

Article

Monetising Nigeria's Flared Gas: A Site-Specific Financial Analysis of Three Utilisation Pathways Across Three Flare Sites

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Abstract

This study provides a site-specific, unlevered financial screening of gas-to-power, gas-to-pipeline, and gas-to-compressed-natural-gas (CNG) options at three Nigerian flare sites: Amukpe (1.16 MMscf/d), Oziengbe South (5.15 MMscf/d), and Oben (10.88 MMscf/d). The cases are evaluated from the perspective of an independent third-party developer using discounted cash-flow analysis. The base case results show that gas-to-power produces NPVs of –US\$7.68 million, –US\$17.30 million, and US\$18.28 million at Amukpe, Oziengbe South, and Oben, respectively. Gas-to-pipeline produces –US\$0.72 million, US\$2.75 million, and US\$7.32 million, while gas-to-CNG produces –US\$3.97 million, US\$7.20 million, and US\$21.62 million. These results are conditional on the stated technical, commercial, and infrastructure assumptions because the analysis is equity-financed and excludes debt sizing, debt-service coverage, lender covenants, and contractual due diligence. This study therefore establishes a transparent comparison of three monetisation pathways under Nigeria's third-party flare-commercialisation framework. Thus, investment and/or policy decisions must be made only with a clear identification of the required site data.

Keywords: gas flare utilisation; energy conservation; financial modelling

1. Introduction

The decision to consider investing funds in gas flare and methane reduction projects, as with every other investment decision, depends on the project's ability to generate acceptable financial returns throughout its economic life. Financial indicators such as the net present value (NPV) and internal rate of return (IRR) are widely used as preliminary measures of economic attractiveness. However, although these indicators provide valuable evidence of economic viability, they do not by themselves establish project bankability. A financially attractive project may still fail to secure financing where uncertainties relating to gas supply, product offtake, infrastructure access, contractual arrangements, foreign exchange exposure, construction risk, or regulatory enforcement remain unresolved. Consequently, investment decisions for flare gas projects require consideration of both financial performance and the wider technical, commercial, and institutional environment in which the project operates.

Gas flare utilisation presents several technology pathways, each requiring different levels of investment and exhibiting distinct technical and commercial characteristics. Alternatives that can be implemented either on-site or following transportation include gas-to-power, liquefied natural gas (LNG), compressed natural gas (CNG), micro gas-to-liquid (GTL) plants, gas delivery through existing pipeline infrastructure, and gas hydrate conversion. Ojijiagwo et al. [1] and Adekomaya et al. [2] argue that using associated gas



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for electricity generation can be economically attractive, particularly in locations with large flare volumes or where multiple flares are situated close enough to justify investment in gas-gathering infrastructure. However, this option may be a less viable economic choice in offshore locations or in areas where flares are widely dispersed, as the absence of economies of scale and the high cost of constructing offshore gathering systems can significantly reduce feasibility. Similarly, pipeline delivery requires technically compatible and accessible transmission infrastructure, while CNG projects depend on adequate road access, transportation logistics, fleet availability, and sufficient downstream market demand. Consequently, flare volume alone is insufficient to determine the most appropriate utilisation technology or the expected financial return.

There is increasing acceptance of GTL technologies as a viable option for monetising flared gas. GTL tends to be most viable where sufficient gas volumes are available to support economies of scale, where stable markets exist for GTL products such as diesel or naphtha, and where favourable financing conditions and access to proven conversion technologies reduce project risk. As with other technologies, its deployment is challenging because of the high CAPEX requirements. In some instances, supply pipelines must be constructed from the flare point to the GTL facility, further compounding CAPEX. However, when completed, proceeds from derived products can be sold directly to the market or blended with crude products, thereby increasing the prospect of rapid return on investment [3]. Irrespective of whether gas is converted into electricity, transported through existing pipeline systems, processed into CNG or LNG, or utilised through other commercial pathways, the financial assessment must reflect the specific technical, logistical, and market characteristics associated with the selected technology [4].

For newly developed oil fields, flare gas utilisation projects may be incorporated into the overall field development plan. In contrast, for producing fields, operators must decide whether investment in flare reduction projects is justified by prevailing regulatory requirements and expected financial returns. Nigeria's Gas Flare Commercialisation Programme (NGFCP) introduces a distinct commercial framework by permitting flare gas to be allocated to independent third-party developers rather than being utilised exclusively by upstream operators. Under this arrangement, the project developer must obtain the flare gas under commercial terms, finance gas treatment and utilisation facilities, negotiate access to the operator's infrastructure where necessary, and secure reliable markets for the final products. While this framework creates new commercial opportunities for independent investors, project success continues to depend upon site-specific technical conditions, infrastructure availability, contractual arrangements, market access, and financing considerations.

Studies have examined gas flare utilisation technologies under different technical and economic scenarios. For example, Anomohanran [5] evaluated the Bonny LNG project and reported an average annual reduction in gas flaring of approximately 10.5% between 1999 and 2012, recommending continued implementation of similar projects. Ahmed et al. [3] demonstrated the successful application of GTL technology through the NNPC–Chevron Joint Venture, highlighting its commercial potential within Nigeria. Similarly, Ibitoye [6] modelled major gas utilisation projects in Nigeria and concluded that although existing projects had reduced flaring, additional investments would be required to achieve full gas utilisation.

Mansoor and Tahir [7] reviewed contemporary flare utilisation technologies and compared their advantages and limitations, concluding that LNG and CNG offer significant benefits because of their scalability and operational flexibility. Collectively, these studies demonstrate the technical feasibility of flare monetisation and provide valuable insights into individual utilisation technologies. Despite these contributions, important gaps remain in the literature. Existing studies have generally focused on comparing technologies,

evaluating individual projects, or developing decision-support tools, often from the perspective of upstream operators [4]. Furthermore, their findings are frequently difficult to transfer across locations because project economics depend heavily on gas composition, flare volume, infrastructure accessibility, distance to markets, fiscal conditions, financing assumptions, and contractual arrangements [8]. Consequently, no single financial model can be regarded as universally applicable across different flare sites. This limitation is particularly relevant within the NGFCP framework, where independent project developers, rather than field operators, bear responsibility for acquiring gas, financing infrastructure, and commercialising the recovered resource.

Against this background, this study develops transparent discounted cash flow models to evaluate three gas utilisation pathways across three identified Nigerian flare sites from the perspective of an independent third-party developer. The study's contribution lies in applying a consistent third-party developer framework to site-specific projects while making explicit the assumptions that determine the resulting financial performance. Accordingly, the analysis is interpreted as an economic screening exercise rather than a demonstration of full project bankability, recognising that additional engineering, environmental, contractual, market, and financing assessments would be required before any final investment decision could be made.

2. Literature Review

Various recommendations have been offered to tackle the menace of gas flaring from policy perspectives, through regulations, market structures, and monetisation options [9,10]. Dong et al. [9] conducted a comparative techno-economic analysis of the deployment of GTL or LNG technologies for the monetisation of stranded gas. This paper pointed out that LNG technology has over 40 years of maturation and safety records. GTL technology is also promising, but with much higher capital costs compared to LNG. It was discovered that the GTL facility has lower plant efficiency and is more expensive than LNG. However, it serves different energy markets with a slightly higher value per MMBTU than that of LNG. The study concludes that GTL is starting to show some viability potential and is likely to expand its share in the energy market. In a study on Bonny LNG by Anomohanran [5], the flare reduction rate achieved by the project from 1999 to 2012 was computed. The results show a yearly decline in the rate of flaring activities of 10.5%. Owing to the significance of the project's impact on flare gas reduction, recommendations for the continuous implementation of similar projects have been made. The success of the gas-to-liquid project by the NNPC–Chevron joint venture (JV), as highlighted by Ahmed et al. [3], indicates the viability of GTL technology in Nigeria and encouraged the nation to pursue similar activities in utilising its abundant gas resources and reduce flaring. A similar case of the high cost of GTL for gas flare utilisation was re-echoed by Rahimpour et al. [11], who simulated the design of three flare gas utilisation technologies using the steady-state process simulation software and applied the same to the gas being flared in Asalooye refinery. The simulated technologies were gas-to-liquid (GTL), gas-to-electricity, and compressed gas for injection into refinery pipelines. At the end of the study, GTL was found to have the greatest rate of return but the highest capital investment. Gas compressed into pipelines is the second most profitable and is therefore recommended for implementation at the Asalooye refinery.

