Nigeria's super-emitter flares

an evaluation of trends and causes of natural gas wastage

An analysis of five offshore global super-emitter flares and their related field performances

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1. Introduction

This study was conducted for Oxford Policy Management Nigeria Limited (OPM) as part of the Facility for Oil Sector Transparency and Reform (FOSTER) programme and was delivered in March 2023. It is a follow-on study to that completed in August 2022, which had the following objectives:

Investigate Nigeria's natural gas flare performance to:

1. Carry out a Nigeria country assessment on how flaring has changed over time compared to its oil production trend (and what that means for flare intensity).
2. Identify the flares in Nigeria that rank within the global top 300 super emitters.
3. Link this to detailed observations for four Nigerian super emitters identified in the Niger Delta region, to show how flare performance (as shown by satellite data) and operational performance are interrelated. Such detailed flare analysis can identify events indicative of much increased methane emissions. Assess the local context of these flares and evaluate the potential impact on local communities.
4. Relate this analysis to improve understanding of the background trends and opportunities for further flare reductions of these 4 super-emitters and a further 58 flares in a 130 x 140 km area of interest east of Warri in the Niger Delta region.
5. Assess the key lessons from the evaluation and suggest how these can be used as a diagnostic tool to monitor whether development promises and production quality standards for individual assets are being met.
6. Provide advice on next steps to use the satellite methodology to assess and compare the operational effectiveness of key Nigerian production assets, such as deep water Floating Production Storage and Offloading vessels (FPSOs).

This Phase II study undertakes a similar detailed flare assessment based on VIIRS satellite data for five Nigerian offshore FPSO facilities.

Incomplete combustion of natural gas in gas flaring process is a key contributor to methane emissions as well as a range of other harmful chemicals. Cutting methane emissions is the fastest opportunity to immediately slow the rate of global warming, even as progress is made on decarbonization of energy systems. It provides an unusual and attractive combination: significant contributions to the global public good of emissions reduction as well as the local public good in many of the 30 developing countries highly dependent on oil and gas production. The World Bank Global Gas Flaring Reduction (GGFR) finds that 54 oil producers have committed to end routine flaring, yet net flaring emissions increased in 2021; essentially unchanged over the past decade. Most wasted gas flared comes from developing countries.

But, the urgency to tackle methane emissions has only grown[1]. In March 2023, the IPCC Synthesis Report[2] on the findings of its 6 major Reports since 2018 sets out a range of steps to cut emissions starting immediately to keep to the 1.5 ^{o}C Paris target. Reducing methane

[1] Nature Communications, "Impact of interannual and multidecadal trends on methane-climate feedbacks and sensitivity", IPCC April 2022 report on Mitigation of Climate Change; https://www.nature.com/articles/s41467-022-31345-w.pdf;
[2] IPPC, "Synthesis Report of the Sixth Assessment Report", 2023; https://www.ipcc.ch/ar6-syr/.

emissions from the fossil fuel industry is highlighted. In 2022, the IEA estimates that methane emissions from the global energy sector (responsible for 40% methane emissions from human activity) increased to a near record, after already rebounding by almost 5% in 2021. [3]

Action can be taken quickly. At a high level UNU-WIDER COP27 event, the key conclusion was that "reduction of methane emissions by addressing the huge global wastage of gas caused by flaring and venting should be immediately prioritised for global emissions objectives.

Unlike other climate-change measures, policies to achieve these reductions do NOT require either new technologies or large financing by governments. Indeed, they can generate significant increases in fiscal revenues and contribution to the UNSDGs – an obvious boon for many countries. Moreover, given the relatively small initial costs and effort involved in reducing methane emission by wasting less gas, it should be an attractive opportunity for the private sector as well as for donors and oil and gas producing countries".

Nigeria has demonstrated a remarkable decline in gas flaring from 21.4 Bcm in 2005 to 6.6 Bcm in 2021. Many elements and efforts have contributed to this success, including regulatory policies, fiscal policies (Nigeria imposes taxes on gas flared), development of infrastructure and transparency measures (such as Nigeria's flare tracker).

Yet, 181 flares were observed in Nigeria in 2021. Of this population, 119 flares burn on average more than 1 million standard cubic feet per day (MMscf/d) and 19 burn more than 10 MMscf/d. Among these most prolific flares are those that are considered to be global Top 300 super-emitters based on their persistent high rate flaring of at least 5.7 MMscf/d during 2017 to 2021. Nigeria has 18 such global super emitters.

In this summarising report we combine and compare the performance of five of Nigeria's largest offshore natural gas flaring assets. Nigeria government has a guideline of zero routine flaring and each of the five super-emitter flares investigated was based on a development that was to avoid routine flaring by reinjection of the produced gas into to reservoir to assist oil recovery, or in the case of Bonga, to export the gas by Nigerian LNG plant (NLNG) on Bonny Island. The analysis shows that although companies invested in facilities to prevent routine flaring, in reality these facilities did not perform or their performance was not maintained.

Detailed individual flare operations performance analysis reports have been written for the Agbami, Yoho, Bonga, Abo, Usan assets. These individual reports that are part of the same study form the basis for the overview provided in this summary report.

The objective of this analysis is to better understand the background, trends and opportunities for further flare rate reductions of super-emitters. This is important as the top three percent of all global flares burn more than 43% of all gas wasted from the world's 9,699 flares measured in 2021. Flaring is not only a significant waste of a valuable energy resource, it also affects air quality and causes a health risk and contributes to global warming, particularly through methane emissions due to poor flare operations. If the field development

[3] IEA Global Methane Tracker 2022; https://www.iea.org/reports/global-methane-tracker-2022/overview.

depends on gas-reinjection, excess flaring may compromise oil recovery as well as gas conservation. [4] [5]

A list of abbreviations and units is included in this paper in Appendix D.

EnergyCC and Oxford Policy Management sent a copy of this report in draft to the Operators of the five offshore super-emitters and to Nigeria LNG with the request to review the draft and correct any factual errors. The request was sent to the company representatives provided by NOSDRA, the Nigeria Regulator. It asked for comments in a four-week period and indicated that feedback received would be incorporated into the draft report before publication. Comments were received from the ENI Nigeria Public Affairs Department and are reproduced in Section 6.3 of this report. ENI's comments refer to three inconsistencies on flaring measurement, gas production capacity and injection, and oil spills. ENI also sets out four actions to be implemented by the end of 2023 to improve its flaring and methane emissions, after which further solutions will be defined to strengthen and improve its emissions framework. A second follow up request was sent to the remaining Operators: Chevron Nigeria, Exxon Mobil Nigeria, Shell Nigeria, and TotalEnergies with another four-week period for comment. Comments were received from TotalEnergies (October 2023) and from Shell (November 2023). No further comments were received since. TotalEnergies mentions in its comments that it engages with Shell (operator of Bonga) and Exxon (operator of Usan) as partners, as TotalEnergies does not operate these assets. For its operated assets in Nigeria it is taking steps in three areas: flaring and venting; leaks and fugitives reduction and fuel gas reduction. TotalEnergies encourages the operators of assets where it is partner to take similar steps. Shell provides five clarifications in its comments and offers a table on Bonga oil production, flare volumes and flare intensity for the period 2012-2023. EnergyCC's responses to these comments from ENI, TotalEnergies and Shell are also included.

2. Flare Asset Selection

Whereas the earlier EnergyCC report on Nigeria's super-emitter flares[6] focused on land-based operations, in this study five offshore super-emitter flares were selected for analysis. The assets investigated were similar in development type. Four of the five (Agbami, Usan, Bonga and Abo) are deep-water developments utilizing subsea wells and Floating Production, Storage and Offloading (FPSO) facilities. The fifth, Yoho, is a shallow water development, with an FPSO as Early Production Facility (EPS), followed by a Bridge Linked Platform (BLP)

[4] Romsom, E., and K. McPhail (2021). 'Capturing Economic and Social Value from Hydrocarbon Gas Flaring and Venting: Evaluation of the Issues'. WIDER Working Paper 2021/5. Helsinki: UNU-WIDER. https://doi.org/10.35188/UNU-WIDER/2021/939-6

[5] Romsom, E., and K. McPhail (2021). 'Capturing Economic and Social Value from Hydrocarbon Gas Flaring and Venting: Solutions and Actions'. WIDER Working Paper 2021/6. Helsinki: UNU-WIDER. https://doi.org/10.35188/UNU-WIDER/2021/940-2

[6] Etienne Romsom and Kathryn McPhail, EnergyCC, "Nigeria's super-emitter flares - an evaluation of trends and causes of natural gas wastage: reducing emissions and improving human health. A regional analysis of onshore global super-emitter flares in the Niger Delta region", August 2022.

development utilizing wellhead platforms and with oil stored and offloaded through a Floating Storage and Offloading (FSO) vessel.

