{C_t}{(1+d)^t} \qquad \text{eqn. (3)}$$

$$URCF = \frac{d(1+d)^T}{(1+d)^T - 1} \qquad \text{eqn. (4)}$$

where Q – annual energy output (MWh), URCF – uniform capital recovery factor

The outputs for the OCGT and CCGT were compared with those of SGE in Nigeria. The latter analysis was conducted using the primary data in Table 4, as obtained from a local analytical laboratory and household.

Simple Payback Period (SPB) is a quick assessment measure that defines the number of years required to recover the cost of investment in the project [50]. This was calculated using equation 5 and is expressed in years.

$$SPB = \Delta I_n \leq \Delta S_n \qquad \text{eqn. (5)}$$

where ΔI_n – non-discounted capital costs, ΔS_n – non-discounted summation of annual cash flows

Sensitivity analysis was then carried out to determine the individual influence of key parameters, such as capacity factor, company tax rate, depreciation rate, escalation rate, capital cost, maintenance factor (fixed and variable) and fuel price, on the economic performance of the Jatropha biodiesel-fired plants.

3. Results and Discussion

3.1. Engine Validation

Table 5 presents the outcomes of the simulated engines (OCGT and CCGT) when operated on natural gas with net heating value (HV_{net}) of 49.07 MJ/kg at ISO conditions. The results show a relatively low percentage error for the different parameters (i.e. power output, heat rate, thermal efficiency, exhaust mass flow and exhaust gas temperature) when compared to the MS9001 E engine [54]. The percentage error ranged between 0.24% and 1.79% for the OCGT and between 2.27% and 4.01% for the CCGT. The slight differences in heat rates and net plant efficiencies for both engines are indications of a variation in the HV_{net} of natural gas, a value which was not reported in [54].

Table 5: Engine Validation of the Natural Gas OCGT and CCGT engines at ISO Conditions

3.2. Engine Performance Analysis

Table 6 shows the results of the engine performance analysis based on the use of various gas turbine fuels (i.e. natural gas, diesel and Jatropha biodiesel) in OCGT and CCGT engines under site conditions. Considering the open cycle configuration, the results show a decrease of 1.79% in net plant output (NPO) and 0.92% in net plant efficiency (NPE) of the Jatropha biodiesel Fired OCGT Plant (-FOP) when compared to the natural gas case. These values correspond to an increase in the heat rate of the engine of 0.96%. A similar comparison with diesel-FOP shows that the engine performance of the Jatropha biodiesel-FOP is slightly higher by ~1%. Here an increase in NPO and NPE of 0.94% and a decrease of 0.98% in heat rate are observed for the Jatropha biodiesel-FOP in comparison with the diesel-FOP. This positions the natural gas-FOP as the highest performing power plant and diesel-FOP as having the lowest performance. For the combined cycle configuration, the Jatropha biodiesel-Fired CCGT Plant (-FCP) had a minimal loss of 1.43% and 0.60% in NPO and NPE respectively. The reduction in NPE was complemented by an increase in heat rate of 0.59% when compared to the natural gas case. Similarly, the diesel-FCP had a reduced NPO and NPE, but to a lesser degree than the OCGT counterpart, with values of 2.02% and 1.19% respectively in comparison to the natural gas case. This positions the Jatropha biodiesel-FCP as having a slightly better performance than the diesel-FCP but at a lesser output than the natural gas case. Here, the NPO and NPE of the Jatropha biodiesel-FCP increased by 0.60%, and the heat rate reduced by 0.66%.

Table 6: Technical Analysis of the OCGT and CCGT engines (different fuels) under Site Conditions

The slight differences observed in the NPO, NPE and heat rate for the different fuel scenarios are relatively small compared to the engine's fuel flow rate. As mentioned in section 2.1., the gas generators were modelled with a maximum firing temperature and this setting ensures that fuel flow rates are suitably adjusted such that firing temperatures are reached but not exceeded. It also ensures that a relatively constant combustor outlet temperature (COT) is reached, which in turn preserves turbines' metal blades and the life of engine components. Hence, the maximum engine firing temperature has necessitated the adjustment of the engine's fuel flow rate, such that a considerable increase of nearly 14% and 33% was observed in the diesel- and Jatropha biodiesel-fired plants respectively, in the place of natural gas. These significant fuel adjustments are as a result of the reduced heating values of the fuels. In this study, the diesel and Jatropha biodiesel fuels have HV_{net} of 42.58 MJ/kg and 36.58 MJ/kg respectively, corresponding to a reduced energy content of 13% and 25% when compared to the HV_{net} of natural gas.

Another added influence is the chemical composition, primarily the carbon, hydrogen and oxygen content of the fuels. Meher-Homji *et al.* [55] reported that gas turbines operating on natural gas will produce a range between 2% and 3% of power output more than engines using distillate oil. This is because of the relative higher specific equivalent power obtained from natural gas, a function of the molar hydrogen-to-carbon (H/C) ratio of the fuel. In this study, the natural gas is primarily composed of methane, and has a molar H/C that is about one-third of the mixture, while the molar H/C of the diesel and biodiesel fuels is less than one-fifth. An analysis of the flue gas composition shows that the mass H/C ratios are 0.61, 0.15 and 0.19 while mass hydrogen-to-oxygen H/O ratios are 0.144, 0.088 and 0.093 for natural gas, diesel and Jatropha biodiesel respectively. These values are in the order of the specific equivalent power for the respective power plants (OCGT and CCGT) and within the range of 2-3%. And, although there is a larger carbon content in diesel and Jatropha biodiesel fuels, which can contribute to the further production of carbon dioxide (CO_2) in the flue gas and increased gas mass flow and specific heat capacity of the combustion products, this is counterbalanced by the lower LHV fuels. The loss of NPO and NPE for the diesel- and Jatropha biodiesel-FOP/FCP engines is therefore as a result of the relatively large amount of fuel that is added to the system to compensate for the lower LHV fuels.

In summary, the engine performance analysis shows that the Jatropha biodiesel fired plants have a close performance characteristic and slightly improved performance compared to conventional diesel-fired engines, hence Jatropha biodiesel can be considered as an alternative. The results also show that Jatropha biodiesel can be substituted for natural gas in industrial gas turbines and for distributed or embedded power generation in Nigeria, particularly for power stations in remote locations with limited access to the existing natural gas distribution networks. The use of the fuel however comes at a cost of increased fuel consumption with slight loss in power (~2%) and plant efficiency (~1%). Since fuel costs may account for over two-thirds of the operator's annual operating cost, the above results show that the use of Jatropha biodiesels in CCGTs is the best alternative. This is due to the additional power output derived from the bottoming cycle at no added heat input, hence a reduced specific fuel cost with increased potential earnings for the power station.

The differences observed between the data for ISO and site conditions in the natural gas-FOP/FCP are mainly due to ambient effects. Here, the increased ambient temperature reduces the density of the air flowing into the compressor. This consequently reduces the compressor delivery pressure and air flow rates going through the engine, and causes an overall reduction in specific power output and thermal efficiency of the engine. The thermal efficiency is worsened because more fuel is consumed in order to maintain the engine's COT. Meher-Homji *et al.* [56] report an ideal reduction in power output between 0.3% and 0.5% for every degree Fahrenheit rise in ambient temperature. Bacha *et al.* [57] report a 0.5% to 0.9% drop in power output for every 1°C rise in temperature. Similar trends are reported in Alhazmy and Najjar, [58], Mohanty and Palaso Jr. [59], and Kakaras *et al.* [60]. In this study, an increase in ambient temperature caused a 0.44% loss in NPO and 0.28% loss in NPE for every 1°C rise in temperature.

This study has not examined the fuel effects on the durability of engine components. It is nonetheless worth mentioning that the use of liquid fuels requires that the fuel pressure level is correctly set to ensure that the minimum fuel supply pressure is reached and accounts for pressure in the combustor and losses in the fuel system [55]. Also, effective fuel atomizers would be required for optimum fuel evaporation rates and to ensure a thorough mixing of the fuel and air. Silva *et al.* [61] have demonstrated the importance of employing control strategy such as air bleeds and guide vanes in the event of utilizing relatively LHV fuels to optimize the operational conditions of the engine and ensure safe operation. Meher-Homji *et al.* [55] also showed how a power correction factor could be applied to engines operating on fuels with LHV and containing inert gases and varying C/H ratio.