Similarly, Ibitoye [6] considered major projects targeting gas utilisation commissioned in Nigeria and how these projects assist in reducing the volume of gas being flared. The volumes to be absorbed by the planned projects and new projects were simulated using computer programming. Overall, the existing and planned projects failed to remove the total volume being flared. Only further investments in new projects were found to remove

current volumes. Recommendations for further investment in new gas flare reduction projects are also proposed.

The application of CNG technology in the transport sector was modelled by Otene et al. [12] to measure their potential for reducing carbon dioxide emissions in the city. The study found a proportional relationship between the usage of CNG as a transport fuel and the reduction in CO₂ emissions in Lagos. Recommendations for the economic analysis of flare capture and conversion to CNG were made thereafter. Targeting the power sector, Ojijiogwo et al. [1] modelled the investment requirements necessary for the conversion of flare gas to electricity. To ensure the sustainability of the venture, strict government monitoring of the modelled project was recommended, while suggesting the promulgation of laws that could encourage the provision of subsidies to investors interested in the development of gas-to-electricity projects.

In a separate review by Mansoor and Tahir [7] targeting the reformation of gas flares to efficient fuels, LNG and CNG were found to be the most viable methods based on their applicability, commerciality, and economic potential. As a result, these technologies are recommended for adoption, with further improvements in the utilisation of flared gas for efficient energy fuels. Putriastuti et al. [13] used financial indicators such as the internal rate of return, the net present value, and the payback time to assess the economic feasibility of small-scale LNG as a flare utilization technology in Indonesia. The results of the base case scenario show that the project is not feasible. Adjustment of the LNG selling price to a minimum of \$6/MMBTU, a CAPEX reduction of about \$6000, and a flare gas price of less than \$0.5/MMBTU are required to make the project profitable. The authors recommended comparing these findings with CNG technology in future research as well as improving the logistics between sellers and buyers to reduce OPEX due to transportation.

While Rahimpour et al. [11] considered only three technologies, Tahmasebzadehbaie and Sayyaadi [14] assessed various combinations of eleven gas flare recovery technologies with their corresponding downstream reliability on an oil well in Iran. The assessment included technical, economic, and environmental considerations. The best technology was selected using the TOPSIS decision-making method, whereas the technologies and environmental aspects were modelled using MATLAB. The selected technology's payback period was found to be 1.12 years while carbon dioxide was reduced by 1.3 million tons during the period under consideration. Along these lines, Lorenzato et al. [4] provided a guide for constructing financial models of flare projects from third-party perspectives to enable developers to adopt the same in modelling their projects considering the specifications of the project at hand, as well as the characteristics and volume of gas available at the flare. Data from real-life executed gas flare projects around the world were used as the basis for the determination of capital and operational expenditures for the developed models.

While Dong et al. [9] use the net back pricing method to conduct an economic analysis, Rahimpour et al. [11], Ibitoye [6], and Anomohanran [5] use the rate of return capacity increment, natural gas accounting model on spreadsheets, and descriptive analysis to arrive at the best technology. These studies are all indicative only, as no specific values outlining the profitability of the selected technologies were issued. Otene et al. [12] and Ojijiagwo et al. [1] both employ the use of commercial software. The latter employs long-range energy alternative planning (LEAP) modelling software to arrive at his conclusion, while the former uses NVIVO software to analyse data collected through semi-structured interviews. Other notable methods include the comparison of various technologies based on their CAPEX, OPEX, space requirements for infrastructure construction, the complexity of the technologies, and their commercial experience in the field. Since the aim of this work is to provide an evidence-based assessment using operational data obtained from oil and gas operators in Nigeria, such as gas flare volumes and locations, along with

flare gas sale price and electricity tariff costs, the internal rate of return and net present value indicators would be used in this case as applied by Putriastuti et al. [13], Tahmasebzadehbaie and Sayyaadi [14], and Lorenzato et al. [4]. Following the conceptualisation of Mugodzva et al. [15], Table 1 systematically compares the present study with the most closely related techno-economic analyses.

Table 1. Comparison with closely related flare-utilisation studies.

Study	Setting and Technologies	Developer/Finance Perspective	Site Specificity	Uncertainty Treatment	Limitation Relative to This Study
[4]	Global flare projects and financing solutions	Third-party developer/financing	Framework and case evidence	Risk-factor analysis	Not a cross-technology assessment of named Nigerian sites
[9]	Stranded gas; LNG versus GTL	Project economics	Generic/technology comparison	Deterministic	Not specific to Nigeria, no third-party flare allocation
[11]	Asalooye refinery; GTL, power, pipeline injection	Operator/project	Single refinery	Deterministic	Different market, gas quality, and infrastructure context
[13]	Indonesia, small-scale LNG	Project feasibility	Single regional case	Scenario/break-even	Single technology; different logistics and fiscal setting
[14]	Iran; multiple recovery technologies	Integrated techno-economic assessment	Single well/case study	Multi-criteria/reliability	Not third-party commercial structure
[16]	Nigeria; LNG, methanol, gas-to-wire decision tool	Operator/investor decision support	Two fields	Techno-economic regulatory screening	Different technologies and model architecture
This study	Named Nigerian flare sites	Unlevered third-party developer	Three named sites	Deterministic screening	Public-data pre-feasibility; no debt contracts or site surveys

Although these studies have attempted to simulate the economics of gas flare utilisation technologies in different contexts, their recommendations cannot be applied with any level of certainty to other flare sites in different regions. Accordingly, the study cannot isolate a causal “scale effect” from other site attributes. The results should be read as nine conditional site–technology cases.

3. Materials and Methods

3.1. Research Design, Case Selection, and Scope

The study adopts a comparative case-study design. The unit of analysis is a site–technology combination rather than flare-size class. Information on the gas flaring location, volume, and composition is critical to stakeholders interested in designing measures to deal with the situation. Traditionally, this information is provided mostly by operators or third-party stakeholders, with no direct means of quantifying such measurements because of the failure to install appropriate measuring instruments. Owing to recent global awareness of the effects of gas flaring and the need to track both new flares and monitor the volume and composition of existing ones, remote sensing is gradually becoming an emerging trend [17].

Satellite imagery has been used to detect gas flaring, with the largest collection of flare imagery registered by the U.S. Air Force Defense Meteorological Satellite Program (DMSP) using the Operational Line-scan System (OLS). Similarly, nighttime thermal imagery from a moderate-resolution imaging spectroradiometer (MODIS) using the Landsat Flare Detection Method (LFDM) was employed to detect and estimate flare gas in Nigeria [18]. A Robust

Satellite Technique based on the MODIS method was also adopted for mapping flares in the Niger Delta as well as sites in Italy. A comparison of the estimated flared volumes obtained from the regression models based on MODIS and data obtained from operators indicated a high level of precision.