Candidate Nigeria offshore assets to be considered for detailed flare evaluation (see also Appendix A) have been subjected to the following selection criteria:

- Producing during 2012 – 2022 period
- Materiality in terms of oil production
- Availability of monthly oil production data
- Materiality in terms of natural gas flaring (global super-emitters)
- Detailed gas flaring data available from VIIRS
- Variety of operators (to compare operational performance)

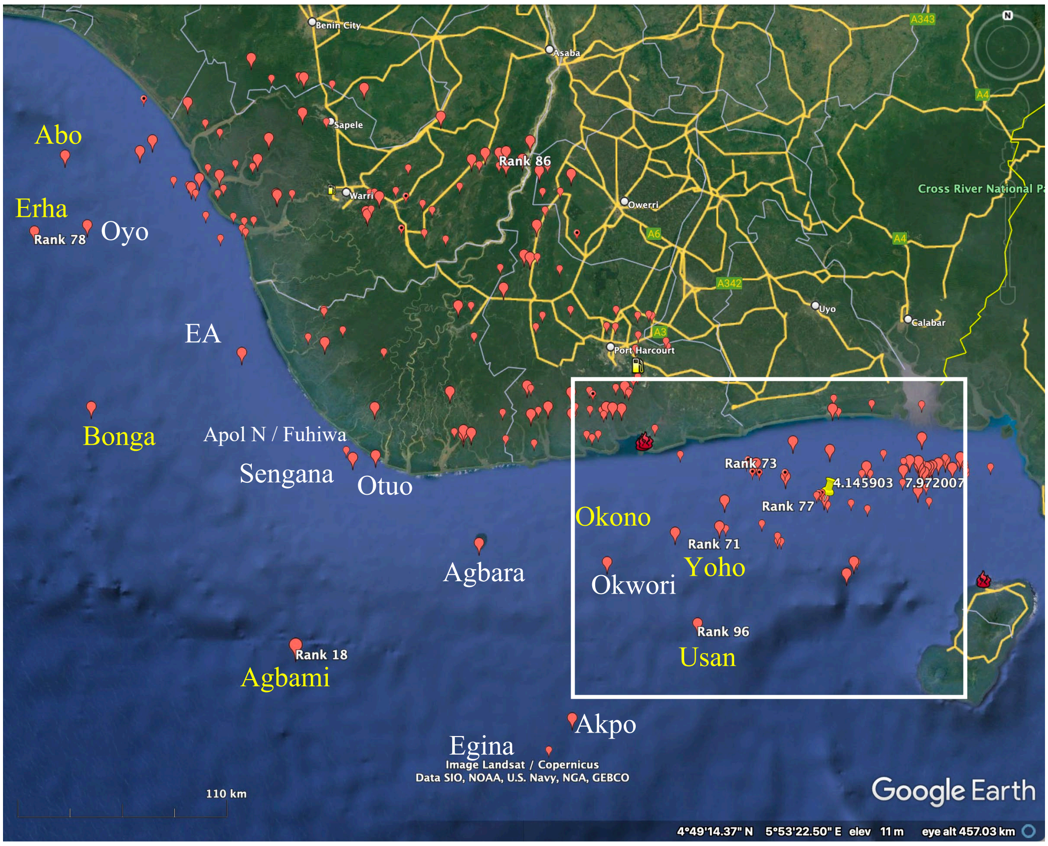
The assets that matched the above criteria have been highlighted in Figure 1 and 2, and are listed together with Nigeria's largest offshore flares in Table 1. Four super-emitter flare assets were not included as no oil production data was obtained for these. Erha and Okono matched the selection criteria (and could be subject for further study), but were superseded by Yoho and Abo, respectively, that are assets operated by the same companies, but ranked higher.

***Table 1**: asset selection for offshore super-emitter flaring study*

#	Name	Operator	Latitude	Longitude	Global flare ranking	Nigeria flare ranking	production (mln bbl in 2022)	Selected
1	Agbami	Chevron	3.4653	5.5641	39	1	44.592	yes
2	Oso	XOM	4.3046	7.6595	62	2	N.A.	no
3	Unam	XOM	4.2898	8.1670	108	3	N.A.	no
4	Edop	XOM	4.1460	7.9719	110	4	N.A.	no
5	Yoho	XOM	4.0171	7.4918	119	7	10.008	yes
6	Usan	Total	3.5755	7.3938	130	9	15.664	yes
7	Erha	XOM	5.3588	4.3420	136	10	21.598	fall-back
8	Akam	Addax	4.3166	8.3667	185	13	N.A.	no
9	Okono	ENI	3.9895	7.2900	193	14	4.160	fall-back
11	Abo	ENI	5.7084	4.4812	206	16	6.006	yes
12	Bonga	Shell	4.5546	4.6159	348	22	38.352	yes

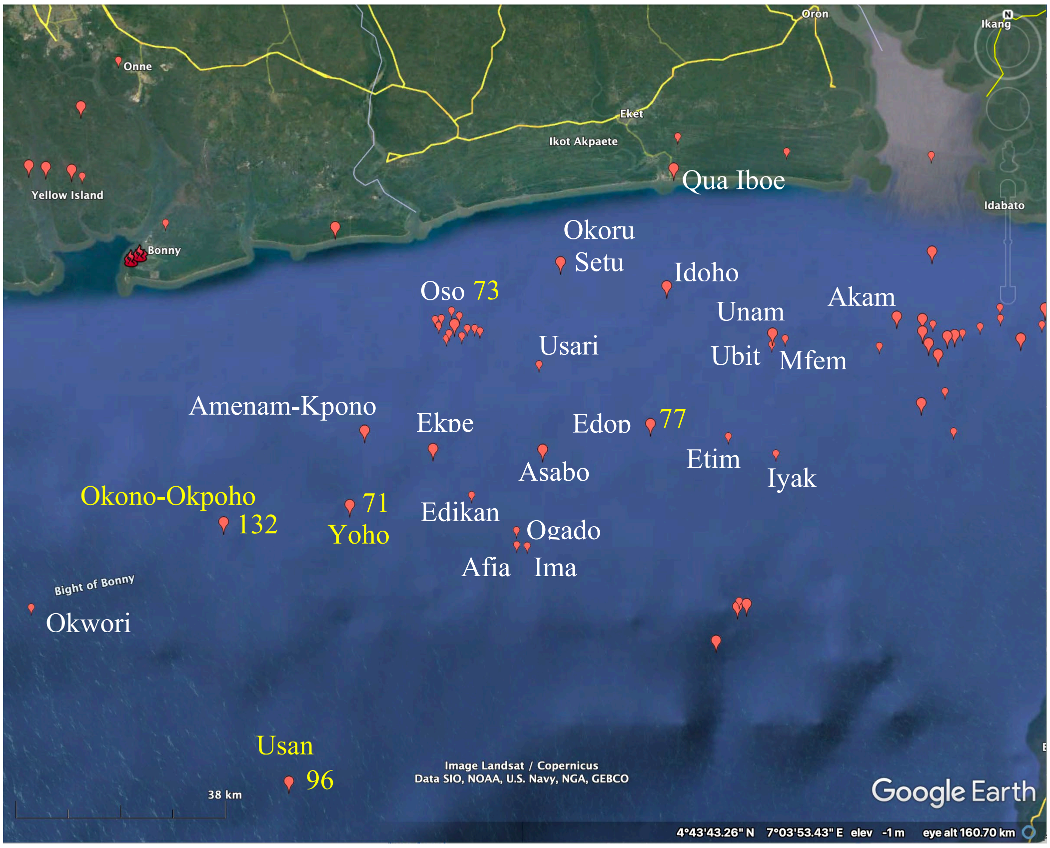
***Note**: Flare ranking during 2017-2021 period. Flares ranked 5th , 6th and 8th largest in Nigeria (Kwale gas plant, Ebendo flow station, and Obiafu-Obrikom gas plant, respectively) were studied in detail in the previous OPM project, with scope focused on Niger Delta flaring assessment. Assets selected in this study are shown in green.*

Figure 1*: Overview of Nigeria flare assets (2017 reference) and selected offshore field names.*



Note*: Assets matching selection criteria are shown in yellow; see Figure 2 for details of zoom-in area.*

Figure 2*: Detail of Nigeria flare assets (2017 reference) and selected offshore field names.*



Note*: Assets matching selection criteria shown in yellow; numbers reflect global flare ranking in 2017.*

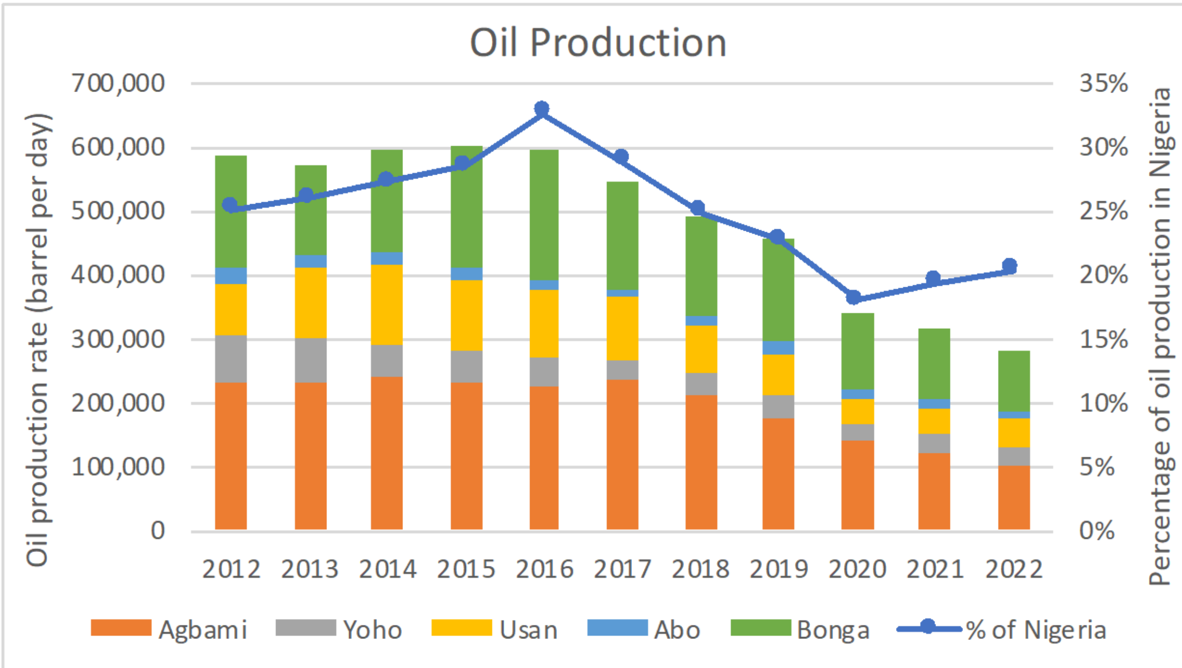
Source Figure 1 and 2: *authors' illustration based on Google Earth and VNF data from Payne institute, Colorado School of Mines* *https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/.*

Data for this study have been obtained through a multitude of public sources. By scouring a large number of online maps (e.g. from oil company websites), it was possible to match asset names with their corresponding gps locations for the most relevant offshore assets. Monthly production data were obtained from Nigerian National Petroleum Corporation (NNPC), Nigerian Upstream Petroleum Regulatory Commission (NUPRC) and Department of Petroleum Resources (DPR). Asset flare data were obtained from the global gas flare catalogue provided by the Earth Observation Group, The Payne Institute for Public Policy, Colorado School of Mines.

3. Super-emitter operations performance overview

As mentioned above, each of the five offshore assets selected and analyzed was designed not to flare routinely. Yet, despite their original development plans, each of these assets flare at a scale that make them super-emitters at a global scale. The assets evaluated are not only material for their gas flaring emissions, but they are also significant for Nigeria's oil production, as shown in Figure 3.