3.3. Economic Analysis

The results of the economic analysis for the Jatropha biodiesel-fired plant in comparison with the natural gas- and conventional diesel-fired plants are presented in Table 7. The results show that the LCOE of the Jatropha biodiesel-FOP and -FCP are \$0.252/kWh and \$0.203/kWh respectively. These values exceed the current and proposed wholesale electricity generation price for gas power plants in Nigeria. The NERC outlines the wholesale electricity generation price for 2012 new entrants' gas power plants as \$0.081/kWh and for 2016 new entrants' gas power plants as \$0.113/kWh. Although the commission presents a wholesale generation contract price of \$0.232/kWh for biomass power plants, there was no direct reference to biodiesel-fired plants. Based on the regulated electricity generation price of \$0.113/kWh, Table 7 shows that the NPV of the Jatropha biodiesel-FOP is in deficit (i.e. -\$1614 million), as opposed to the positive NPV of \$3,295 million for the natural gas-FOP. The SPB for the Jatropha biodiesel-FOP exceeded the lifetime of the project as compared to the SPB of ~5 years for the natural gas-FOP. The B/C ratio of the natural gas-FOP was 4.45 while the Jatropha biodiesel-FOP had none. Comparing the CCGT alternatives, however, the results show that the LCOE for the Jatropha biodiesel-FCP is 10% higher than the diesel-FCP, nearly 3 times higher than the natural gas-FCP and 79% higher than the electricity generation price of \$0.113/kWh, but it is 14% less than the contract price for biomass power plants. Here, the NPV of the Jatropha biodiesel-FCP is \$439 million, SPB is about 20 years and B/C is 0.06 at the electricity generation price of \$0.113/kWh. These results imply that Jatropha biodiesel-fired plants would require financial support to be as economically viable and competitive as the natural gas plants.

Table 7: Economic Analysis of OCGT and CCGT at Site Conditions

Analysis of the LCOE in different countries by Salvador [62] indicates a range of $0.114-0.141/kWh for natural gas-FCPs in the United Kingdom at 80% capacity factor (CF) and $0.061-0.069/kWh in the United States at 60-80% CF. The rest of the world were averaged at $0.069/kWh at 68% CF according to the same report. These values varied from $0.05-0.15/kWh at 10% discount rate based on another report [63]. Typically, the LCOE of OCGT engines are usually higher than those of the CCGTs, because OCGTs are often used as peaking plants. For baseload operation, Salvatore [62] showed an LCOE of $0.08/kWh at 10% discount rate and a CF of 85-90% for gas-fired OCGT engines, and ~$0.4/kWh at 85% CF and 10% discount rate for diesel-fired OCGT engines in South Africa. Silinga and Gauché [64] also showed that the LCOE for diesel-fired OCGT in South Africa was as high as $0.63/kWh, while the LCOE of gas-fired OCGT engines was reported to be in excess of $0.10/kWh and up to $0.26/kWh under different economic conditions [65-66].

3.3.1. Average Cost of Self-Generated Electricity in Nigeria

The average cost of SGE in Nigeria was estimated using the data of a small-medium enterprise (SME) with 20 staffing capacity and a typical household in Delta State, Nigeria. The SME operates two diesel engines (100 kVa and 80 kVa) for 10 hours daily while the household operates a 22 kVa diesel engine for 6 hours daily balanced by the grid power supply. The rest of the day was considered as in a blackout condition, therefore additional energy costs or grid connections were not included in the analysis; however, the analysis considers incurring the costs of the diesel-powered engines, and the operating and maintenance costs for a 20-year period, but excludes the costs of emissions at the industrial power plants —Table 8.

Table 8: The Average Cost of Self-Generated Electricity in Nigeria

The LCOE for SGE was $0.19/kWh for the SME and $0.46/kWh for the household based on the use of diesel generators for 10-hours' and 6-hours' duration respectively. Considering a continuous engine use operation, the analysis shows that the LCOE for SGE can increase up to 0.45/kWh and $0.70/kWh for the SME and household respectively. These values are considerably higher for the household than the SME, due to the small capacity and low efficiency of privately-owned, small diesel engines. These values are similar to the outcomes of the survey in Lagos State [8]. Ogunbiyi [8] showed that the average cost of SGE in 87% (1,723 homes) of Magodo I residents in Lagos State is ₦52.04/kWh (~$0.32/kWh at 2012 Naira-$ exchange rate of 161). This value accounts for the cost of purchasing the diesel/petrol generators and the daily fuel consumption of the engines for a 7-hour period, but excludes the cost of maintaining the engines. The electricity consumption in Nigeria is averaged at 149kWh/capita, a value that is significantly low compared to countries such as South Africa (4315kWh/capita) and Brazil (2438kWh/capita) [67]. Electricity supply in Nigeria has not exceeded 5 GW, while electricity demand was estimated at ~13 GW in 2012 and projected to increase to 41 GW in 2015 and 88 GW in 2020. About 2.6 GW of decentralized diesel generators are said to be in operation in the country and over 85% of local companies and industries own one or more generators [68]. This large and increasing energy demand in poor power situations therefore opens a potential market opportunity for embedded power generation.

Considering the high cost of SGE in Nigeria, the results in Table 7 show that the LCOE for Jatropha biodiesel-fired plants could be three times more than the natural gas power plants; however, the costs of SGE in Nigeria are indications of prospective market opportunities for Jatropha biodiesel-fired plants. The household benefits from a reduced energy cost of 64% and 71% from the JT-FOP and -FCP engines respectively in comparison to a continuous use operation of diesel generating sets; the SME with a similar electricity consumption pattern will benefit from a 44% and 55% reduced electricity cost respectively. This is a substantial reduction in operating costs, since businesses can consume more than 10 GWh of electricity per annum. Even for the SME, where the LCOE for SGE during active business operating hours appears smaller than the base-case scenarios of the Jatropha biodiesel-fired plants, the cost of shutting down business operations and industrial equipment as well as loss of potential gain or opportunity costs can exceed any reasonable benefit. Based on these considerations, the study further investigated the possibility of integrating Jatropha biodiesel in power plants using different forms of financial instruments that can ensure Jatropha biodiesel-fired plants are as competitive as natural gas plants. These employ a means to reduce the TLCC and increase the revenue of the power plant, or business model that can accommodate a multiple use of fuels.

3.4. Economic Scenarios for Integrating Jatropha Biodiesel into the Energy Mix

The 'Renewable Energy Programme' (REP) is the main public institution guiding the activities of renewable energy development in Nigeria. This initiative was launched by the Federal Ministry of Environment to transit the country to a clean, reliable and sustainable energy supply and to ensure that targets on emission reductions as a party to the United Nations Framework on Climate Change (UNFCC) and sustainable energy development as part of the Millennium (*now Sustainable*) Development Goals are met. To support these activities, the Energy Commission of Nigeria (ECN) and the United Nations Development Programme (UNDP) developed a Renewable Energy Master Plan, which sets out a road map for integrating renewable energy sources in existing electricity generation and distribution systems. This is supported by the National Renewable Energy and Energy Efficiency Policy (NREEEP), a policy framework designed to power generation capacities and share of renewable energy sources in Nigeria. Based on the REP initiative, the Nigerian Biofuel Programme was established, which is supported by the Nigerian Biofuel Policy to reduce the country's dependence on fossil fuels and increase the energy and fuel mix of Nigeria through local production of biogas, biodiesel and bioethanol. The initiative has involved a number of stakeholders: local distilleries, refineries and organizations such as the Nigerian National Petroleum Corporation (NNPC), Department of Petroleum Resources (DPR), National Petroleum Investment Management Services (NAPIMS), Petroleum Products Marketing Company (PPMC) and Nigerian Gas Company (NGC), each playing their role. NAPIMS is expected to invest in biofuel ventures, DPR acts as a regulatory body, while NNPC and PPMC receive the output from the distilleries and refineries and blend them with refined petroleum products for distribution to the end consumers. NGC is mainly involved in the biogas project and acts as a receiver and distributor of any required gas supply in these initiatives. Some of the bio-ethanol and biodiesel projects include the 6-automotive biofuel project using sugar cane and cassava feedstocks, two ethanol refineries using sorghum and 12 other bio-ethanol projects [69]. Jatropha was recently approved to be grown nationwide, and possibly intercropped with maize and cassava plants. Thus, the following sub-section examines the economic scenarios by which Jatropha biodiesel can be integrated into existing power plants or used in dedicated power plants for embedded power generation.