Based on the above-mentioned techniques, the World Bank, through the Global Gas Flaring Reduction Partnership, provided interactive satellite imagery of flare sites around the world containing the specific locations of such sites, as well as their estimated volumes and heat content [19]. The World Bank's satellite data provide location and estimated flare volume only; other inputs required for a bankable feasibility study, including measured gas composition, pressure, flow variability, remaining field life, route distance to infrastructure, land access, road condition, operator tie-in requirements, or binding offtake terms were not readily available. Adopting this classification, three flare sites were selected based on grouping by the Global Gas Flaring Reduction (GGFR) partnership of large, medium, and small flares. Large flares are those with estimated volumes of about 10 MMscf/d (million standard cubic feet per day) and above, medium flares are between 5 to 9 MMscf/d, and small flares are those with approximately 1 MMscf/d. The labels "small", "medium", and "large" are retained only as descriptive World Bank volume categories; they are not treated as statistically representative strata.

The selected large flare site was in the Oben oil field, situated in OML 4 at a latitude of 6.014 and longitude of 5.865 [19]. OML 4 is the main operating field within that block containing a 60,000 bopd capacity flow station, a non-associated gas processing capacity of 465 MMscf/d, and five (5) 10 MMscf/d-associated gas compressors. The Oben field is Seplat's central site, which holds the company's future gas expansion plans and is strategically located as an important gas hub with access to Nigeria's main gas demand centres [19]. The estimated flared volume was 3955 MMm³, which translates to approximately 10.88 MMscf/d. Similarly, the medium site was chosen from the same filter with an estimated flare volume of 5.15 MMscf/d and located in the Oziengbe South oil field with latitudes and longitudes of 6.065 and 5.437, respectively. The field is operated by Sahara Energy. The Amukpe oilfield represents a small flare site with an estimated flare volume of 1.16 MMscf/d. the field is located at latitude 5.862 and longitude 5.69, which covers an area of 2094 km² approximately 48 km north of the historic city of Warri, Delta state. The field is operated by Seplat Energy on OML 38, which includes Amukpe, Okpohuru, Orogho, and Avhor. Facilities on the block include a 45,000 bpd capacity flow station, a liquid treatment facility and two (2) 50,000 bbls crude storage tanks located at Amukpe [19]. Table 2 summarises the observed and assumed case attributes. The flare-volume estimates are the principal observed sizing variables. It should be noted that infrastructure proximity and market access remain screening assumptions only.

Table 2. Case-site characteristics and evidence boundaries.

Case Site	Operator/Field Context	Estimated Flare Volume (MMscf/d)	Role in This Study	Important Unverified Variables
Amukpe	OML 38; Seplat-operated field facilities	1.16	Low-volume case	Gas composition and pressure; tie-in distance; grid/pipeline access; road and customer data
Oziengbe South	Sahara Energy-operated field	5.15	Intermediate-volume case	Remaining supply profile; infrastructure route; offtake and payment terms; road logistics
Oben	OML 4 gas hub with existing processing infra-structure	10.88	Higher-volume case	Incremental tie-in capacity; contractual access; curtailment; product market terms

3.2. Financial Model Architecture and Decision Criteria

This section evaluates the financial performance of gas-to-power, gas-to-pipeline, and gas-to-CNG systems based on the available gas flare volume from the three selected sites using discounted cash-flow models. Although other technologies can be employed in utilizing gas at the flare, we decided to model the three as they have a track record of being deployed in the industry [7] and costs data are accessible as compared against other technologies. For example, natural gas hydrates formation technology from flared gas is in its infancy stage [19] while GTL is characterized by high capital costs and lack of access to the technology by small midstream players willing to enter the flared gas utilization space [19]. LNG projects where guaranteed gas supply is not ensured (as in the case of flare gas) were found to be non-viable [13]. The model is an unlevered, pre-tax discounted cash-flow screening from the perspective of a third-party developer. Initial investment is recognised explicitly at time zero (Equation (1)). Annual free cash flow is calculated from technology-specific revenue less gas acquisition cost, cash operating expenditure, sustaining capital expenditure, changes in networking capital, and tax (Equation (2)). The general model is:

$$NPV = -I_0 + \sum_{t=1..N} [FCF_t / (1+r)^t] + [(RV_n - DC_n) / (1+r)^N] \quad (1)$$

$$FCF_t = R_t - C_{gas,t} - OPEX_t - SCAPEX_t - \Delta NWC_t - Tax_t \quad (2)$$

where I_0 is the time-zero installed investment; R_t is technology-specific revenue; $C_{gas,t}$ is flare-gas acquisition cost; $OPEX_t$ is cash operating cost; $SCAPEX_t$ is sustaining capital expenditure; ΔNWC_t is the annual change in net working capital; RV_n is terminal residual value; DC_n is decommissioning cost; r is the discount rate; and N is project life. IRR is the discount rate that sets Equation (1) equal to zero. In the reported base cases, ΔNWC , residual value, and decommissioning cost are set to zero and are disclosed as simplifications. A zero residual value is conservative, whereas zero decommissioning cost is optimistic.

3.3. General Assumptions, Price Base and Financing Conventions

This section highlights the general assumptions that are applicable to all projects modelled in this study. Base case scenarios are developed based on publicly available information, and the development of flare projects is considered from a third-party perspective, as opposed to development by the producer, which was the norm. This is in line with current policies in Nigeria, where existing flares have been legally collected from operators that did not reach final investment decisions as at the time the law on flare site confiscation by the federal government was exercised [20]. Project finance is assumed to be based on equity, as most flare reduction projects lack project finance requirements [4]. All model price inputs were revised against constant 2024 US Dollars with costs observed in year y escalated as $C_{2024} = C_y \times (D_{2024}/D_y)$, where D is the relevant US equipment price or GDP deflator. Naira-denominated tariffs or local costs are converted using the exchange rate corresponding to the stated base year.

The effects of inflation and exchange rates are also not considered in the base case calculations, while the real discount rate is tagged at 10 percent for NPV calculations. It should be noted that the 10% rate used is only a reference real discount rate for reconciling the reported NPVs; it is not presented as a Nigeria-specific investor hurdle. For a bankable estimate, a developer should test a risk-adjusted range reflecting country, technology, development, regulatory, market, and counterparty risk. Since the federal government of Nigeria has issued a cumulative five-year tax-free period for gas utilisation projects in midstream operations, the base case scenario assumes zero tax [21]. The straight-line depreciation method was applied to capital costs over a period of five years, expensing operating costs

and unlimited loss carry-forward. This assumption ensures the minimisation of the impact of taxes on the financial returns of the flare projects whose lifetime is taken to be seven years [4].

Furthermore, available gas in year t is calculated using $Q_t = Q_0 \times 0.85 \times (1 - 0.05)^{t-1}$, where Q_0 is the satellite-estimated daily flare volume, 0.85 is the recoverable fraction, and 5% is the assumed annual decline. These values are screening assumptions rather than measured production forecasts. Pre-treatment costs can significantly increase capital costs and lower the volume of gas available for monetisation. Other impurities that are non-hydrocarbons in nature are found in gas streams, such as hydrogen sulphide (H_2S) and carbon dioxide (CO_2). In the models developed in this work, it is assumed that amounts of such impurities are negligible, hence, pre-treatment for the purpose of removing impurities is not necessary. This assumption is backed by the work of Obuba et al. [22] who found an average of 0.52 ppm H_2S content, 0.00 CO_2 content and 0.00 N_2 content in a sample of twenty-three (23) gas reservoirs sampled across the Niger Delta region of Nigeria. It should be noted that for a bankable analysis, gas composition and contaminant removal requirements must be verified for each site.