Figure 3*: Oil production from the five super-emitters reviewed.*



Source: *authors' illustration based on oil data from NNPC* *https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx* *(accessed February 2022).*

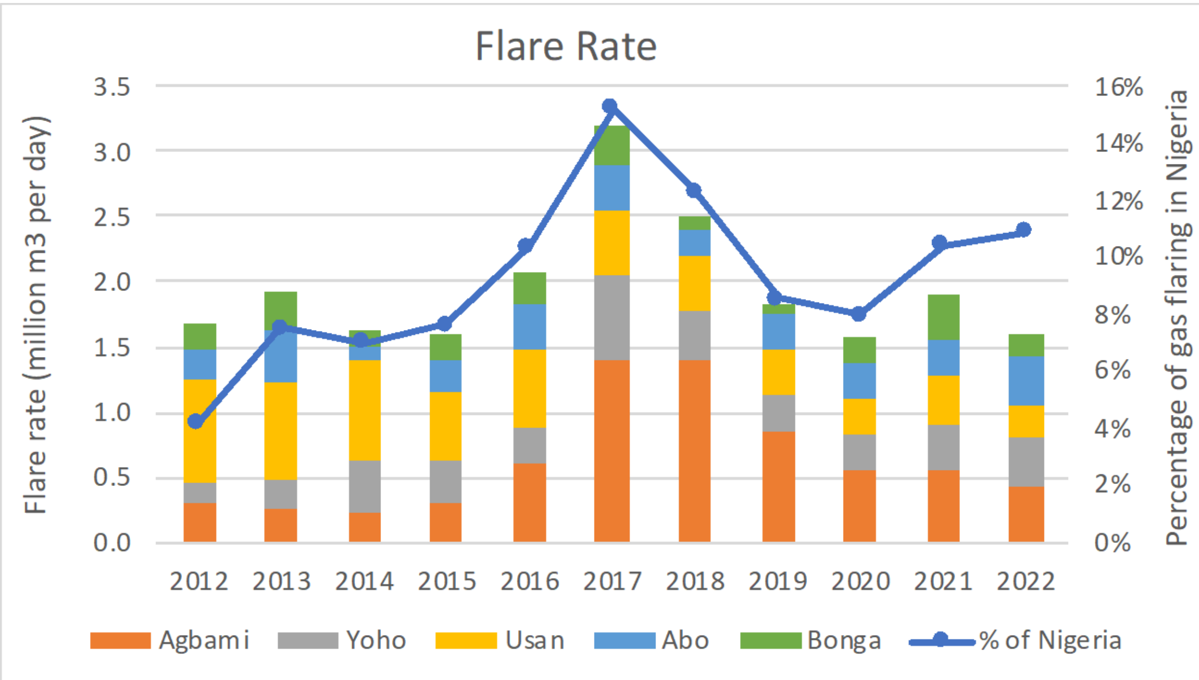
Note: *Oil production for the five offshore assets is shown in barrels per day (bpd) as stacked bars (left axis) and as percentage of Nigeria's total production (blue line) on the right axis.*

In 2016, the five assets provided one third of Nigeria's total oil production, but their contribution has been declining since to 20 percent. This is partially due to the offshore assets becoming more mature. However, detailed evaluation in the individual asset reports describe the impact of operational performance (and particularly flaring) on oil production and oil recovery.

In Figure 4, the annual average flare rates of the five assets are shown for the period 2012-2022 and compared with Nigeria's total flare rate. In 2017, the five assets were responsible for 15% of Nigeria's total gas flaring, but this share has been declining since to a low of 8 percent in 2020, mainly due to (OPEC+) production curtailment that year. In 2022, flaring had increased again to 11% of Nigeria's total. The amount of gas flared from the five assets in 2022 was the same as eight years earlier, in 2014.

Over the total 2012-2022 production period, these five assets contributed about a quarter to Nigeria's oil production and 9% to its overall gas flaring. In 2012, the contributions to oil production were 25% and gas flaring 4%, respectively. In 2022, these contributions had changed to 20% of oil production and 11% of gas flaring, respectively. This indicates that the flaring intensity (i.e. the amount of gas flared per barrel per oil produced) for the five assets was markedly better in the earlier phase of the review period, it gradually worsened as their share of oil production declined and gas flaring increased.

***Figure 4**: Gas flaring from the five super-emitters reviewed.*

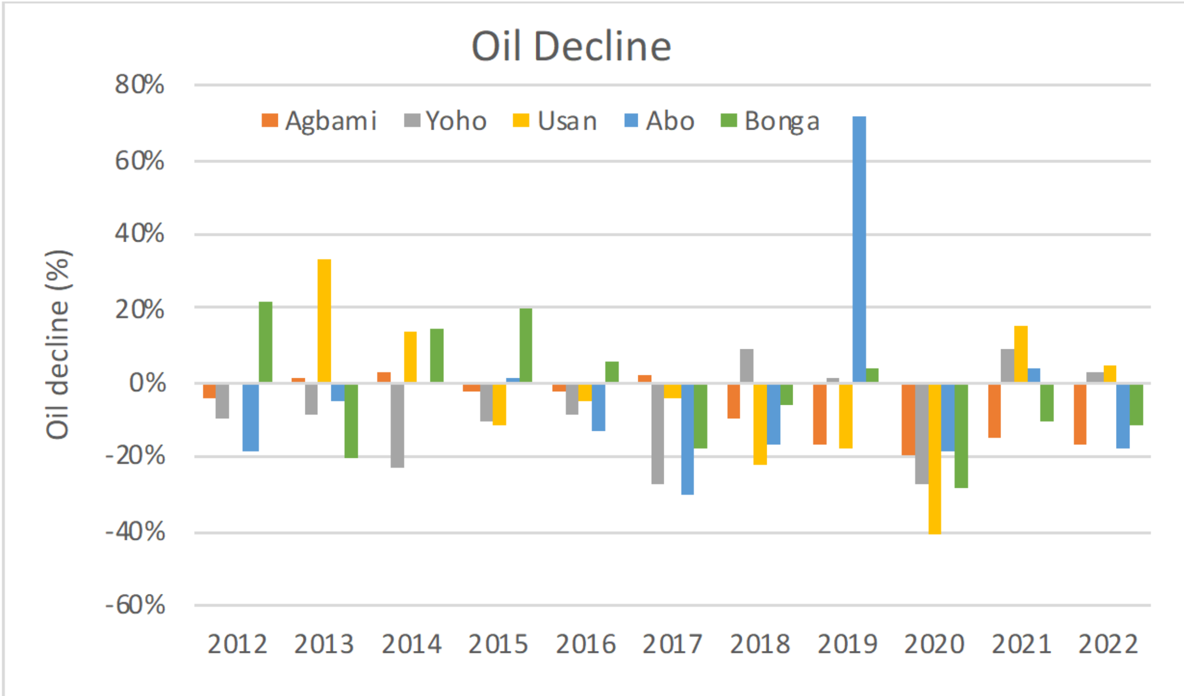


***Source**: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/.*

***Note**: Gas flaring for the five offshore assets is shown in million cubic meters per day (MMm^3/d) as stacked bars (left axis) and as percentage of Nigeria's total flare rate (blue line) on the right axis.*

In Figure 5, the annual average oil decline rates of the five assets are shown individually for the period 2012-2022. The assets show large year-on-year variations, due to production impairments (e.g. equipment failures) and subsequent repairs and new oil development activities. In 2020, all five assets showed a simultaneous oil decline, in response to the measures taken when oil prices collapsed due to global over production of oil, and subsequently oil demand was impaired following the Covid-19 outbreak.[7] From 2012 to 2020 there is an overall trend towards higher negative oil decline rates. In 2020 the combined annual oil decline of the five assets was the highest (26%) and this coincided with lower gas flaring. In 2022, the five assets had the second highest combined oil decline of 10.4%, mainly due to the impact of production declines in Agbami and Bonga assets.

Figure 5*: Oil decline of the five super-emitters reviewed.*



Source*: authors' illustration based on oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

Note*: Annual oil decline rates for the five assets reviewed show large variations, both positive (increased oil production compared to the year prior) and negative (reduced oil production compared to the year prior).*

The individual assets reports describe in detail how oil production and gas flaring trends are interrelated. Two parameters have appeared to be important in describing these relationships: flare intensity (as mentioned above) and flare variability. Flare variability is estimated by dividing the peak flare gas rate by the average gas rate in a given month. For a constant flare rate (i.e. no variability), the ratio between peak and average rates equals 1. During periods of stable operations, the peak-to-average ratio is a factor between 2 and 3. A

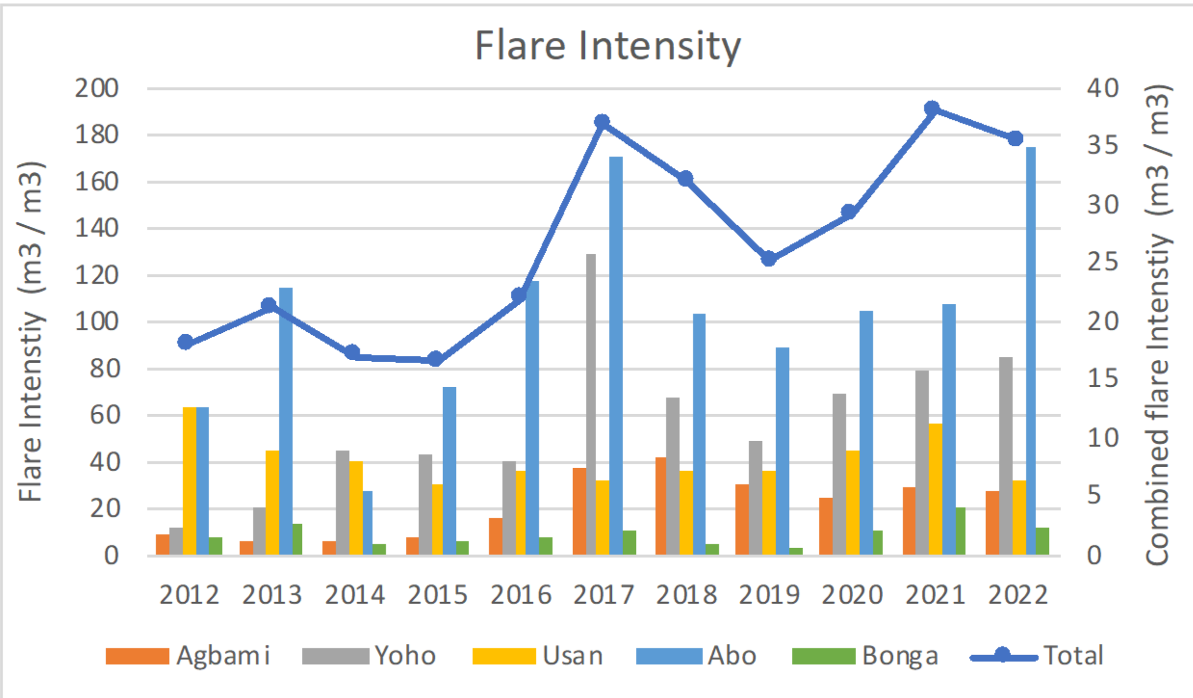
[7] Africa Oil and Gas Report, "How OPEC+ cuts have sliced deep into Nigerian crude output", 17 June 2021; https://africaoilgasreport.com/2021/06/in-the-news/how-opec-cuts-have-sliced-deep-into-nigerian-crude-output/.

flare variability factor of 5 or higher is indicative for increased instability in operational performance.