Kost *et al.* [70] made note of the important role conventional diesel power plants play in electricity generation in Middle East countries, accounting for nearly 88% of the energy mix in Saudi Arabia. This was only achievable with fuel subsidization, which is a highly contentious issue in Nigeria. Despite the cost of fuel subsidy and related incentives, there are potential economic benefits. In developed economies, renewable fuels have appreciably penetrated the energy mix of many countries because of government support and platforms such as production-based renewable incentives, tax credits, and subsidy programmes. As a result, and in addition to advances in technology, the cost of renewable energy has been declining and penetration of renewable energy production has increased substantially. For instance, the UK operated a minimum feed-in tariff system that pays an energy generator a minimum guaranteed amount for any renewable energy generated (used or sold to the grid) over a period of years. In the US, the energy generator receives a tax credit that has lowered the electricity cost of production from renewable energy sources. This has brought about significant economic benefits and growth, and can be adopted by developing economies to ramp up renewable energy projects, particularly for biodiesel-fired plants. This study considers four support scenarios: a) the provision of production-based incentive, b) mandatory renewable energy fuel integration with and without renewable tax relief for the hours a plant operates on renewable fuels, c) carbon tax and d) fuel subsidy.

3.4.1. Production-Based Incentive (PBI)

At the NERC regulated price of \$0.113/kWh, Figure 3 illustrates that a PBI support of up to \$0.082/kWh and \$0.052/kWh would be required to support the Jatropha biodiesel-FOP and -FCP plants respectively to ensure these plants are as competitive as their natural gas counterparts. A PBI support throughout the life of the project ensures that the Jatropha biodiesel-FOP benefits from an SPB of six years, B/C of 0.42, and NPV of \$3 billion. The Jatropha biodiesel-FCP on the other hand benefits from an SPB of 11 years, B/C of 0.32 and NPV of \$2.6 billion. For a limited period of time, a PBI support of \$0.082/kWh for seven years and \$0.052/kWh for nine years can ensure the respective Jatropha biodiesel-FOP and -FCP plants recover their TLCCs at least. If Jatropha biodiesel-fired plants are considered as biomass power plants, a PBI support of \$0.01/kWh can ensure that the TLCC of the Jatropha biodiesel-FOP is recovered, but the Jatropha biodiesel-FCP requires no support as its LCOE is below \$0.232/kWh. In a worst case scenario, where the Jatropha biodiesel-fired plants are required to be as competitive as the gas-fired plants, a PBI support of \$0.102/kWh and \$0.073/kWh would be required to support the Jatropha biodiesel-FOP and -FCP plants respectively. Fig. 3: The LCOE of the Jatropha biodiesel-fired plants with production-based incentive (PBI) support

Salvador [62] showed that feed-in tariffs (FITs) have driven generation costs down and improved the penetration of renewable energy technologies —64% for wind energy technologies and 87% for photovoltaic cells. A report by Rickerson *et al.* [71] showed that FITs are well established in the electricity sector in developed countries but only a few developing countries have successfully integrated this. Some of the benefits highlighted include investment security, reduced LCOE, increased energy access and diffusion of renewable energy technologies, particularly off-grid solutions, reduced grid instability, stabilized electricity prices, improved electricity diversity and economic development in the form of job creation [72]. This, however, can only be achieved with appropriate policy design supported by detailed fuel integration studies.

To increase the share of renewable energy sources in the country's energy mix and to improve power generation capacities in Nigeria, the ECN along with the UNDP have developed an NREEEP. This legislative framework will support the Renewable Energy Master Plan, a road map aimed at integrating renewable energy sources in existing electricity generation and distribution systems under short-, mid- and long-term goals. More so, the NERC, which is an independent regulatory body that standardizes the Nigerian electricity supply, has set a 10% renewable energy integration mix to encourage embedded generation and alleviate fossil fuel dependence. Therefore, the ongoing efforts to grow energy dedicated crops, such as *Jatropha curcas*, and subsequent production and use of the derived biodiesels in power generation, is expected to contribute to the 10% of the electricity required to be generated and sourced from renewable energy sources in Nigeria by 2025 [73]. In this instance, a limited period PBI support can be of benefit because it can ensure that a favourable environment is established for biodiesel fuel integration without resulting in an unnecessary economic burden for the country. This can reduce TLCC and ensure the adoption of biodiesel fuels in power plants.

3.4.2. Mandatory Renewable Energy Fuel Integration

Assuming a mandatory fuel integration process for new entrant power plants with renewable tax relief for the hours a plant operates on renewable fuels, Figure 4 shows that a minimum PBI support of 0.8 cents/kWh, 1.6 cents/kWh, 2.4 cents/kWh, 3.2 cents/kWh will be required for a 10%, 20%, 30%, and 40% partial fuel substitution (PFS) respectively with Jatropha biodiesel in the natural gas-FCP to ensure a comparative economic performance as the base-case scenario. Otherwise the LCOE of the plant can increase to \$0.090/kWh (10% PFS), \$0.103/kWh (20% PFS), \$0.115/kWh (30% PFS) and \$0.128/kWh (40% PFS), values that are beyond the current electricity contract price of \$0.077/kWh for gas power plants. For partial substitution in the natural gas-FOP, the plants will require a higher minimum PBI support of 1.3 cents/kWh, 2.5 cents/kWh, 3.8 cents/kWh, 5.0 cents/kWh for PFS of 10%, 20%, 30%, and 40% respectively for a comparative economic performance. In the absence of such support, the LCOE of the plant can be up to \$0.078/kWh, \$0.098/kWh, \$0.117/kWh and \$0.136/kWh respectively and the plant owners cannot recover the cost of investment. For the Jatropha biodiesel-fired plants to be as competitive as the gas-fired plants based on the 2016 NERC regulated price of \$0.113/kWh, partial Jatropha biodiesel fuel substitution must not exceed 33% for the Jatropha biodiesel-FOP and 40% for the Jatropha biodiesel-FCP. In both plant scenarios, partial substitution refers to a fraction of the plant operating hours on Jatropha biodiesel fuel, particularly aimed at periods when fossil fuel is unavailable.

Fig. 4: The LCOE of the natural gas-fired plants with mandatory fuel substitution

3.4.3. Carbon Tax

The use of renewable fuels and technologies has become one of the major precautionary measures for greenhouse gas (GHG) emission reduction. Worldwide, market based mechanisms such as carbon tax and emissions cap-and-trade systems are implemented to achieve national and regional emission reduction targets and to favour the investment, development and establishment of low carbon technologies, especially in power generation. To reduce social costs and to minimize negative burdens and influences on economic growth, employment and security, these mechanisms are usually supported or incentivized by other tax relief systems. In the electricity sector, carbon tax is established per ton of emissions and is increasingly applied across many countries [74-75], which in turn is based on fuel type and energy conversion technology. In Europe, carbon costs vary from €5-30/tCO_2 and are expected to increase beyond €50/tCO_2 [76]. Ellis *et al.* [77] showed that British Columbia introduced a carbon tax of \$10/tCO_2 eq. that progressively increased by an additional \$5/tCO_2 eq. every year from 2008 to 2012 for power plants operating on coal, diesel, gasoline, propane and fuel oil and this favoured the use of biofuels. Countries such as Chile, Japan, Norway, South Africa and Sweden have applied carbon tax (\$2-168/tCO_2eq.) to enhance the diffusion of renewable energy technologies [78].

Fig. 5: The LCOE of the natural gas-fired plants with carbon tax levy

In this study, the natural gas-, diesel- and Jatropha biodiesel-FOP emitted 169 tC/MWh, 230 tC/MWh and 235 tC/MWh, and the -FCP counterparts emitted 109 tC/MWh, 149 tC/MWh and 151 tC/MWh respectively. While the carbon emissions from the fossil-fired plants are considered as anthropogenic pollutants, those resulting from the combustion of Jatropha biodiesel fuels are from biogenic sources, hence can be considered as neutral. Assuming that the fossil-fired plant receives a carbon levy per ton of carbon emissions while the Jatropha biodiesel-fired plant receives none, Figure 5 shows that the LCOE for the NG-FOP can approach the NG-FCP at carbon cost of about \$100/tCO_2 (\$367/tC). Here, the LCOE of the NG-FOP and NG-FCP increases to \$0.114/kWh and \$0.115/kWh respectively, a corresponding 49% and 32% loss in a plant's economic performance. These can be accompanied by an increase in the SPB by one and two years, and decrease in B/C ratio to 1.58 and 1.09 for the NG-FOP and NG-FCP respectively. The NPV of these plants can also reduce to 2,672 million (NG-FOP) and 3,622 million (NG-FCP), a corresponding 23% and 34% reduction from the baseline values at the electricity generation price of \$0.113/kWh.