As modular, plug, and play types of technologies are now available in the market and to forestall project oversizing, the lifetime of the project was limited to 7-year reflecting periods over which gas supply is reasonably predictable and reliable. Similarly, capital expenditure (CAPEX) is estimated based on the gas volume availability at the end of the third year of the project's lifetime. The third-year gas volume roughly coincides with the average volume available over seven years, at the assumed constant decline rate of 5% per annum. The modularity of the deployed technology helps to fully amortise the costs of equipment beyond the 7-year adopted project lifetime. In the sensitivity analysis, we also include cases with project durations of 5 years and 10 years.

3.4. Gas-to-Power

The first project scenario involved the installation and operation of power generation equipment near the flare site. The intention of the project developer is to generate and sell power to a third party by feeding power to an existing local grid. The transmission lines to the point of entry into the existing grid are assumed to be constructed by the project developer, while gas is purchased from the government of Nigeria at the approved floor price for gas at the flare as contained in the Request for Proposal (RFP) document of the Nigerian Gas Flare Commercialisation Programme (NGFCP). Although the gas sales value as estimated by the World Bank was US\$2.5/MMBtu [23], the government set the floor price at \$0.25 per Mscf to stimulate investment [20]. Annual electricity sold is $E_t = [Q_t \times 10^6 \times H/HR] \times 365 \times (1 - p)$, where H is gas heat content (Btu/scf), HR is generator heat rate (Btu/kWh), and p is parasitic consumption and auxiliary loss. Revenue is $R_{power,t} = E_t \times P_e$, where P_e is the realised electricity price. The developer bears generation, interconnection, and transmission-line costs and purchases the flare gas at the applicable price.

The CAPEX per megawatt was based on EIA [24] for small and medium flares, and EIA [25] for large flares. Similarly, the CAPEX for transmission (per kilometre) was obtained from [26] for all the flare scenarios. Gas-powered generators benefit from economies of scale, with large generators having less CAPEX. Wholesale electricity pricing was obtained from [27]. It was further assumed that parasitic gas usage for the three scenarios was between 3% for large flares, 2.5% for medium flares, and 2% for small flares. The efficiencies (in Btu/kWh) of the generators were 9894 Btu/kWh for small flares and 8295 Btu/kWh for medium flares [24], whereas the large flare efficiency estimates were 6441 Btu/kWh [28]. The heat content of the gas was estimated to be 1033 Btu/scf using the EIA [25]. Grid

distances adopted in the power model were deterministic for the purpose of scenario tests, not evidence about all sites of a given volume.

3.5. Gas-to-Pipeline

For gas-to-pipeline, the developer treats, compresses, and conveys gas to an existing pipeline. Annual revenue is $R_{\text{pipeline},t} = Q_{\text{delivered},t} \times 365 \times 1000 \times T$, where $Q_{\text{delivered}}$ is MMscf/d delivered after treatment and losses and T is the tolling fee in US\$/Mscf. Cash costs include gas treatment, compression, pipeline operation, right-of-way, and tie-in expenditure. Pipeline diameter and compression must be sized using the actual flow, inlet pressure, required delivery pressure, composition, and route profile.

As associated natural gas may contain contaminants and liquid petroleum gases, those must be removed to ensure that the dry gas is safely transported through high-pressure, long-distance pipelines to consumers [29]. Thus, as with gas-to-power, the CAPEX for the removal of LPG, compression, and dew point adjustment benefits significantly from economies of scale. The CAPEX (\$/MMscf per day) covering LPG removal, dew point adjustment, and compression was estimated from the World Bank document on technology overview for the utilisation of small-scale associated gas [30]. To ensure cost control for the development of the flare project, it is assumed that the flares are close to existing gas transportation pipelines. For small and medium flares, 1 km and 3 km were assumed, whereas for large flares, 5 km was considered. These distances were not measured at the selected sites and therefore cannot be justified as consequences of flare size or inferred to indicate that small flares are normally closer to pipelines or that large flares are normally farther away. A bankable estimate requires GIS screening followed by route survey, geotechnical assessment, right-of-way analysis, hydraulic design, and confirmation of available pipeline capacity.

The project developer delivers the gas to an existing pipeline infrastructure and was paid a tolling fee to cover the costs of gas treatment and compression. Pipeline CAPEX per kilometre (subject to pipeline diameter) was estimated from Ofgem [31]. This source was selected because no publicly available, disaggregated pipeline-construction CAPEX database exists for the Nigerian context, and the required equipment is not manufactured locally in Nigeria. This estimate is used as international reference for imported material and fabrication only. Bankable estimates must be adjusted for local construction productivity, terrain, logistics and contractor risks.

3.6. Compressed Natural Gas

For gas-to-CNG, the developer treats and compresses gas, loads it into road-transport modules, and sells it to industrial, power, transport, or pipeline-injection customers. Revenue is $RCNG_t = \min(Q_t, Q_{\text{fleet},t}, Q_{\text{market},t}) \times 365 \times 1000 \times PCNG$, where Q_{fleet} is fleet-delivery capacity, Q_{market} is verified market absorption, and $PCNG$ is the realised net selling price. Fleet capacity is $Q_{\text{fleet}} = \text{payload} \times \text{trips per vehicle per day} \times \text{number of vehicles} \times \text{fleet availability}$. Trip frequency must be derived from route distance, road speed, loading time, unloading time, driver-hours, and maintenance downtime.

As with gas-to-power, the CNG project enjoys significant benefits from the economies of scale. That is, the higher the processed volume, the lower the CAPEX. Estimates for CAPEX components, covering dew point adjustment, LPG removal, compression, trucks, and containers, were obtained from Abu et al. [16] and World Bank [30]. Operating costs associated with this project, covering preprocessing, compression, and delivery by pressurised containers to distances of not more than 150 km, were assumed to be 13% of the CAPEX [4]. To validate this, an independent benchmark was reviewed. Industry guidance for gas-processing and pipeline systems shows that annual OPEX typically ranges

between 2 and 5% of Total Installed Cost, covering maintenance, labour, utilities, insurance, and related expenses. Over a 5–10 year operating period, these values accumulate to a similar order of magnitude as the 13% assumption [32]. The high OPEX in this scenario is due to the need to operate a fleet of trucks for the transportation of CNG, in addition to treatment and compression equipment. The distance for CNG delivery is heavily dependent on market price. The more favourable the market price, the longer the distance that the project developer may be willing to deliver the product. However, this comes with additional manageability and road-safety risks. As the assumptions in this model do not fully substitute for a detailed logistic model, the reported results are illustrative economic screens and should not be considered as evidence that the modelled sites possess sufficient road capacity or market demand.

4. Results: Financial Screening and Deterministic Sensitivities

4.1. Gas-to-Power Model

At the 10% reference discount rate, the Amukpe and Oziengbe South gas-to-power cases have negative NPVs of –US\$7.68 million and –US\$17.30 million, with IRRs of –7% and 1%, respectively. The Oben case has an NPV of US\$20.10 million and an IRR of 17%. The differences reflect the combined effects of the assumed heat rates, installed costs, grid-connection distance, recoverable volume, and electricity revenue; they are not interpreted as a pure flare-size effect. Figure 1 shows the base case NPV plot while Figure 2 indicates the obtained IRRs for the three flare scenarios.