Flare intensity is a measure of operational quality and production efficiency, as it depicts how much gas is wasted per barrel of oil produced. The flare intensity performance for the individual five assets and their combined performance is presented in Figure 6. It is remarkable that this flare performance measure varies significantly for each of the five super-emitters. Abo, the smallest oil producer among the five assets, shows consistently year-on-year the highest flare intensity. On the contrary, Bonga that has gas evacuation infrastructure connecting the asset to the NLNG facility, has consistently the lowest flare intensity.

As mentioned above, the overall flare intensity trend is rising for the portfolio of these five assets. Yoho shows the most annual variation in flare intensity, which has been investigated and described in the Yoho asset flaring report.

***Figure 6**: Gas flaring intensity of the five super-emitters reviewed.*



***Source**: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

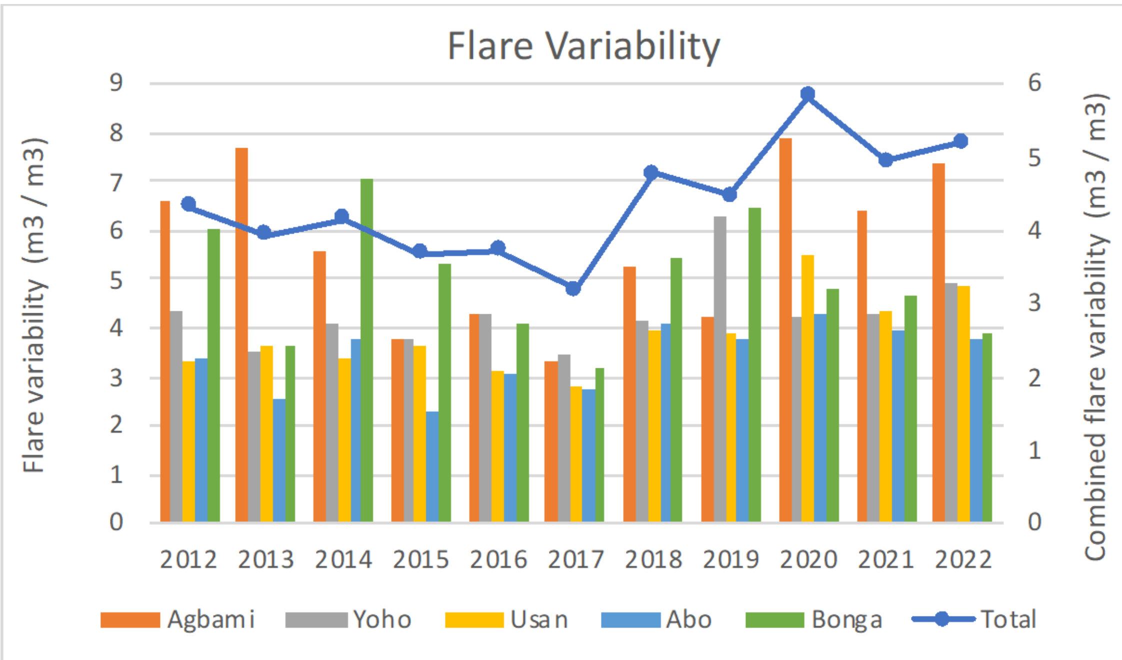
***Note**: Gas intensity (in m^3/ m^3) for the five offshore assets is calculated by dividing annual average gas flare rates in cubic meters per day (MMm^3/d) by oil produced in cubic meters (m^3) per day, shown in bars (left axis). The flare intensity of the five assets combined is shown by the blue line (right axis).*

The flare variability performance for the individual five assets is presented in Figure 7. Of the five assets evaluated, Agbami has overall the highest flare variability, and Abo the lowest. **Flare variability indicative for the severity and frequency of short duration production upsets**. Therefore, this measure is particularly sensitive to identify process trips and reactive emergency shutdowns, that are related to overall topsides process stability. **Longer duration failures and assets that are not repaired (such as e.g. flash gas compressors) show as continuous (i.e. 'routine') flaring and are identified by flare intensity**.

Therefore, it can be concluded that Abo's flaring is predominantly due to long term unavailability or impairment of its gas compression and/or gas reinjection facilities. Agbami on the other hand, appears to flare more significantly due to process trips and production upsets. Despite the differences in relative contribution of the different causes of flaring, the persistent problems to process gas produced results in continuous (i.e. 'routine') flaring for each these five super emitters.

This analysis has been supplemented with an assessment of the fraction of gas flared due to routine flaring versus non-routine flaring (i.e. due to process trips). The results of this assessment are presented in Figure 8.

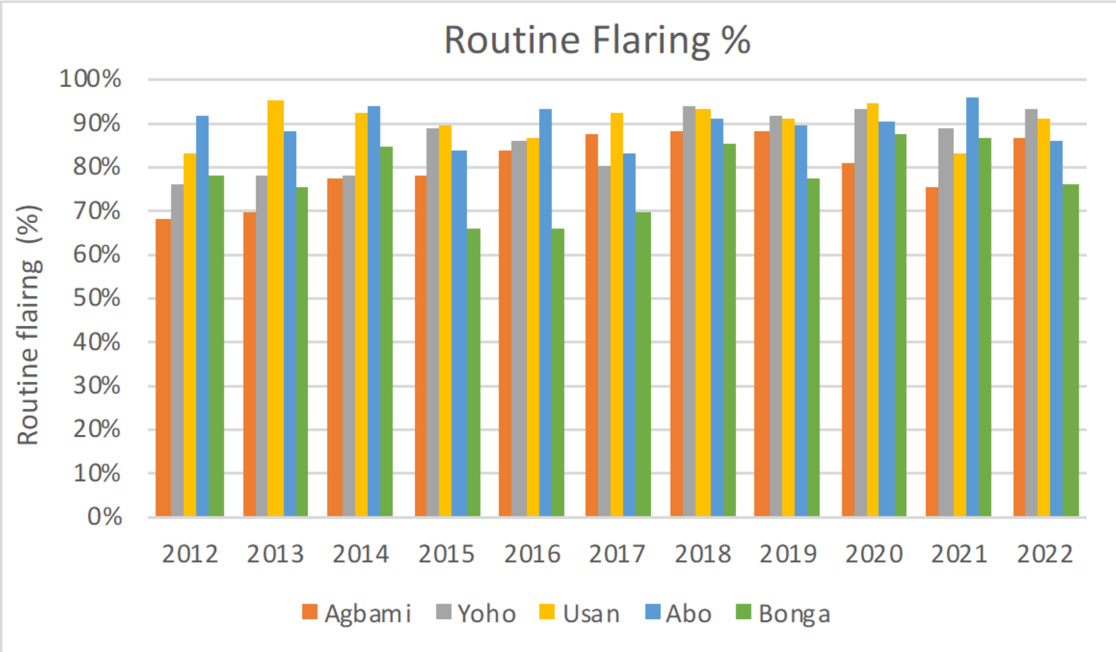
Figure 7*: Gas flaring variability of the five super-emitters reviewed.*



Source*: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

Note*: Gas variability (in m^3/ m^3) for the five offshore assets is calculated by dividing monthly peak gas flare rates in cubic meters per day (MMm^3/d) by monthly average gas flare rates in cubic meters per day (MMm^3/d), and averaging these for any given year shown in the graph.*

Figure 8: *Routine gas flaring as a percentage of total gas flared.*



Source: *authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

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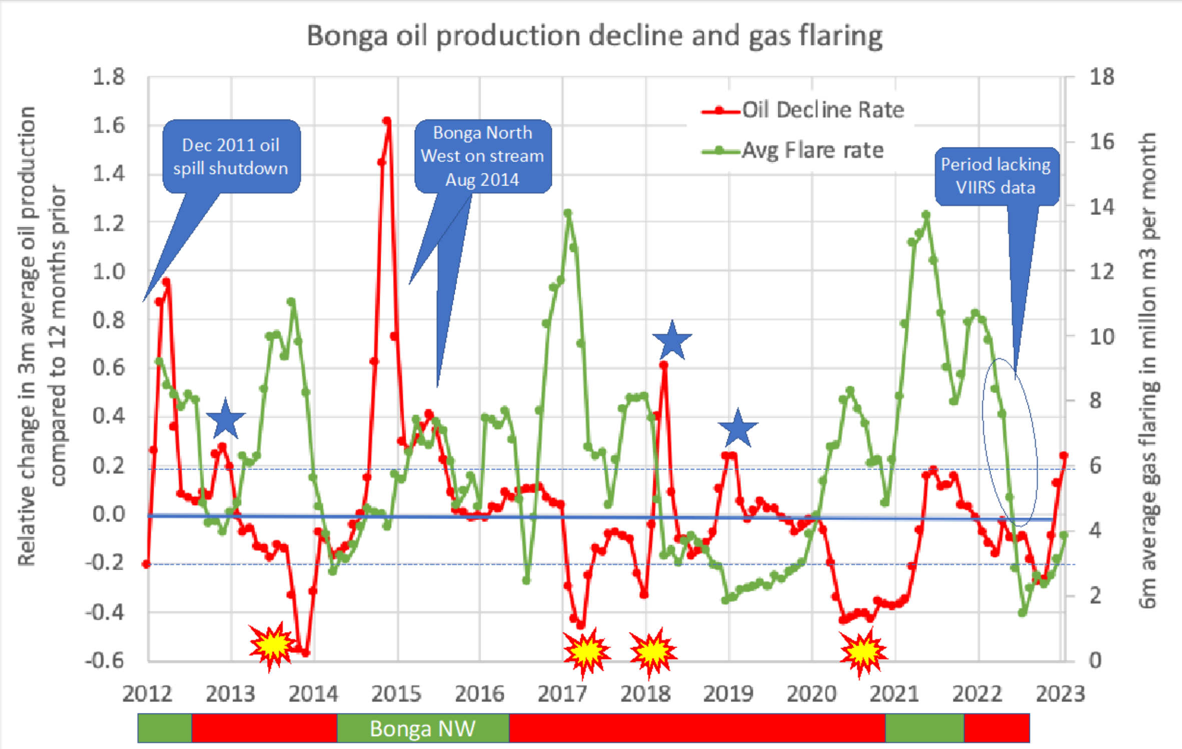
Further to the observations of asset performance identified from flare intensity and flare variability, the above graph (Figure 8) shows that Abo indeed has the highest percentage of routine flaring and Agbami the lowest. Bonga shows a larger contribution to gas flaring from oil process induced instabilities in 2015 to 2017. However, it appears that these process difficulties have gradually been overcome (mostly) and routine flaring has increased instead.