Although the natural gas-fired power plants were less competitive, the imposed carbon cost was not sufficient to make the Jatropha biodiesel-fired plants economically competitive as the natural gas plants. This is because the percentage contribution of individual costs (i.e. capital, fuel, maintenance and emission costs) for the power plants varies for the different fuels. At carbon cost of \$100/tCO_2, the emission costs cover 38%, 23% and 19% of the total costs for the CCGT, and 56%, 26% and 22% for the OCGT for natural gas, diesel and Jatropha biodiesel respectively. Fuel costs on the other hand have a meagre share (i.e. 2-3%) of the total annual costs of the natural gas plants, but a significant share of the liquid-fired plants, about 51%-65%. More so, there are growing environmental concerns on the production system of *Jatropha curcas,* that could significantly influence the carbon credit system of Jatropha biodiesel-fired plants. Some authors have reported a reduction in GHGs [79-80], while Ariza-Montobbio *et al.* [81] and Findlater and Kandlikar [82] showed that the use of biodiesels could increase GHG emissions. This is because the production system of *Jatropha curcas* and subsequent conversion of the oil to biodiesel requires the use of fossil fuels and nitrogen-based fertilizers that could significantly increase the environmental burden of the fuel. It is also anticipated that their cultivation could negatively impact on land and water use, as well as contribute to higher food prices and shortages in developing countries [82]. The crop was originally recommended to be grown on degraded or wasteland with minimal agricultural inputs [83] due to the crop's resilient abilities to adapt to poor soil and adverse climatic conditions. However, studies by Achten *et al.* [84], Ariza-Montobbio *et al.* [81] and Axelsson *et al.* [85] have shown that there is a significant cost on seed and oil yield. In this context, Jatropha biodiesel is considered to be a low carbon project and not a neutral carbon system. For energy and environmental balance, a seed yield of at least 2 tonnes per ha per year is recommended [79]. This can further be improved with the use of superior genetic seed strains, agricultural practices and soil conditions [79; 84]. Therefore, a complete environmental life cycle assessment will be required to support any carbon trading or credit system. High quality fuel production and conversion will be required to avoid any negative influence on plant performance. Fuel price will need to be competitive and renewable incentivized systems will need to be justified.

Based on the above considerations, an analysis of an incentive or carbon trading system, where the Jatropha biodiesel-fired plants receive equivalent credits of carbon costs from natural gas-fired plants, shows that the LCOE of the Jatropha biodiesel-fired plants can reduce significantly to \$0.185/kWh (NG-FOP) and \$0.159/kWh (NG-FCP) at a high carbon cost of \$100/tCO_2, a 36% and 27% reduction in LCOE. This ensures that the Jatropha biodiesel -FCP has a positive NPV at the end of the project with an SPB of 12 years and minimal B/C ratio of at least 0.35. In all the defined carbon tax scenarios, CCGT as more energy efficient engines were best suited and could be used competitively for utilizing Jatropha biodiesel fuel for power generation. For the diesel-fired plants, the LCOE of the plants exceed those of the Jatropha biodiesel-fired plants at a carbon cost above \$40/tCO_2 (\$147/tC).

3.4.4. Fuel Subsidy

Typically, fuel cost is a major fraction of operational cost, and could be as high as 83%, but this depends significantly on fuel consumption rate or plant's net efficiency and fuel market price. Figure 6 shows that the LCOE of the JT-FOP has a similar economic performance to the natural gas-FOP under a fuel market price of $0.5/gallon or less. This ensures that the plant is economically viable at the wholesale electricity selling price of $0.077/kWh. Above this value, the current electricity selling price for gas power plants can hinder the economic viability of Jatropha biodiesel-fired plants. A fuel price of $1.8/gallon also ensures that the LCOE of the JT-FOP is the same as the JT-FCP, more so, it is equal to the wholesale electricity selling price of $0.113/kWh. Beyond the fuel price of $1.8/gallon, the JT-FOP and -FCP cannot be as competitive as the natural gas plants; hence, a different wholesale electricity selling price would be required, perhaps at the wholesale electricity selling price for biomass power plants. At the electricity selling price of $0.232/kWh, the fuel price must not exceed $5/gallon for the JT-FOP and $8/gallon for the JT-FCP. Fuel subsidy as small as $0.2/gallon and as much as $5/gallon therefore can be issued nationally for the integration of Jatropha biodiesel fuel in power plants. The magnitude of benefits, however, depends on the cost of production of the fuel and the market price of alternate fuels.

Fig. 6: The LCOE of the Jatropha biodiesel-fired plants at varying fuel prices

4. Sensitivity Analysis

The economic analyses presented in this study are based on point estimates, which individually or collectively can affect the economic measures if different from the values presented in Table 4c. To determine the sensitivity of the different parameters (i.e. capital costs, WACC, depreciation rate, inflation rate, company tax rate, discount rate, CF, auxiliary components, fixed and variable maintenance costs) on the economic performance of the Jatropha biodiesel-fired plants, each of the parameters was individually varied by 20% while all others were kept constant. The results are presented in Figure 7 for JT-FOP and -FCP respectively.

Fig. 7: Sensitivity Analysis on LCOE of the Jatropha biodiesel-fired OCGT and CCGT

For both OCGT and CCGT engines, sensitivity values were similar, hence OCGT only is discussed. The results observed in Figure 7 show that capital cost, CF, company tax rate, discount rate and Pre-Tax Real WACC have a range of sensitivities between 4% and 18% in increasing order, while energy requirements for auxiliary components, inflation rate, depreciation rate and maintenance costs have minimal influences, i.e. values less than 1% for a ± 20% change in the base value. For instance, a Pre-Tax Real WACC of 11% has been used throughout the analysis following the estimate of the NERC [86]; however, this is an average value and varies from period to period. As such, the sensitivity analysis showed that the LCOE decreased by 16.3% for a 20% decrease and increased by 18% for a 20% increase in Pre-Tax Real WACC base values. Since Pre-Tax Real WACC is the actual costs incurred for the power plant via equity and debt, and prior to tax reduction, the results imply that there is a significant risk and reduced economic value of the power plant with the increase in Pre-Tax Real WACC value but a fair return rate on investment with the increased Pre-Tax Real WACC value. A 20% reduction in discount rate brought about a decrease in LCOE by 14.0%; this is because there is a corresponding increase in the present value of the net cash flow of the power plant. A reverse trend is observed with a 20% increase in the discount rate. Here the LCOE increased by 14.7% which increases the risk in the future cash flow of the power plant. The CF is the ratio of actual to potential output for a given period time. A value of 80% was allocated on the basis of baseload operation but this can change due to factors such as pipeline vandalizing, fuel unavailability, poor maintenance and other operating issues, resulting in increased downtime. It therefore reflects the annual operating hours of the power plant, and affects both fuel and maintenance costs. The sensitivity analysis shows that an increase in CF by 20% can bring about a reduction of 5.6% in LCOE but increases this by 3.7% for a 20% increase in the base value. Capital costs are reported in the range of \$800-1000/kWh for OCGT and \$1000-1250kWh for CCGT [87]. A value of \$978/kWh was adopted for OCGT based on NERC's recommendation and \$1476/kWh was assumed for the CCGT. These values include the costs for procurement, engineering and construction, planning and approval, technical services, land acquisition, infrastructure, water and effluent treatment, connection to transmission network, fuel handling and storage, i.e., the costs of procurement and installation, which vary and depend on site location, plant design and capabilities and other local factors, such as cost escalation and inflation. The sensitivity analysis shows that capital cost, company tax rate and inflation rate changed by 3.9%, 8.2% and 1.2% for a ± 20% change in the base value. Depreciation cost allocates part of the investment costs over the plant's useful life, hence had minimal influence; as such a ± 20% change in a depreciation rate only brought about 0.6% change. These results demonstrate that LCOE for these power plants can be reduced significantly by aiming at the reduction of the TLCC, mainly by improving a plant's CF and reducing discount rate, company tax rate, capital cost and Pre-Tax Real WACC.