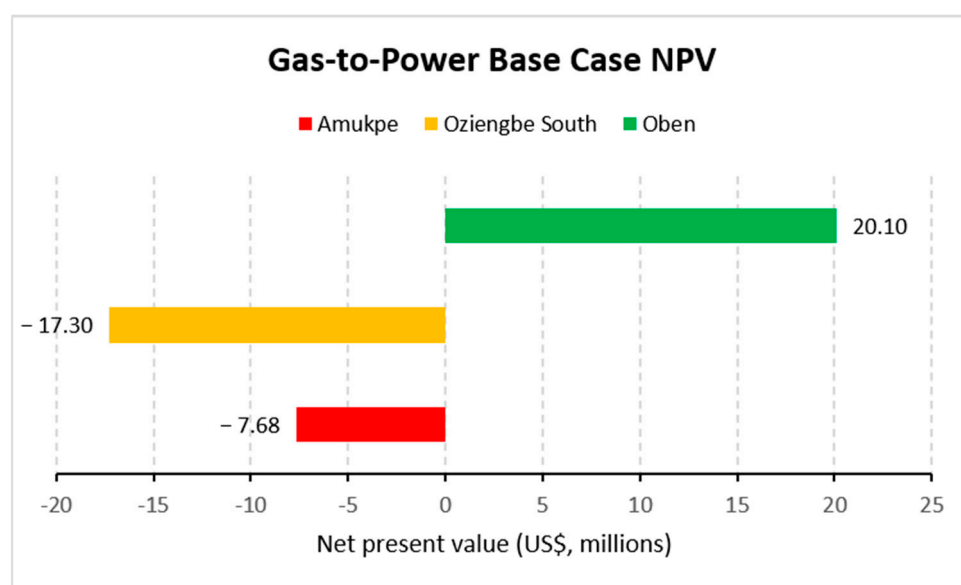


Figure 1. Gas-to-power base case NPV.

The deterministic tests indicate that the Oben power case is particularly exposed to the realised power price and grid-connection distance. A US\$0.01/kWh reduction lowers the reported IRR from 17% to 10%, while a 50% increase in grid distance lowers it to 7%. The results therefore depend on a credible offtake tariff and a measured interconnection route. Changes in the flare-gas purchase price have a smaller effect in the reported model because fuel acquisition is a relatively small share of the total project value.

A five-year operating period makes all three power cases unattractive in the deterministic screen, while a ten-year period improves returns. This result does not demonstrate that clustering or supplementation with non-associated gas is feasible. Such strategies would require a separate gathering-system design, inter-field distance analysis, gas-compatibility

assessment, ownership and allocation agreements, and confirmation that the combined supply is simultaneous and contractually available. Figure 3 shows the results of the deterministic tests.

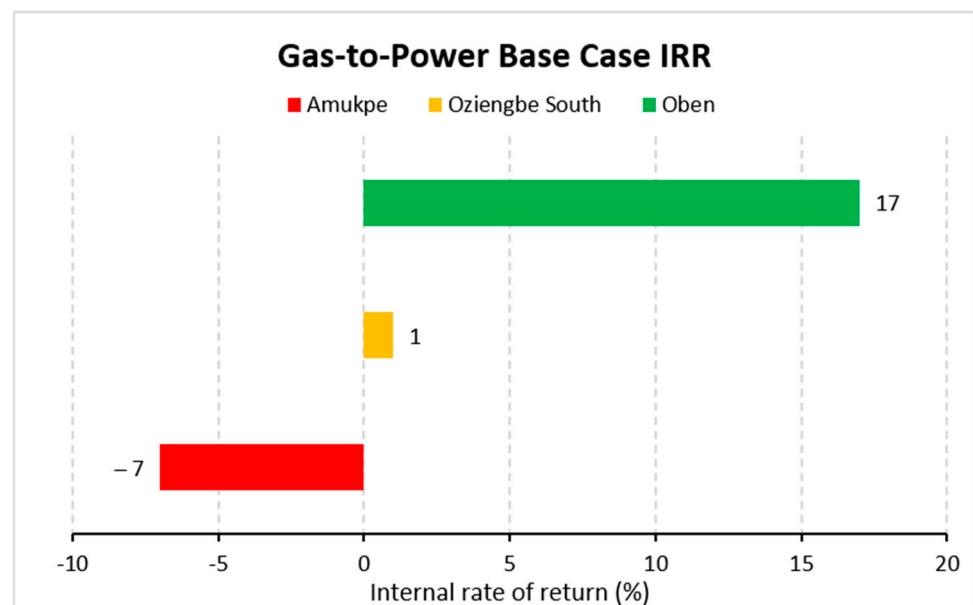


Figure 2. Gas-to-power base case IRR.

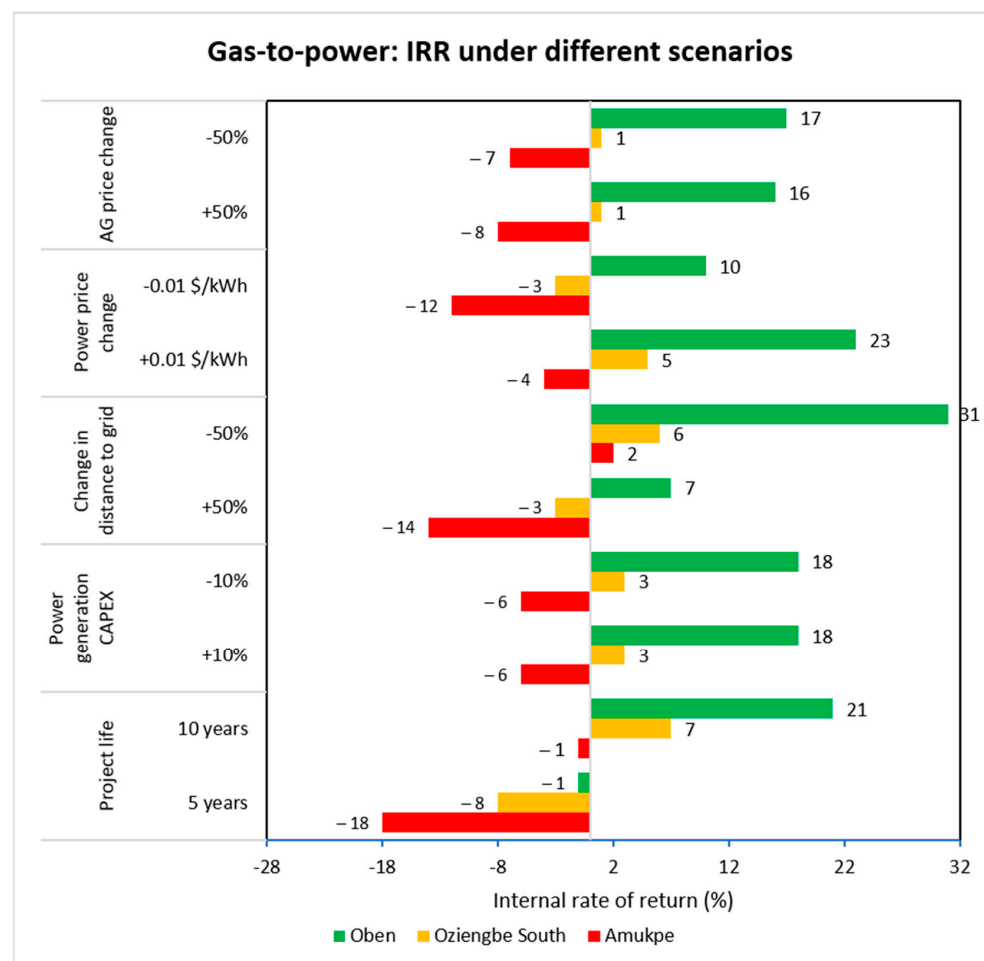


Figure 3. Gas-to-power deterministic sensitivity screening plot.