While the above analysis of flare variability (**flaring for safety**) and flare intensity (**flare to produce**) provides a mechanism to distinguish the different types of flaring, there is a third aspect that is a root cause for excessive flaring: when oil production rates are in excess of stable reservoir deliverability rates, much more gas and water are being produced, resulting in significant increases in process trips, low well head pressures, slugging well performance, and thus higher flare variability. In addition, oil decline rates are also negatively affected due to declining reservoir pressures, reservoir gas and water coning and cusping, and thus higher flare intensity. Therefore, **exceeding stable reservoir deliverability rates increases natural gas flaring significantly**. This is illustrated in the detailed asset flare performance analysis reports, such as for Bonga, see Figure 9.

Figure 9: Bonga flare trend compared with monthly averaged oil decline rates



***Source**: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx. Graph obtained from Bonga asset flaring performance report.*

***Note**: Flaring and oil decline rates are mostly positively correlated (as shown by the horizonal red bars below the graph). There are three periods where oil decline rates and flaring are negatively correlated (i.e. higher oil production and higher flaring coincide) as shown by the green bars. The latter generally happens when new oil production comes on stream, such as the Bonga North west wells that started producing from August 2014 onwards. Oil decline rates have been calculated as 3-month moving averages based on oil rates 12-months prior.*

Bonga's performance shows consistently that when flaring increases oil decline rates also increase (yellow stars), and vice versa that when flaring decreases oil decline rates also decrease (blue stars). Exceptions to this trend occur when new oil comes on stream, such as from Bonga Northwest in August 2014. This implies that **oil production rate targets should be complemented by maximum flare rate limits to optimize oil production and recovery of reserves**.

With the commitments made by companies to stop routine flaring by 2025 or 2035, there is a concern that routine flaring (in 2022, 76% to 93% for the five super-emitter assets investigated) is categorized by companies as non-routine flaring. This concern is exemplified by companies' own emissions reporting (see Box A in Section 5.2).[8]

[8] See for example Shell's 2021 Sustainability Report, which mentions: "All of Shell's operated assets within the Integrated Gas business already comply with zero routine flaring, as they were designed to gather gas resources to sell and avoid routine

If flaring is done voluntary rather than for safety reasons, i.e. **if assets 'flare to produce', this should be considered routine flaring**. For example, the voluntary flaring at Bonga in 2021 due to delayed repairs should be categorized as a case of routine flaring (see Bonga asset flaring report). With companies' public commitments to stop routine flaring there is a risk that these companies become compliant to their own commitments by using definition loopholes to requalify routine flaring into non-routine flaring. Stringent flaring definitions and verification processes are recommended. Independent flare measurements, such as from satellite data, are an indispensable tool for regulators and other third parties to verify that flare emission reduction initiatives indeed result in result in actual reductions.

4. Benchmarking methods for gas flaring performance

There are various methods that can be applied to use flaring as a measure to compare production performance and operational quality among assets. Some of these methods are particularly useful to determine when the oil production process becomes too inefficient (in view of the volume of gas wasted per incremental barrel of oil produced), that it is better to redevelop the field as a gas field as this provides more overall value.

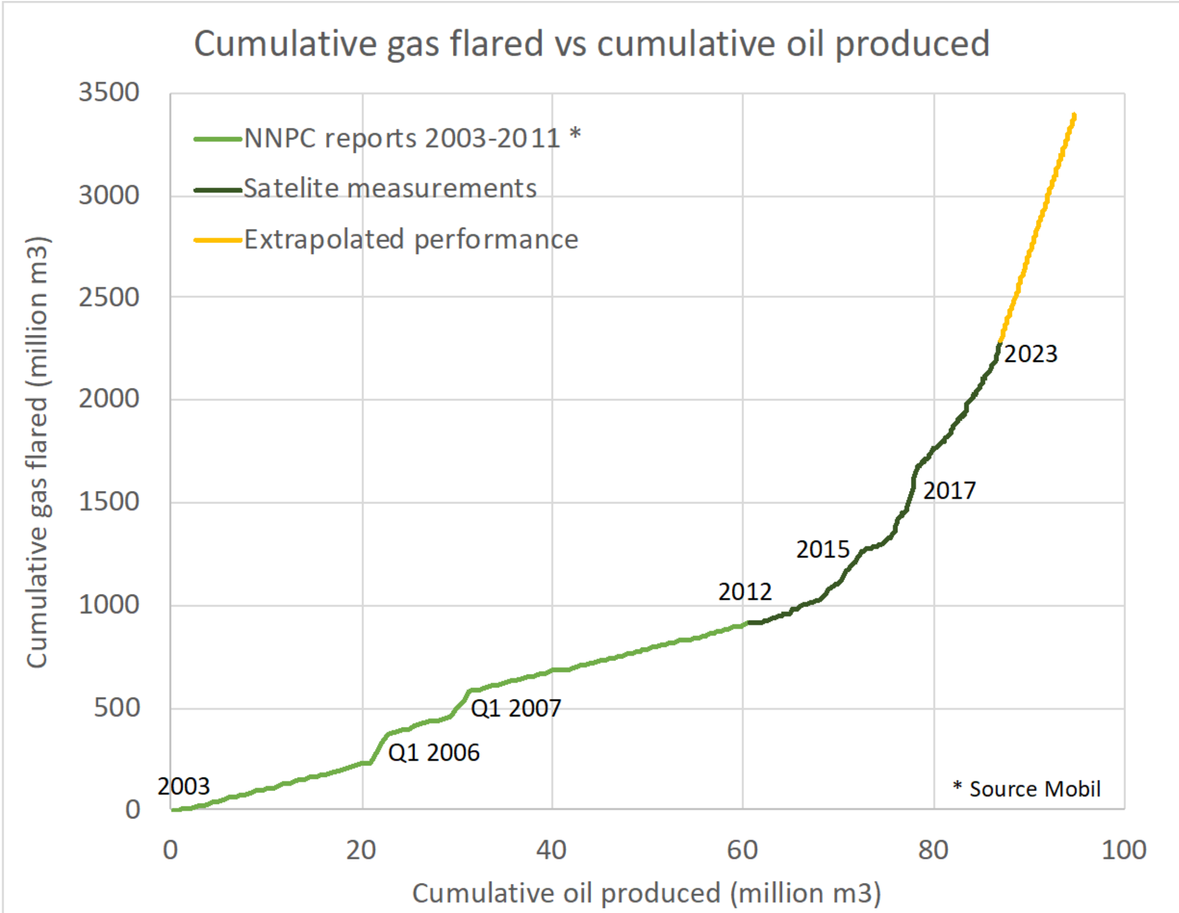
Figure 10 depicts a graph that displays for Yoho asset the cumulative gas volume flared (on the y-axis) against cumulative oil produced (on the x-axis). The steeper the curve, the more gas is flared per volume of oil produced (i.e. the higher the flare intensity). The curve for Yoho field shows that in the last five years (2018-2022), Yoho has recovered 8.7 million m^3 of oil (10% of its total oil volume recovered to date), yet flared 600 million m^3 of gas (27% of its total gas volume flared to date). Yoho's flare intensity in the last five years was three times the average flare intensity during its total field life. If we extrapolate current flare trend (i.e. assume recent flare intensity does not increase further), Yoho field could yet recover an additional 8.4 million m^3 of oil (8.9% of ultimate recovery) but would flare a further 1,174 million m^3 of natural gas in doing so, i.e. 35% of its total volume flared over field life (2003 – 2031). Yet, if future flare intensity continues to increase, it would worsen the amount of gas flared for the marginal oil volume yet to be recovered. The key question is: when should oil production be discontinued, because the amount of gas flared is considered too excessive.[9] Yoho field is notably scheduled to switch from an oil development to a gas development by deploying Nigeria's first Floating Liquefied Natural Gas (FLNG) facility. [10]

flaring." This implies that as long as assets were originally designed not to flare, any flaring from such assets is 'not routine', even if gas handling facilities structurally underperform and cause continuous flaring.

[9] Extract from Etienne Romsom & Kathryn McPhail, "Nigeria's super-emitter flares - an evaluation of trends and causes of natural gas wastage - Yoho Facilities and FSO", March 2023.

[10] Argus Media, "Nigeria to use FLNG for depleting oil field", 4 March 2021; https://www.argusmedia.com/en/news/2192921-nigeria-to-use-flng-for-depleting-oil-field.