This study determined the cost of SGE in comparison to the regulated wholesale electricity generation (contract) prices in Nigeria. It has considered various economic scenarios through which Jatropha biodiesel can be used for power generation in Nigeria using industrial gas turbines. The study has not considered the impact of feedstock security that might result from poor infrastructures, theft or competitive demands for oil. Further assessment would be required to examine the socio-economic impact of the Jatropha biodiesel-power generation in Nigeria.

5. CONCLUSION

The techno-economic performance of a Jatropha biodiesel-fired plant with open and combined cycle configurations was evaluated and compared to fossil-fired engines, using NPV, SPB and LCOE. Economic mechanisms of integrating Jatropha biodiesel were explored with the aim of operating the plant with a suitable alternative without compromising the plant's economic viability. The results show that Jatropha biodiesel can be substituted for natural gas in industrial gas turbines and for distributed or embedded power generation in Nigeria. The use of this fuel, however, comes at a cost of increased fuel consumption with slight loss in power (~2%) and plant efficiency (~1%). The exclusive use of Jatropha biodiesel in the OCGT and CCGT engines can bring about an LCOE of 0.279/kWh and $0.203/kWh respectively. These values exceed plants' projected revenue (i.e. electricity generation price of 0.081/kWh and 0.113/kWh for existing and new entrant plants respectively). At the electricity generation price for biomass power plants, only the Jatropha biodiesel-FCP is economically feasible and as competitive as gas power plants. Therefore, to integrate Jatropha biodiesel into power plants, a form of financial support would be required to ensure as competitive a plant performance as natural gas-fired plants. This could take the form of i) a minimum PBI of $0.082/kWh for seven years for the Jatropha biodiesel-FOP and $0.052/kWh for nine years for the Jatropha biodiesel-FCP, ii) a maximum PFS of 33% (Jatropha biodiesel-FOP) and 40% (Jatropha biodiesel-FCP) without any form of financial support, or iii) a guaranteed Jatropha biodiesel fuel price of $/0.18/gallon. Beyond this fuel price, a different wholesale electricity contract price would be required. These mechanisms can guarantee that the generator recovers the initial cost of capital and operating costs. A carbon tax levy can also be imposed on natural gas-fired plants, which nearly doubles the LCOE with a carbon tax of $100/tCO_2$. These carbon tax scenarios do not guarantee the economic viability of the Jatropha biodiesel-fired plant. A combination of all the above mechanisms could be exploited to improve the competitiveness of the Jatropha biodiesel-fired plants. In a worst case scenario, where there are no government incentives, there are opportunities for distributed and independent power generation using Jatropha biodiesel, since the average cost of electricity was as high as $0.45/kWh for the SME and 0.70/kWh for the household. The CCGT, as a more energy efficient engine, was best suited and could be used competitively for utilizing Jatropha biodiesel fuel for power generation.

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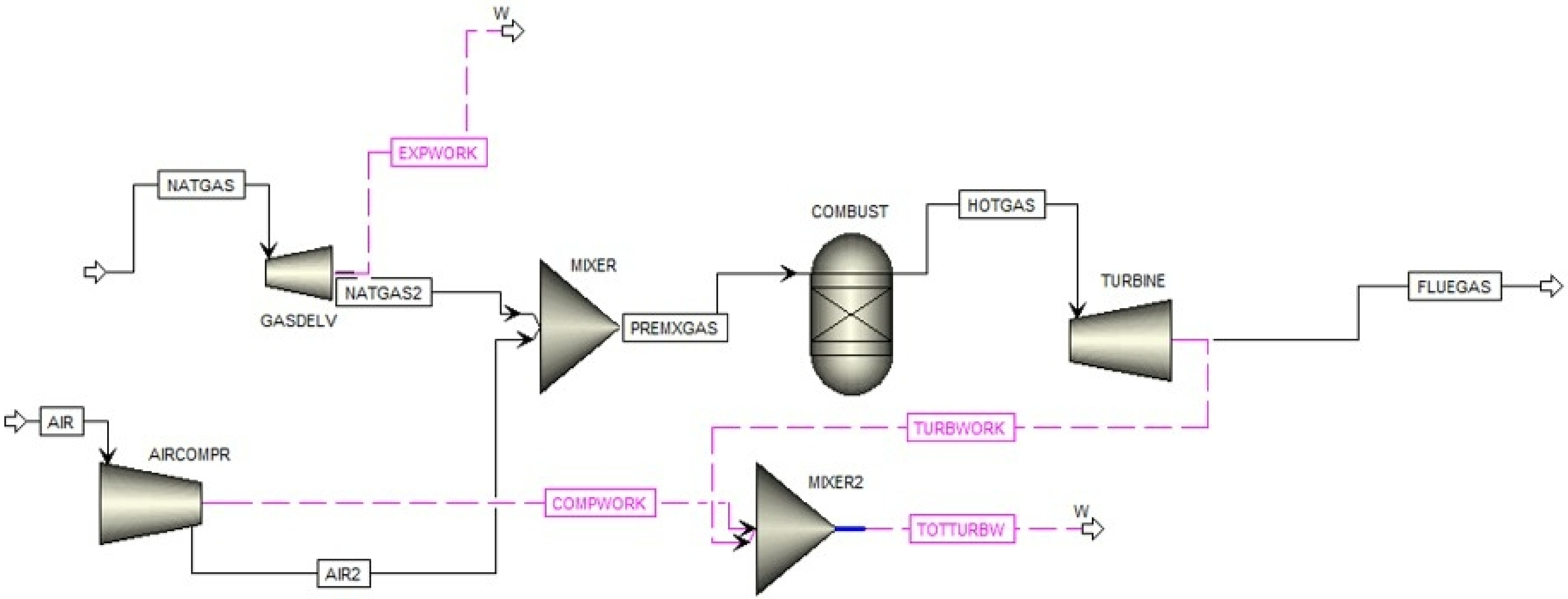