4.2. Gas-to-Pipeline Model

The reconciled gas-to-pipeline results are: Amukpe NPV –US\$0.72 million and IRR 1%; Oziengbe South NPV US\$2.75 million and IRR 21%; and Oben NPV US\$7.32 million and IRR 25%. The positive results for Oziengbe South and Oben are conditional on the assumed tolling fee, treatment cost, and illustrative tie-in distances. They do not establish that all medium- or high-volume flares are suitable for pipeline delivery.

Figure 4 depicts the base case NPV while Figure 5 shows the IRR for all sites under consideration.

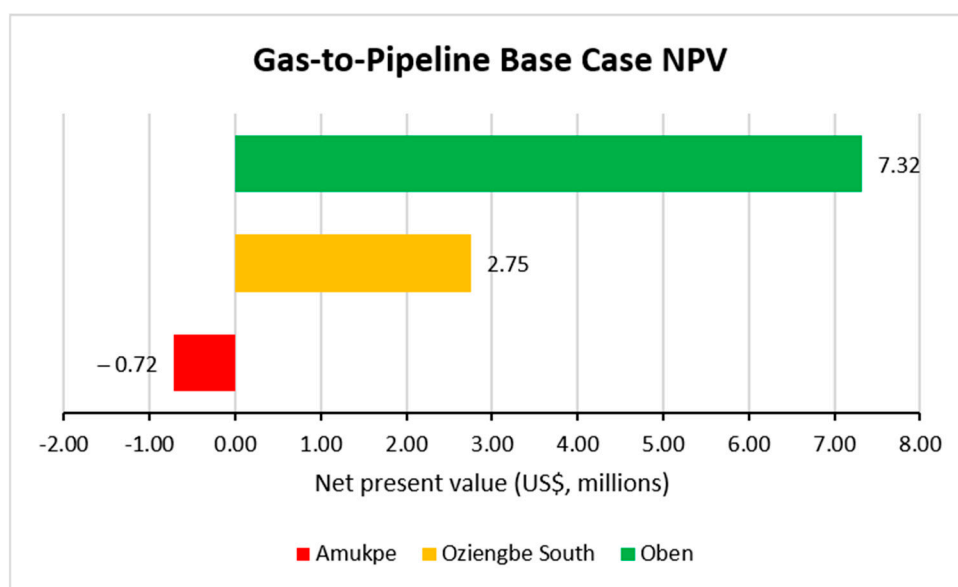


Figure 4. Gas-to-pipeline base case NPV.

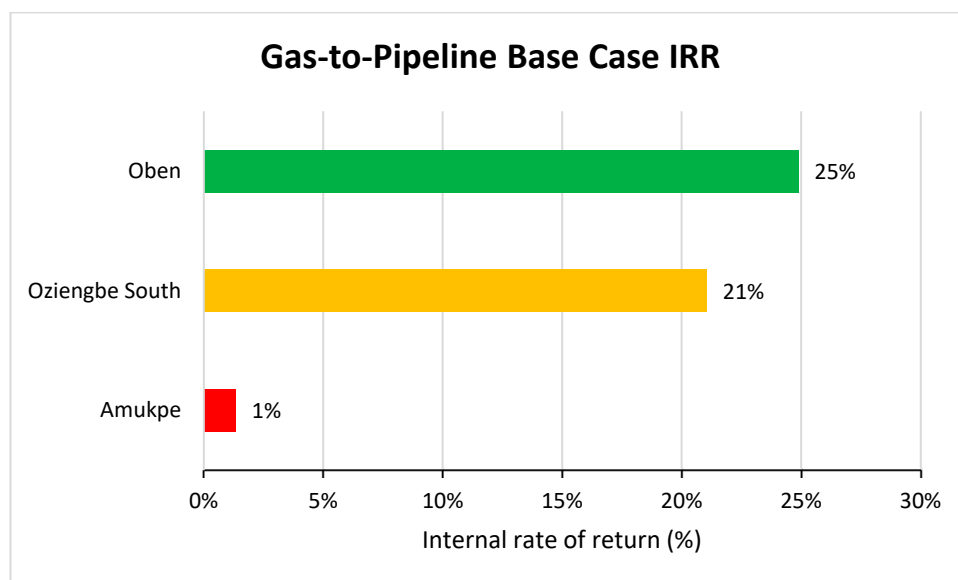


Figure 5. Gas-to-pipeline base case IRR.

The deterministic screening confirms that tolling revenue, CAPEX, project life, and pipeline distance materially affect returns. For the Amukpe case, a 10% toll reduction or CAPEX increase can make the already weak return negative, whereas favourable changes improve IRR but do not provide a sufficient risk margin. For Oziengbe South and Oben, the reported IRRs remain above 10% under the tested one-at-a-time changes, but this is

not a robustness result because adverse variables may occur jointly. Figure 6 depicts the deterministic sensitivities for this model.

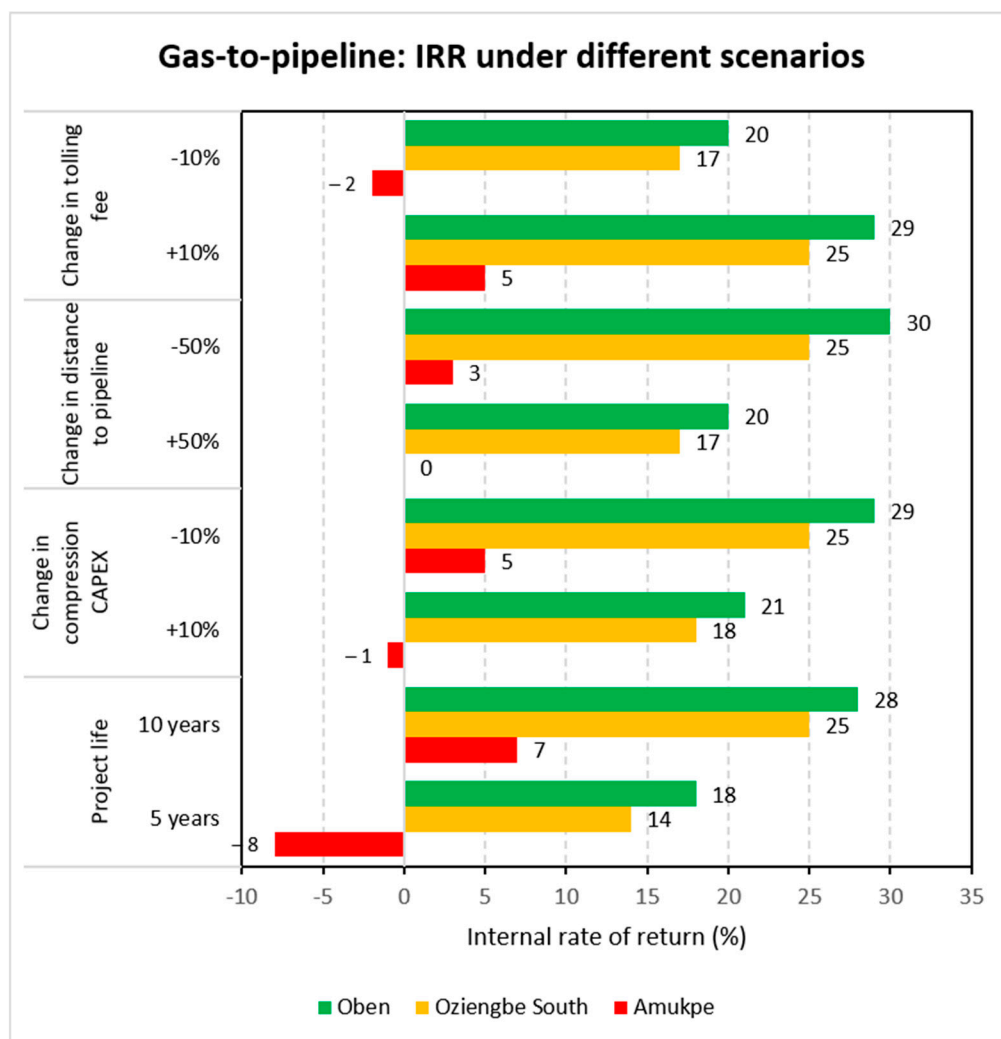


Figure 6. Gas-to-pipeline deterministic sensitivity screening plot.