Figure 10: *The cumulative flaring curve shows the amount of gas flared for the oil volume (yet to be) recovered*

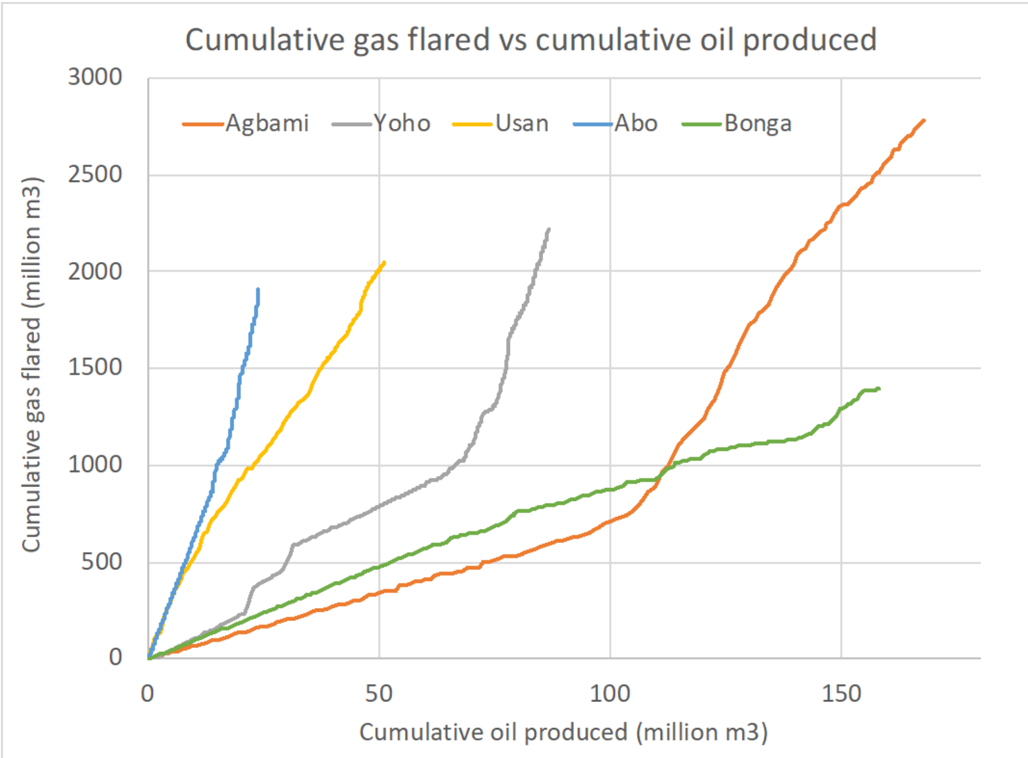


Source*: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

Another aspect of reviewing flare performance, is the comparison of gas flaring between different assets, i.e. which of the assets has a better performance? The challenge is to determine a methodology and metric that achieves such a comparison on an equitable and just basis. Figure 11, 12 and 13 present three such options to compare cumulative flaring performance applied to the five offshore assets investigated, based on: a) cumulative oil volume produced (Figure 11), b) fraction of ultimate recovery produced (Figure 12), and c) number of years of production (Figure 13).

Depending the metrics used for the flaring comparison, the comparison outcome can differ significantly as shown by the Figures below. In Figure 11, it would appear that the flare performance of Yoho is worse than Agbami: at a certain amount of cumulative oil produced, Yoho flared consistently more than Agbami. However, Figure 12 shows that when normalized for field size (i.e. ultimate recovery), Agbami flared more than Yoho. The same observation holds when comparing flare volumes normalized for time, i.e. years of production, as shown in Figure 13, Agbami flaring performance is worse than Yoho.

Figure 11: Cumulative gas volume flared as a function of cumulative volume of oil produced



Figures 11,12, 13 source*: authors' illustration based on VNF data from Payne institute, Colorado School of Mines https://payneinstitute.mines.edu/eog/viirs-nightfire-vnf/ and oil data from NNPC https://nnpcgroup.com/Public-Relations/Oil-and-Gas-Statistics/Pages/Annual-Statistics-Bulletin.aspx (accessed February 2022).*

Note*: Three representations to compare cumulative flaring performance of assets, based on: a) cumulative oil volume produced, b) fraction of ultimate recovery produced, and c) number of years of production.*

Figure 12: *Cumulative gas volume flared as a function of fraction of reserves produced*

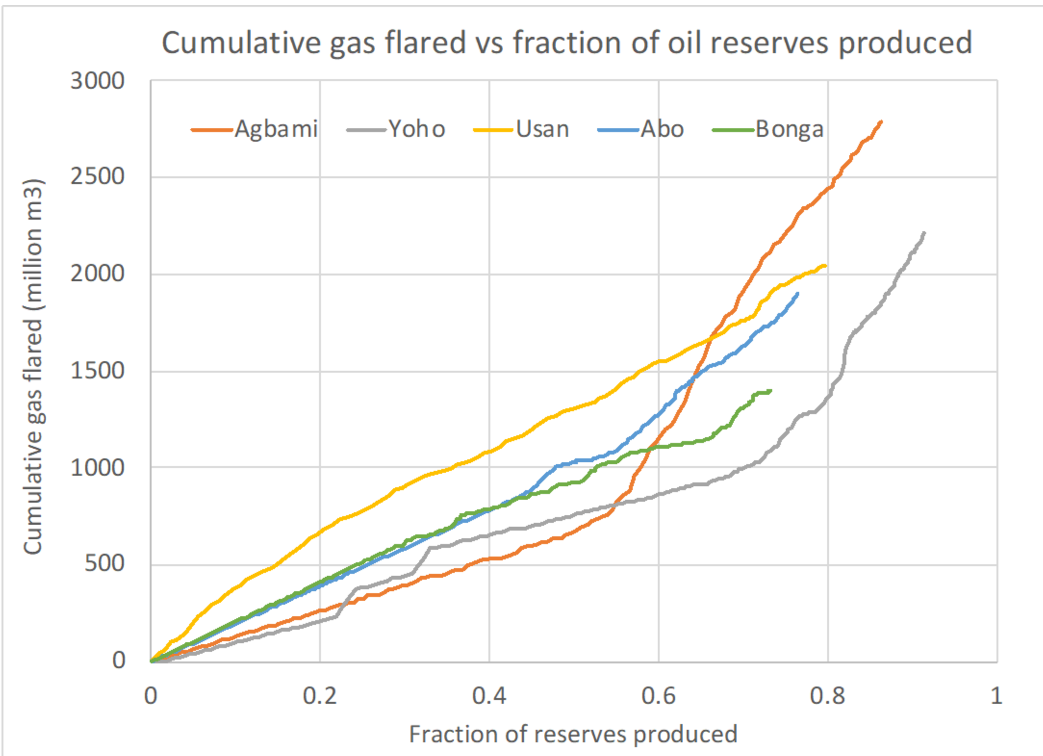


__Figure 13__: Cumulative gas volume flared as a function of cumulative volume of oil produced

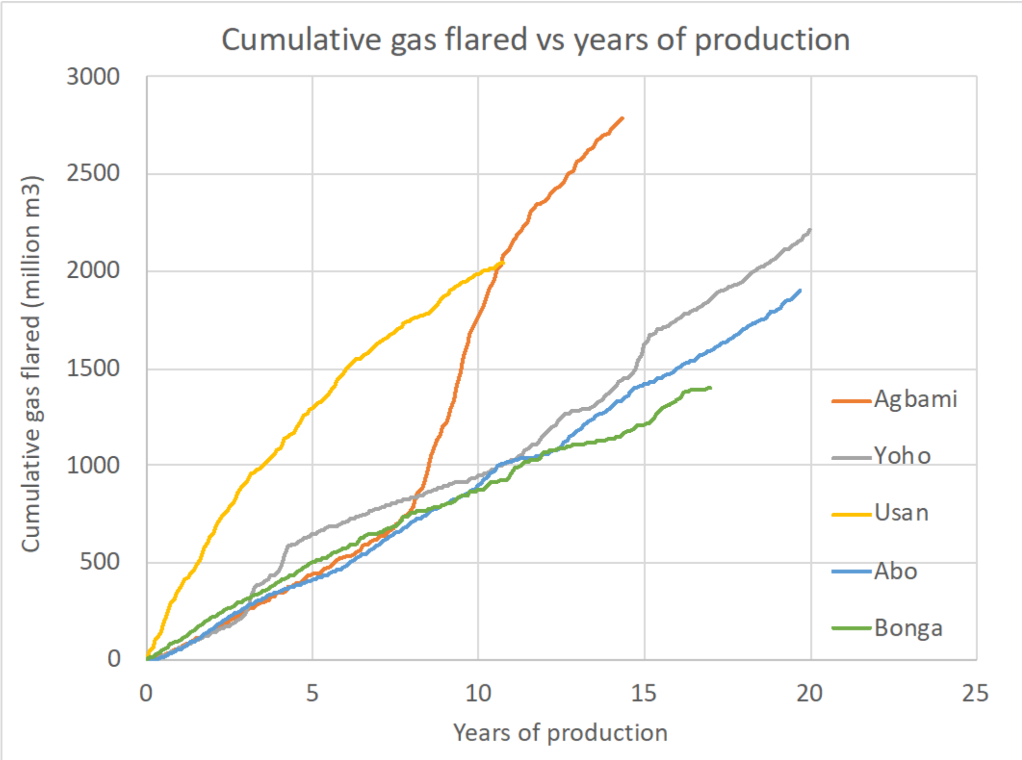


Table 2 shows the various asset ranking outcomes based on flaring performance evaluation for each of the three metrics shown in Figures 11, 12 and 13, respectively.

__Table 2__: Gas flaring performance evaluation based on different metrics (1 = highest flaring; 5 = lowest flaring)

Gas flare performance ranking based on the three metrics	Cumulative flare volume vs cumulative oil produced	Cumulative flare volume vs fraction of reserves produced	Cumulative flare volume vs duration of production
Agbami	4	1	2
Yoho	3	4	3
Usan	2	2	1
Abo	1	3	4
Bonga	5	5	5

__Note__: Asset ranking based on gas flaring performance highly depends on the metric used for the evaluation.

The metric that assesses flaring performance based on the 'Cumulative flare volume vs cumulative oil' intrinsically assumes that larger fields are expected to flare more than small fields. Hence, a key question is if this assumption is justified. This is not necessarily the case:

- The amount of gas flared does not scale with field size, but depends on the design of oil and gas processing facilities and quality of operations.
- Many of Nigeria's gas flaring super-emitters are smaller sized fields or field that produce at low oil rates, further supporting the observation that flaring does not scale with oil production rate.
- Fields with larger ultimate recoveries generally have improved economies of scale, allowing for more elaborate process facilities, such as multiple process trains providing redundancy in case of equipment failures, and multi-stage gas compression to capture also low-pressure gas and avoid flaring.
- Other than field size, larger ultimate recoveries are often the result of better-quality reservoirs. Reservoirs with higher recovery efficiencies generally have more benign production behavior, i.e. less pressure depletion and less gas and water production, which should contribute to lower flaring volumes.