Figure 1: Simplified flow diagram of the open cycle gas turbine

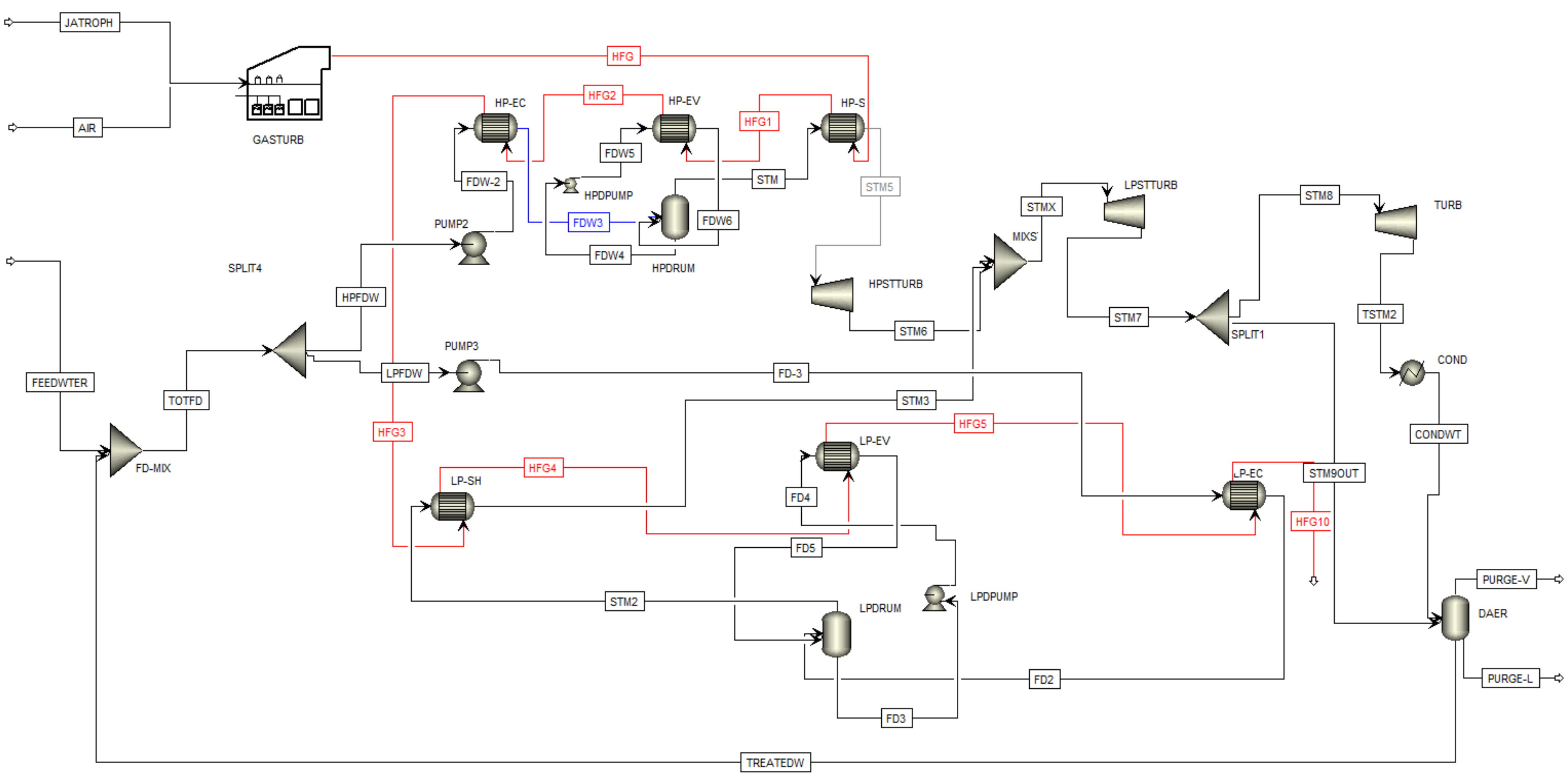

Figure 2: Simplified flow diagram of the combined cycle gas turbine

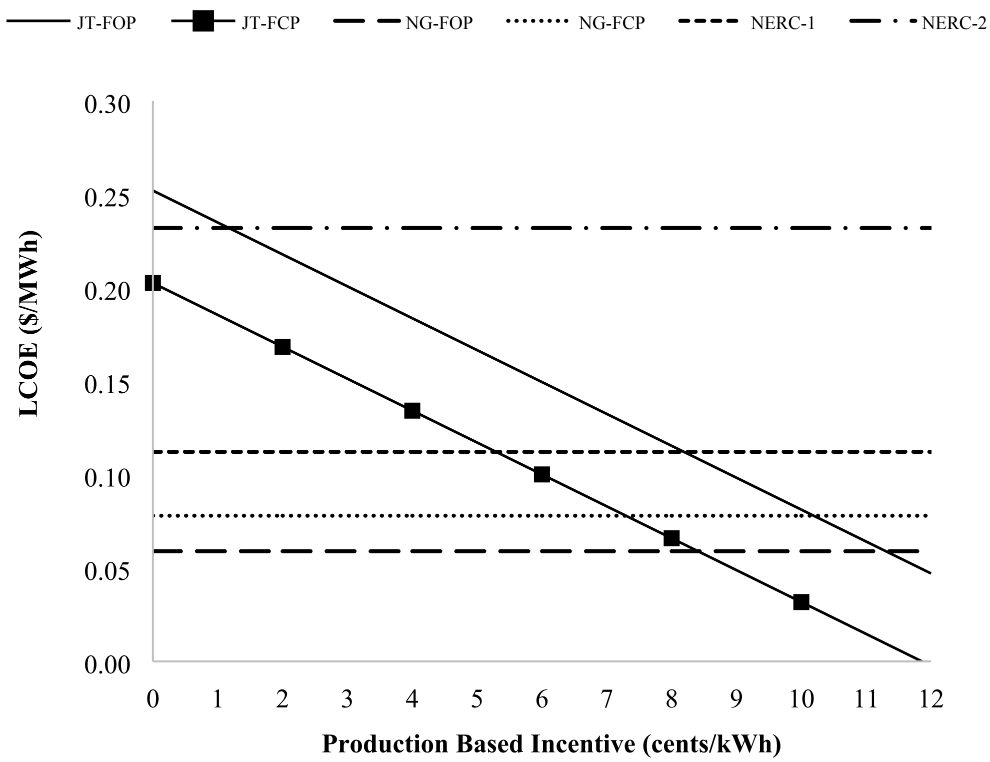

Fig. 3: The LCOE of the Jatropha biodiesel-fired plants with production-based incentive (PBI) support

JT -Jatropha Biodiesel; NG -Natural Gas; -FOP -Fired OCGT Plant; -FCP -Fired CCGT Plant; NERC-1 – Electricity generation price for 2016 new entrants gas power plants; NERC-2 – Electricity generation price for 2016 biomass power plants

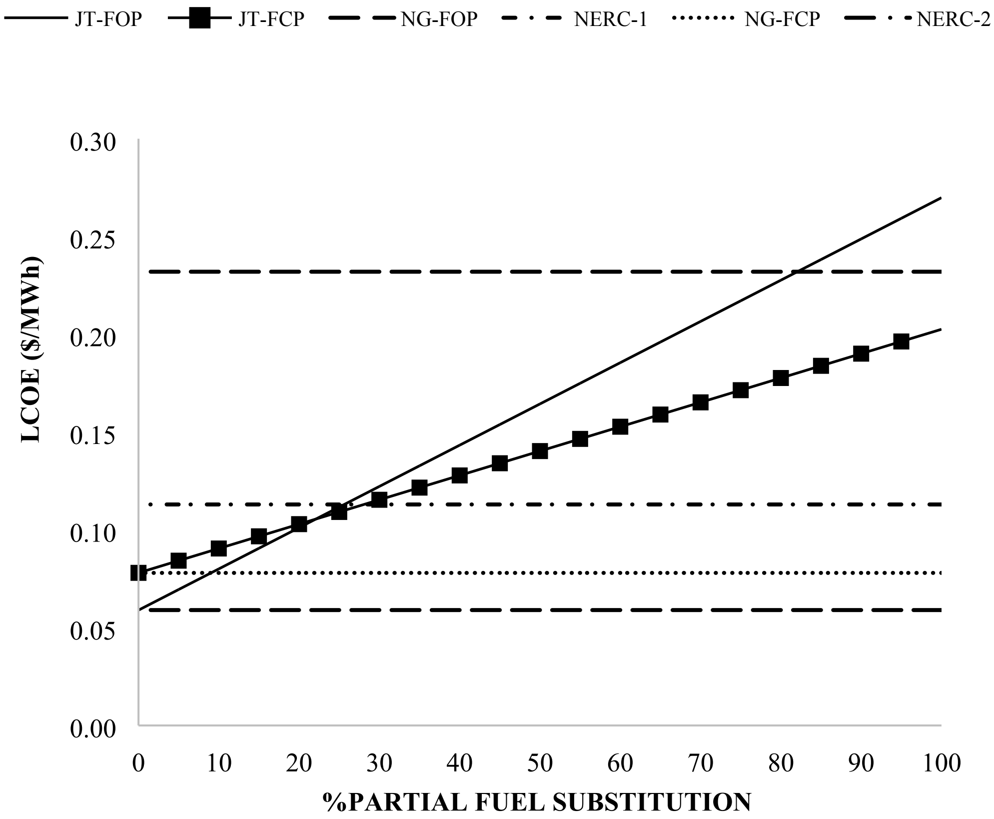

Fig. 4: The LCOE of the natural gas-fired plants with mandatory fuel substitution

JT -Jatropha Biodiesel; NG -Natural Gas; -FOP -Fired OCGT Plant; -FCP -Fired CCGT Plant; NERC-1 – Electricity generation price for 2016 new entrants gas power plants; NERC-2 – Electricity generation price for 2016 biomass power plants