The pipeline pathway is therefore interpreted as potentially attractive at Oziengbe South and Oben under the stated assumptions, subject to verification of route distance, gas specification, pressure, tie-in capacity, tolling contract, and operator access. The analysis does not imply a general rule that a flare above 5 MMscf/d is viable for pipeline monetisation.

4.3. Gas-to-CNG Model

The gas-to-CNG results show Amukpe's NPV as −US\$3.97 million and IRR −14%; Oziengbe South NPV US\$7.20 million and IRR 25%; and Oben NPV US\$21.62 million and IRR 33%. These outputs remain conditional on the assumed CNG price, aggregate OPEX ratio, delivery radius, and sufficient fleet and market capacity. Figures 7 and 8 depict these values.

In the deterministic screening, CNG price and compression CAPEX are the largest reported drivers for Oziengbe South and Oben. A 10% CNG-price increase raises the IRR by approximately six to seven percentage points, while a 10% CAPEX reduction produces a similar improvement. This sensitivity confirms that negotiated offtake price, compression specification, imported-equipment cost, and fleet utilisation require detailed due diligence.

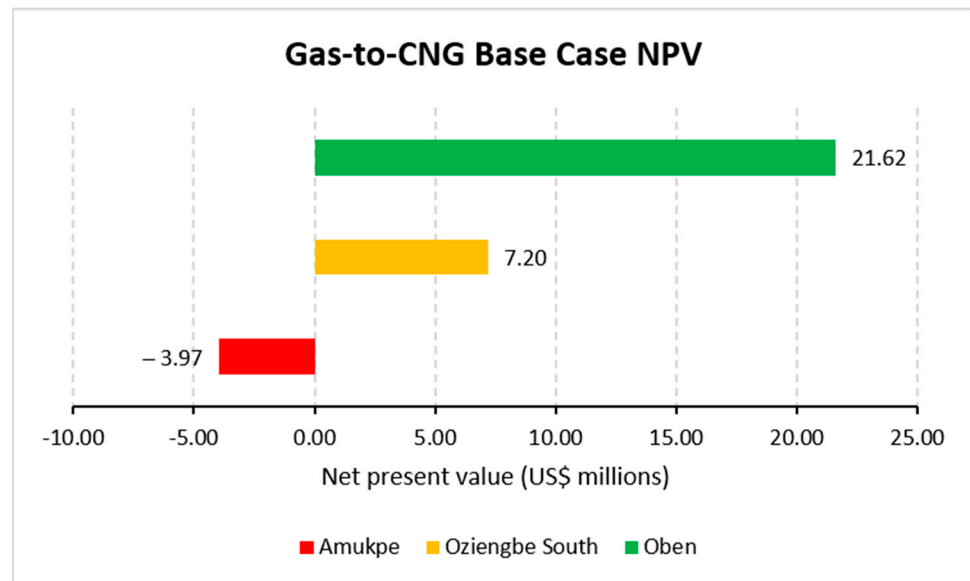


Figure 7. Gas-to-CNG base case NPV.

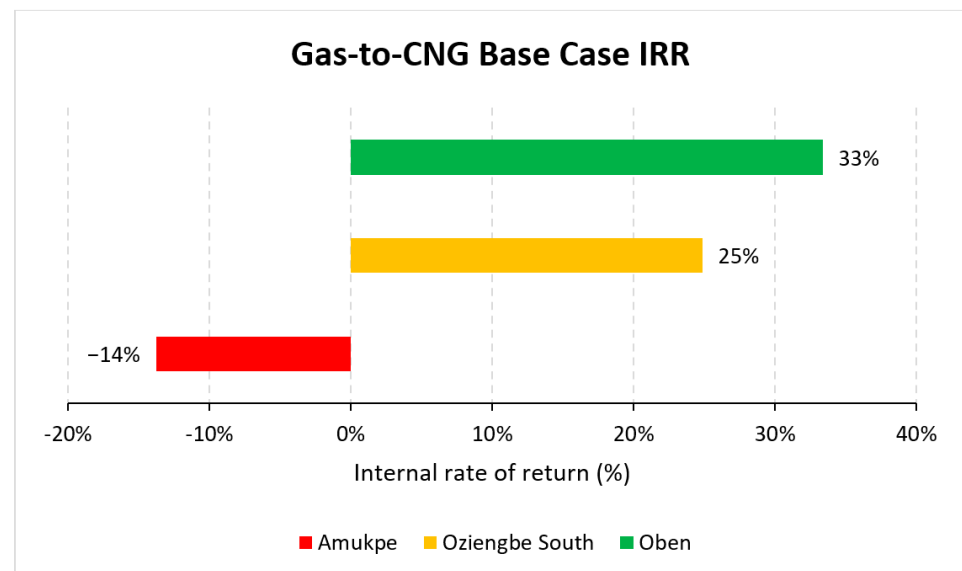


Figure 8. Gas-to-CNG base case IRR.

Changes in flare-gas purchase price and project life have smaller effects in the reported model. However, this result may change once route-specific transport costs, fleet replacement, working capital, payment delay, and customer default are modelled. The current CNG analysis therefore assesses preliminary economic attractiveness only. Figure 9 shows the deterministic changes in the IRR of the Gas-to-CNG model.

4.4. Cross-Case Numerical Audit and Interpretation

Table 3 provides the summary of the base case values obtained throughout the analysis in this study. The results compare technologies within each named case; they do not rank technologies for Nigeria as a whole. A positive NPV at the 10% reference rate indicates preliminary economic attractiveness under the model assumptions, not resilience, financeability, or bankability.