Although flare intensity (volume of gas flared relative to the volume of oil produced as shown in Figure 11) is a useful metric to determine the efficiency in oil recovery as a function of the amount of gas wasted through flaring, and thereby can assist when late life oil production should be halted, it is a less useful metric to compare flaring performance between assets. An alternative measure in which flaring performance is normalized for field size, compares flaring performance across assets based on the cumulative volume of gas flared as a function of the fraction of ultimate oil recovered, shown in Figure 12.

However, the approach in Figure 12 may over-emphasize the contribution of early field life performance when oil rates are generally high and flaring is lower. For example, Agbami produced 55% of its oil ultimate recovery at plateau rates, before reservoir performance and process operations started to impact gas flaring performance negatively. Consequently, at 55% of ultimately recovery produced, Agbami asset was the best performing asset (i.e. lowest flaring) among the five assets. Oil production for Yoho on the other hand, already came off-plateau when it had reached 20% of its oil ultimate recovery.[11] Consequently, Yoho had a larger fraction of its oil recovery under more challenging process conditions than Agbami. In a like-for-like comparison, Agbami asset would be expected to flare less than Yoho.

The method depicted in Figure 13, whereby the amount of gas flared is represented as a function of time (i.e. number of years of production) is a better metric to compare flare performance across assets than either of the other two methods discussed and shown in Figure 11 and 12. The flare volume versus time method demonstrates that Agbami asset

[11] The fraction of oil ultimate recovery produced at plateau rates is due to a combination of factors, including reservoir quality (higher recovery efficiency fields generally have a longer plateau production period) and the balance between reservoir delivery-rate capacity (i.e. reservoir drive) versus production capacity (i.e. a combination of number of wells and size of the process facilities).

flared 2.8 billion m^3 in 14.3 years (on average 194 million m^3 per year), while Yoho asset flared 2.2 billion m^3 in 20 years of production (on average 111 million m^3 per year), see Figure 13.

The ability to absorb and breakdown emission chemicals over time is an important aspect in global warming and air quality. Therefore, emissions measures that are normalized for time better reflect the amount of harm caused. The metric 'flare volume versus time' (i.e. flare rate) is therefore of greater relevance to the impact of natural gas flaring on climate change and air quality (i.e. Social Cost of Atmospheric Emissions, SCAR than the other two measures).[12]

Finally, 'flare volume versus time' measure can also be applied to compare flaring from non-oil producing assets, such as gas fields, gas processing plants, chemical plants and refineries, and has thus a larger range of applicability.

Therefore, **the recommended metric to compare flaring performance between assets is the cumulative volume of gas flared versus the period of gas flared.**

As a secondary measure, for assets that have similar flare rates, the flare intensity measure (cumulative flare volume vs cumulative oil produced), can be a useful metric to further compare and rank upstream assets on their flaring efficiency.

5. Nigeria country assessment: solutions for super emitters

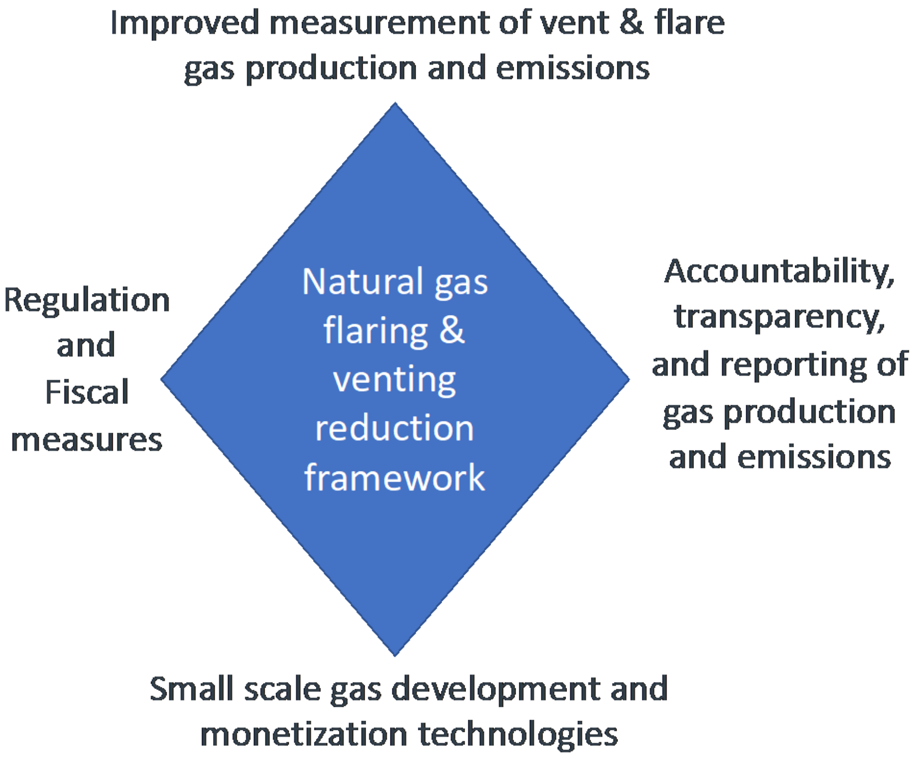
Having developed and assessed methodologies for comparing and priority ranking of natural gas flares in the previous section, this section discusses readily implementable solutions to reduce the emissions of routine gas flares.

The Phase I report found that Nigeria has been very successful in reducing gas flaring from 21.4 Billion cubic meter (Bcm) in 2005 to 6.6 Bcm in 2021. Yet, there is still progress to be made, particularly from its 18 "super-emitters". Globally, there are 300 super-emitters that have been identified based on their persistent high rate flaring of at least 5.7 MMscf/d on average per flare during 2017 to 2021.

Solutions exist today. The Diamond Model (Figure 14) provides a framework for combining four elements: (1) improved measurement of flare gas production and emissions; (2) accountability, transparency, and reporting of gas production and emissions; (3) gas development and monetization technologies; and (4) enhanced regulation and fiscal measures. These four elements are interrelated, and implementation of each element can benefit the effectiveness of the other elements. This public-private collaboration provides a strategy to capture both the economic and the social value from hydrocarbon gas flaring and venting.

[12] See references in footnotes 4 and 5.

Figure 14: The Diamond Model: Integrated solutions to reduce gas flaring and venting



***Source**: authors' illustration*

5.1 Solution 1. Measurement using satellite technologies: support for an effective regulatory framework

Reliable assessment of emissions from flaring and venting can help regulators in several ways.

Improves understanding of how much natural gas is emitted and lost through these practices and helps to determine the basis for assessing compliance with restrictions on emissions volumes and taxes and/or penalties that may be levied (see Section 5.4).

Accurate and timely data are essential for design and verification of efficient regulations. Natural gas that is flared and vented is seldom metered and is generally not measured. As a result, data are sparse and estimates often unreliable. Yet remote-sensing technologies are increasingly capable and accurate in monitoring and measuring emissions, particularly those from individual gas flares. The VIIRS Nightfire (VNF) satellites undertake multiple satellite overpasses daily, which enable daily flare measurements. Since 2012, these data are published which enables gas flaring trends to be measured over time.

Satellite measurements have several advantages. There is no need to invest in local meters, to calibrate these meters, or to gain access to sites with flaring and venting operations.

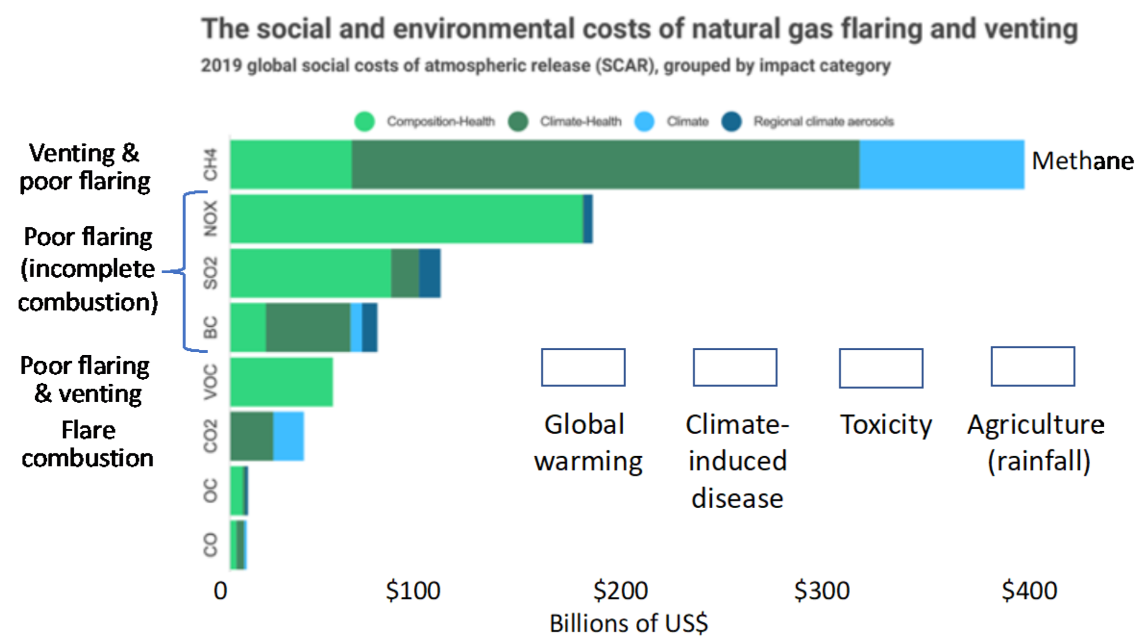
Instead, data aggregation and processing can be done remotely. Satellite data provide an independent and objective assessment of emissions and are generally in the public domain, which promotes transparency. If oil and gas operators want to challenge satellite data with their own metered data, they should engage recognised third parties to verify their measured amounts of gas flared and vented.