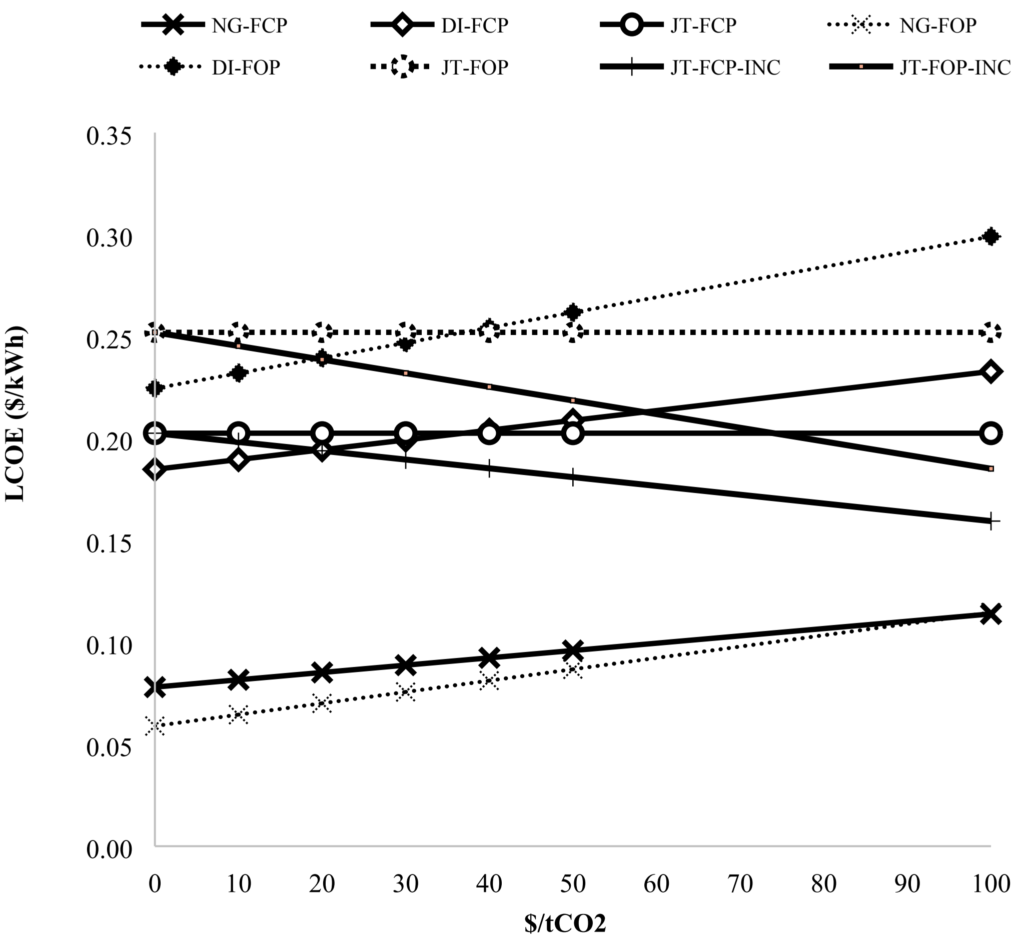

Fig. 5: The LCOE of the natural gas-fired plants with carbon tax levy

JT -Jatropha Biodiesel; NG -Natural Gas; -FOP -Fired OCGT Plant; -FCP -Fired CCGT Plant; INC-Incentivised

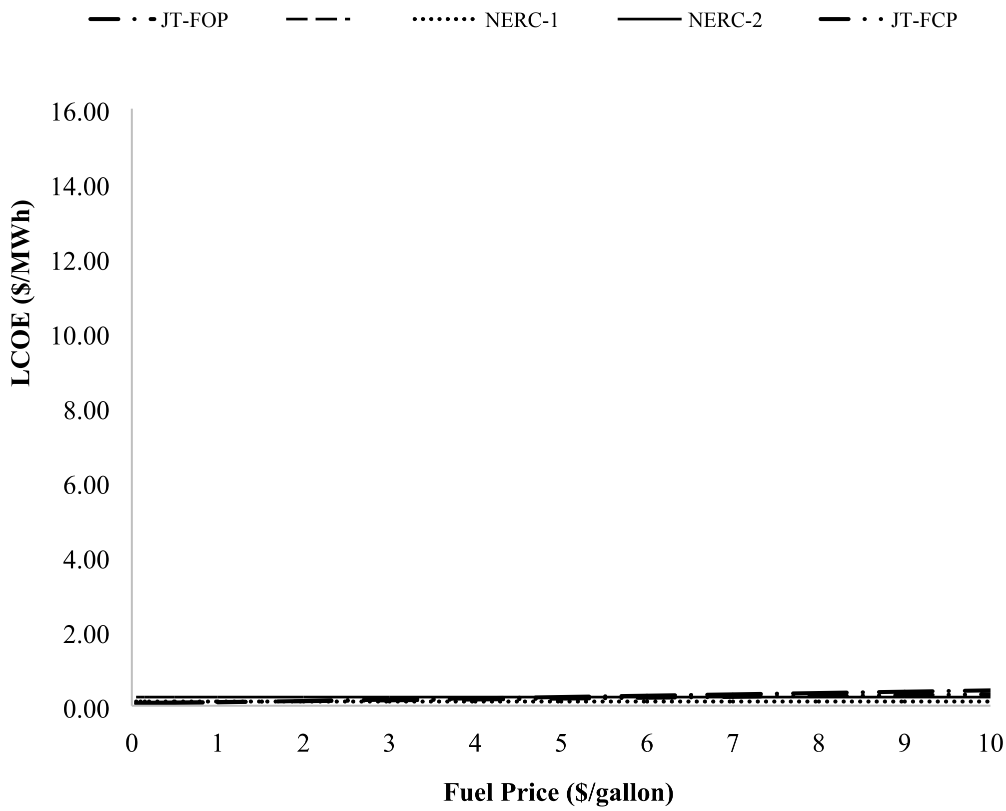

Fig. 6: The LCOE of the Jatropha biodiesel-fired plants at varying fuel prices

JT -Jatropha Biodiesel; -FOP -Fired OCGT Plant; -FCP -Fired CCGT Plant; NERC-1 – Electricity generation price for 2016 new entrants gas power plants; NERC-2 – Electricity generation price for 2016 biomass power plants

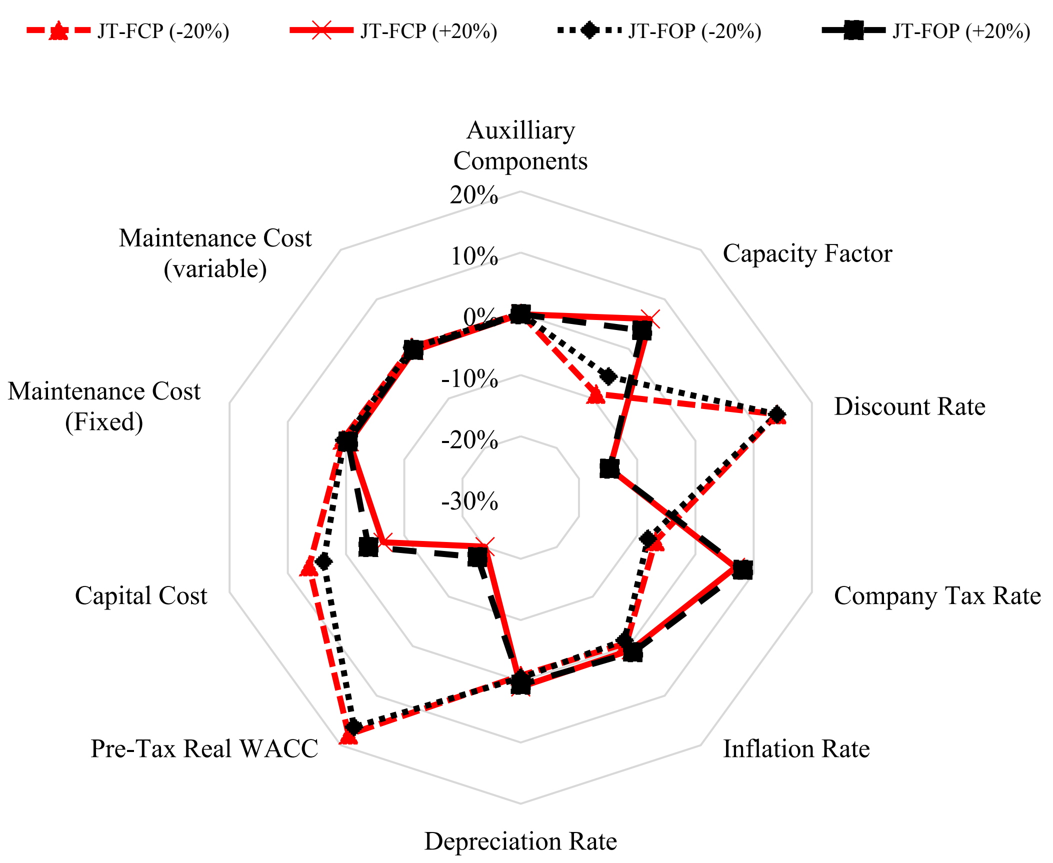

Fig. 7: Sensitivity Analysis on LCOE of the Jatropha biodiesel-fired plants

JT -Jatropha Biodiesel; NG -Natural Gas; -FOP -Fired OCGT Plant; -FCP -Fired CCGT Plant

Highlights

- Feasibility of Jatropha biodiesel for power generation in Nigeria was investigated.
- Application in gas turbines results in ~1-2% loss in plant output and efficiency.
- The LCOE varied from $0.203-0.252/kWh, depending on mode of operation.
- The full cost of self-generated electricity in Nigeria is valued at $0.45-0.70/kWh.
- Residents can lower annual energy cost by 71% with Jatropha biodiesel-fired plants.