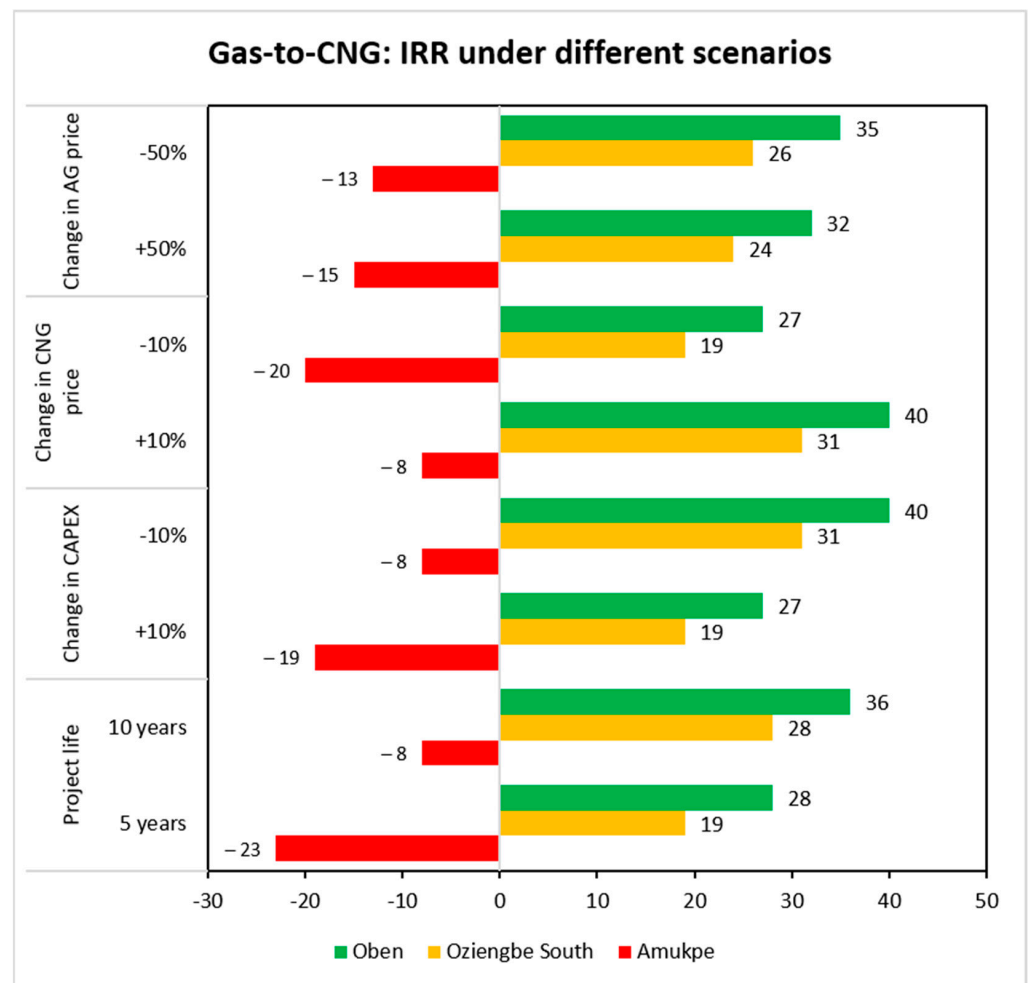


Figure 9. Gas-to-CNG deterministic sensitivity screening plot.

Table 3. Summary of base case financial-screening results (NPV at 10% reference real discount rate).

Site	Flare Volume (MMscf/d)	Gas-to-Power NPV/IRR	Gas-to-Pipeline NPV/IRR	Gas-to-CNG NPV/IRR
Amukpe	1.16	−US\$7.68m/−7%	−US\$0.72m/1%	−US\$3.97m/−14%
Oziengbe South	5.15	−US\$17.30m/1%	US\$2.75m/21%	US\$7.20m/25%
Oben	10.88	US\$20.10m/17%	US\$7.32m/25%	US\$21.62m/33%

At Amukpe, all three pathways have negative NPVs, and only gas-to-pipeline has a marginally positive IRR of 1%. The case therefore does not support a stand-alone investment under the stated assumptions. It also does not, by itself, prove that clustering is feasible; it identifies aggregation as a hypothesis that requires spatial, technical, contractual, and market analysis.

At Oziengbe South, gas-to-pipeline and gas-to-CNG have positive NPVs and IRRs of 21% and 25%, respectively, while gas-to-power has a negative NPV and 1% IRR. The result demonstrates technology dependence at this particular site and under the stated assumptions. It should not be generalised to every flare between 5 and 9 MMscf/d.

At Oben, all three pathways have positive NPVs in the screening model. Gas-to-CNG has the highest reported NPV and IRR, followed by gas-to-pipeline on IRR and gas-to-power on NPV. The ordering is conditional on CNG price and logistics, pipeline

distance and tolling, and electricity tariff and interconnection cost. It is not a universal technology ranking.

The evidence obtained from this study has material limitations to be considered for subsequent analysis of this nature. First, each flare-volume category contains only one site, and volume is confounded with operator, infrastructure, location, gas characteristics, and market access. Second, the public-data cost estimates are not equivalent to vendor quotations or front-end engineering design. Third, the reported one-at-a-time tests do not quantify joint uncertainty. Fourth, the model is unlevered and does not include debt sizing, interest during construction, repayment, reserve accounts, financing fees, hedging, or lender covenants. Fifth, gas supply, site access, tolling, electricity or CNG offtake, payment security, and regulatory enforcement are not represented by executed contracts. Sixth, avoided flaring, methane slip, life-cycle emissions, and displacement effects are not calculated. The study therefore reports a preliminary economic screening, not project bankability or environmental performance.

5. Conclusions/Policy Implication

Nigeria's third-party flare-allocation framework creates a legitimate role for independent developers, but the commercial outcome is site- and contract-specific. Government and regulators can improve project preparation by publishing verified flow histories, gas composition, infrastructure maps, tie-in requirements, title and access information, and standardised commercial terms. Better data would reduce development risk and allow bidders to compare technologies on a consistent basis.

The Amukpe results suggest that a low-volume stand-alone case may be difficult under the assumed costs and prices. They do not establish that every flare near 1 MMscf/d is uneconomic, because a site with nearby infrastructure, a high-value captive market, low treatment requirements, or concessional support could perform differently. Conversely, a larger flare can remain unattractive if infrastructure, market, or contractual conditions are poor.

The Oziengbe South results show that positive returns for pipeline and CNG can coexist with an unattractive power case at the same site. The relevant implication is not that "medium flares are viable", but that technology selection must follow verified infrastructure and market conditions. A final investment decision would require engineering design, vendor quotations, route and market studies, contracts, and risk-adjusted financing analysis.

The Oben results are favourable across all three screening cases, but the technology ranking should not be interpreted independently of the assumptions. Oben's gas-hub characteristics may provide advantages that are absent at other high-volume flare sites. This is precisely why the study cannot infer national volume thresholds from the three cases.

Clustering may create economies of scale, but it is not validated by the present model. A clustering study must map inter-site distances, gathering facilities, gas compatibility, ownership, allocation and measurement, supply simultaneity, and the incremental market. Similarly, no environmental benefit is claimed because avoided-flare emissions, methane slip, conversion emissions, transport emissions, and displacement effects were not quantified. These are priorities for subsequent engineering and life-cycle assessment.

For policy purposes, the most defensible use of the model is as an initial screening tool that identifies where better data are worth collecting. It should not be used to award projects, prescribe technology, declare a site bankable, or validate a nationwide clustering policy without the additional evidence specified above.

This study compares gas-to-power, gas-to-pipeline, and gas-to-CNG at Amukpe, Oziengbe South, and Oben from an independent developer's perspective. After numerical reconciliation, the results show negative NPVs for all three Amukpe cases; positive

NPVs for pipeline and CNG but not power at Oziengbe South; and positive NPVs for all three pathways at Oben. These findings are conditional on the stated inputs and do not identify general viability thresholds for Nigerian flare-size classes. The analysis establishes preliminary unlevered economic attractiveness, not bankability. Its practical contribution is to make the cash-flow logic, evidence boundaries, and outstanding due-diligence requirements explicit so that future site assessments can replace illustrative assumptions with measured engineering, market, contractual, environmental, and financing data.

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Abbreviations

The following abbreviations are used in this manuscript:

Btu/kWh	British Thermal Units per Kilowatt Hour
Btu/scf	British Thermal Units per Standard Cubic Feet
CAPEX	Capital Expenditure
DCF	Discounted Cash Flow
GGFR	Global Gas Flaring Reduction
IRR	Internal Rate of Return
MMscf/d	Million Standard Cubic Feet per Day
NPV	Net Present Value
OPEX	Operating Expenditure

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