Table 1: Input data and model assumptions for the OCGT/Topping cycle

Block Name	Block Parameters & Assumptions
AIRCOMPR (Compressor)	P = 1.013 Bar; T = 15^{o}C; Compressor Isentropic Efficiency = 88%; Pressure Ratio = 12.6; Inlet Mass Flow = 418 kg/s
COMBUST (Combustor)	Combustor Pressure Loss = 5%; Chemical and phase equilibrium calculation; Maximum Combustor Outlet Temperature = 1083^{o}C
TURBINE (Turbine)	Turbine Isentropic Efficiency = 90%; Discharge Pressure = 1.14 Bar

Table 2: Input data and model assumptions for the Bottoming cycle

Block Name	Block Parameters & Assumptions
HP/LP SH (Superheater)	Hot Inlet-Cold Outlet minimum temperature difference = 20°C
HP/LP EC (Economiser)	Cold Outlet Stream Vapor Fraction = 0 (Saturated Liquid)
HP/LV EV (Evaporator)	Cold Outlet Stream Vapor Fraction = 0.5
HPDRUM (Drum)	Discharge Pressure = 80 Bar
LP DRUM (Drum)	Discharge Pressure = 10 Bar
Pump	Pump Efficiency = 80%; Driver Efficiency = 95%
DAER	Inlet Feed Water Temperature = 32.88°C; P = 0.05 Bar
COND	Condenser Pressure = 0.05 Bar
HP/IP/LP STTURB (Steam Turbine)	HP Discharge Pressure = 10 Bar; IP Discharge Pressure = 2 Bar; LP Discharge Pressure = 0.05 Bar; HP Steam Turbine Isentropic Efficiency = 90%; IP Steam Turbine Isentropic Efficiency = 92%; LP Steam Turbine Isentropic Efficiency = 94%; Mechanical Efficiency = 98%; Max. Steam Turbine Inlet Temperature = 560 °C; Minimum approach temperature in economizers, evaporators and superheaters = 5°C; Minimum Steam Quality =88%; Pressure loss in hot and cold side of the heat exchangers are negligible; Minimum Allowable Stack Temperature = 100 °C

Table 3: Parameters/Properties for the different fuels

Air	Mass fraction (%)	Natural Gas	Mass fraction (%)	Diesel	Mass fraction (%)	Jatropha Biodiesel	Mass fraction (%)
N_2	0.75550	CH_4	0.910	H_2O	0.00006	JB1- $C_{12}H_{24}O_2$	0.0451
O_2	0.23160	C_2H_6	0.060	PC87C	0.00001	JB2- $C_{14}H_{28}O_2$	0.0235
AR	0.01240	C_3H_8	0.015	PC101C	0.00002	JB3- $C_{16}H_{32}O_2$	0.1224
CO	0.00000	N_2	0.008	PC115C	0.00007	JB4- $C_{18}H_{36}O_2$	0.0663
CO_2	0.00050	O_2	0.000	PC128C	0.00022	JB5- $C_{18}H_{34}O_2$	0.2351
H_2O	0.00000	AR	0.007	PC142C	0.00044	JB6- $C_{18}H_{32}O_2$	0.5076
				PC156C	0.00073		
				PC170C	0.00141		
				PC184C	0.00273		
				PC198C	0.00528		
				PC212C	0.01141		
				PC225C	0.02528		
				PC239C	0.04842		
				PC253C	0.09122		
				PC267C	0.13514		
				PC281C	0.14483		
				PC295C	0.13421		
				PC309C	0.12056		
				PC322C	0.10539		
				PC336C	0.08402		
				PC350C	0.05418		
				PC364C	0.02486		
				PC378C	0.00749		
				PC392C	0.00163		
				PC406C	0.00033		
				PC419C	0.00006		

Table 4: Input in the Economic Model (Base-case)

Parameters	
Plant Life	20 Years
Output Losses	Auxiliary Components -2%; Transmission Losses -11%; Capacity Factor -80%; Capacity Degradation -2%
Economic Rates	Company Tax Rate-32%; Escalation Rate-11%; Depreciation Rate-5%; Exchange Rate-161 (₦-$); Pre-Tax Real WACC-11%; Discount rate-11%
Cost factor (OCGT)	Capital Cost -$978.5/MWh; Fixed Maintenance Factor -$15503/MW/Yr; Variable Maintenance Factor-$5.6/MWh; Emission Cost -$0/tCO_2
Cost factor (CCGT)	Capital Cost -$1370/MWh; Fixed Maintenance Factor -$21704/MW/Yr; Variable Maintenance Factor-$7.9/MWh; Emission Cost -$0/tCO_2
Fuel Price	Natural Gas -$2.8/MMBTU; Jatropha Biodiesel -$5.5/gallon; Diesel -$5.5/gallon
Fuel LHV	Natural Gas -49.07 MJ/kg; Jatropha Biodiesel -36.58 MJ/kg; Diesel -42.58 MJ/kg
Data (SME)	Engine rating -80&100 kVA (Perkins 1100 Series/Duetz); Operating hours -10 hrs/day; Power factor -80%; Purchase Cost – (0.0272/kWh); Fuel Cost -0.0766/kWh: Maintenance Cost -0.0053/kWh
Data (Household)	Engine rating -22 kVA; Operating hours -6 hrs/day; Power factor -80%; Purchase Cost – (0.1603/kWh); Fuel Cost -0.3519/kWh: Maintenance Cost -0.0348/kWh

Table 5: Engine Validation of the Natural Gas OCGT and CCGT engines at ISO Conditions

Parameters	PG9171E (MS9001 E)	NG*	Error
OCGT (1 Gas Turbine)			
Output (MW)	126.1	126.8	+0.52%
Heat Rate (kJ/kWh)	10653	10750	+0.91%
Mass Flow (kg/s)	418	419	+0.24%
Exhaust Temperature (°C)	543	545	+0.37%
Thermal Efficiency (%)	34.1	33.5	-1.79%
CCGT (2 Gas Turbines – 1 Steam Turbine)			
Output	391.4	382.5	-2.27%
Heat Rate	6840	7121	+4.01%
Net Plant Efficiency	52.7	50.6	-3.98%

* LHV of Natural gas – 49.07 MJ/kg

Table 6: Technical Analysis of the OCGT and CCGT engines (different fuels) at Site Conditions

Parameters	NG	DI	JT
OCGT (4 Gas Turbines)			
Total Output (MW)	468.8	456.1	460.4
Heat Rate (kJ/kWh)	11066	11283	11172
Thermal Efficiency (%)	32.5	31.9	32.2
Fuel Flow	14.68	16.79	19.53
CCGT (4 Gas Turbines – 2 Steam Turbines)			
Output	726.8	712.1	716.4
Heat Rate	7138	7228	7180
Net Plant Efficiency	50.4	49.8	50.1

Table 7: Economic Analysis of the OCGT and CCGT engines (different fuels) at Site Conditions

Parameters	NG	DI	JT
OCGT (4 Gas Turbines)			
LCOE ($/MWh)	0.059	0.225	0.252
SPB (Years)	5	>20	>20
NPV ($'million)	3295	-761	-1614
Benefit-to-Cost Ratio (B/C)	4.45	0	0
CCGT (4 Gas Turbines – 2 Steam Turbines)			
LCOE ($/MWh)	0.078	0.185	0.203
SPB (Years)	7	16	20
NPV ($'million)	4868	1039	439
Benefit-to-Cost Ratio (B/C)	3.42	0.15	0.06

Table 8: The Average Cost of Self-Generated Electricity in Nigeria

Parameters		SME	Household
Self-generated Electricity for a 24-hr period	\$/kWh	0.45	0.70
Self-generated Electricity for a defined period*	\$/kWh	0.19	0.46

*self-generated electricity for a period and black-out for the rest of the day.