Provides reliable estimates on the volumes of individual chemicals emitted to determine the SCAR of each flare and vent.

VNF satellites measure flare rates through the radiation emitted from the flaring combustion processes. VNF therefore measures only the fraction of natural gas that is fully combusted. Many flares do not reach a 100% combustion target where all hydrocarbons are destroyed. VNF measurements may therefore underestimate actual gas flare rates. If flare gas is not fully combusted, a range of chemicals is produced that are toxic to human health, as well as affecting air quality and climate. See Figure 15 below.

Estimates of the **Social Costs of Atmospheric Release (SCAR)** by Romsom and McPhail are based on a methodology developed by Shindell.[13] This methodology integrates the impacts of atmospheric chemical releases on climate, agriculture (due to regional changes in water cycles induced by aerosols), toxicity (air quality) and climate induced (communicable) disease into a single measure from these four key areas.[14] These are represented in the four colours in Figure 15 below.

***Figure 15**: SCAR impact of global flaring and venting by individual chemical emitted*



***Source:** illustration by UNU-WIDER https://www.wider.unu.edu/publication/reducing-wasted-gas-emissions-opportunity-clean-air-and-climate (permission obtained).*
***Note**: Methane has the largest SCAR among the various chemicals emitted from natural gas flaring and venting.*

[13] See references in footnotes 4 and 5.

[14] McPhail and Romsom, UNU-WIDER Blog, "Reducing wasted gas emissions is an opportunity for clean air and climate", October 2021; https://www.wider.unu.edu/publication/reducing-wasted-gas-emissions-opportunity-clean-air-and-climate.

Figure 15 also makes it clear that among the eight chemicals emitted by flaring and venting, methane (CH_4) has a far greater social cost than does carbon dioxide (CO_2). So, reducing methane emissions by curbing gas flaring and venting provides a fantastic opportunity to reduce the negative impacts on human health as well as on global warming. [15]

Helps determine if the flare is operating within its design envelope, i.e. if the targeted destruction efficiency of 98% is being met and SCAR minimized.

Flare quality is seldom measured, and regulatory frameworks to oversee flare quantity and quality are often non-existent, inadequate or not enforced. Regulations typically focus on limiting volumes without considering flaring performance standards. The social cost of flaring (SCAR) increases immensely when the quality of the flaring process does not meet its 98% destruction efficiency standard. A recent paper confirms our findings of systemic under-reporting of atmospheric emissions from flares. The ERL paper addresses emissions in the Mexican oil and gas sector and states that "*roughly 70% of CH_4* [i.e. methane] *emissions in the offshore study region are related to flaring, with the other 30% classified as venting*". This work strengthens our assessment that poor flaring (i.e. incomplete combustion) is the cause of significant release of SCAR causing chemicals, including methane. Most studies do not include flares as a major source of methane releases as the common assumption is that methane is burned up by the flares. We believe that this is a significant omission.

It is now increasingly possible to use VNF data to assess flare quality. Initial analysis indicates that the VIIRS short wave detectors in the visible light spectrum are more impacted by flare quality (smoke) than those in the infrared spectrum. In the case of poor flaring, this causes the registered flare temperature to be below the expected range for flares. Another effect of poor-quality flaring is dispersion, resulting in a larger black-body area estimate than expected, based on the flaring rate. Both temperature and black-body area estimates are measure by VNF, allowing potential poor-quality flaring events to be identified.

Starting in 2012, when VNF data were first published, these satellite measurements show that all five Nigeria offshore super emitters evaluated have been producing under routine and continuous gas flaring (see Figures 4 and 8 above). These findings are all the more striking since each of these five facilities was designed to be operating under 'zero routine flaring' standards.

Identifies potential super-emitter flares and vents early for corrective action.

The VNF satellite data can identify global super-emitters – the top three percent of all global flares that burn more than 42% of all gas wasted from the 9,699 flares with rates measured in 2021. Given their disproportionately large environmental and economic impact, the occurrence of super-emitter flares should be avoided and penalties imposed for assets not meeting flare quality standards.

[15] Hicklin and McPhail, CGD Blog, February 2022; https://www.cgdev.org/blog/practical-proposal-methane-2022-climate-pledges-action.

Each of the five assets evaluated in this study is a global super emitter. Satellite data enable Regulators to identify and focus on these super-emitter flares. Half of Nigeria's 18 super-emitters are located offshore. Satellite measurements provide critical data on asset performance and compliance for remote assets that otherwise would be very difficult to obtain independently.

The satellite data also show that all five assets were able to reduce flare rates for prolonged periods of time when operators focus on quality of operations and the operation policies prioritize low flaring. It is striking that these same periods of reduced flaring coincide with significantly more stable oil production. An important conclusion is that **low flaring is indicative of operational control that benefits oil production as well as lower emissions**. The assumption that flaring is necessary to grow oil production to meet demand is not borne out from the flare evaluation assessments in Nigeria.

Operators should focus on maintaining stable oil production, by limiting off-take rates within reservoir delivery limits. A key measure that optimizes off-take rates is to limit natural gas flaring. In addition to oil production targets, producing assets should simultaneously be constrained by keeping natural gas flaring below an absolute limit. Good technical performance optimizes oil recovery, while at the same time minimizes the negative environmental impact by reducing emissions.

A clear definition of routine flaring is needed that reflects the policy: "***operators shall not flare to produce***". Routine flaring should be defined based on quantifiable measures such as, flare rate continuity, variability and intensity. When upper limits of flare standards are exceeded, oil production must be reduced to keep flaring rates within limits. Hence, flare volumes should be reported by license operators using absolute flare rate measures. Satellite data enable Regulators to verify the reported volumes of gas flared and investigate asset performance further in case of deviations, or if flare measurements are outside of allowable ranges.

5.2 Solution 2. Accountability and Transparency: corporate disclosure and stakeholder audits

Global institutional investors and increasingly, Central Banks, find that a lack of corporate disclosure and transparency of emissions exposes investors and regulators to significant risks. Investors are under pressure due to the associated impact on climate and human health. Financial regulators are focussing on the impact of material climate risks to the financial sector from 'stranded assets'.

Investors and financial regulators are now focused on addressing this gap, for example with the standard framework of the TCFD which includes metrics on upstream hydrocarbon flaring and venting. The TCFD is considering requiring mandatory disclosure of climate and transition risk in companies' public annual filings to provide 'decision-useful' information to investors and financial regulators. Mandatory company reporting produces comparable data which enable benchmarking, peer pressure, performance improvement, and an assessment of climate and health risks.

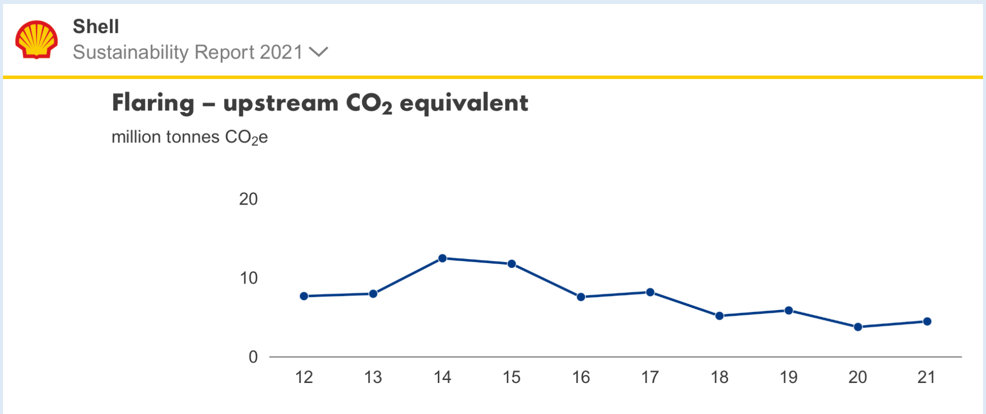
Under-reporting of flaring and venting appears to be a systemic issue in the oil and gas industry. Third-party verification for atmospheric emissions is absent. Without reliable data, the development of flaring and venting reduction solutions is being hampered. Box A below shows the variation in reporting by oil and gas companies on their emissions performance.

BOX A: Corporate reporting challenges of flaring emissions

There is a significant variety in the level of disclosure by oil and gas companies on their emissions performance. Emissions data, when disclosed, are presented in aggregated form, making it difficult to analyse the causes for the overall trend. Furthermore, there is lack of transparency on the variability of emission performance across companies' assets. Total S.A., Shell, BP, ENI and Chevron do annually report natural gas flaring in their corporate reporting, but formats vary. ExxonMobil does not report flaring volumes explicitly. Compared to its peers, Chevron has a more detailed reporting that includes flaring intensity and absolute flare volumes for the most recent five years. Its upstream flaring equity emissions for CO2 are reported in tonnes and for methane and other greenhouse gases in tonnes as well as tonnes CO_2-equivalent (CO2e). Gas flared volumes are reported in MMscf.[16] This contrasts with BP that provides a single number for total hydrocarbons flares in tonnes compared to the year prior.[17]

Shell reports that flaring of gas in its upstream and integrated gas businesses contributed around 7% to its overall direct greenhouse emissions in 2021. Shell reports its flaring performance annually in in its sustainability report in graphical format as shown in Figure A-1 below.[18]

***Figure A-1**: Shell gas flaring performance trend*



***Source**: Shell Sustainability Report 2021*

Shell further reported the following:

> *In 2021, around 17% of greenhouse gas emissions from flaring occurred at facilities where there was no infrastructure to capture the gas (down from around 24% in 2020). Overall flaring increased to 4.5 million tonnes of carbon dioxide equivalent (CO_2e) in 2021 from 3.8 million tonnes of carbon dioxide equivalent in 2020. Around 60% of flaring in our Upstream and Integrated Gas facilities in 2021 occurred in assets operated by the Shell Petroleum Development Company of Nigeria Limited (SPDC) and Shell Nigeria Exploration and Production Company Limited (SNEPCo). Flaring from*

[16] Chevron, 2021 corporate sustainability report; https://www.chevron.com/-/media/shared-media/documents/chevron-sustainability-report-2021.pdf
[17] BP Sustainability Report 2021; https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/sustainability/group-reports/bp-sustainability-report-2021.pdf
[18] "Shell Sustainability Report 2021; https://reports.shell.com/sustainability-report/2021/achieving-net-zero-emissions/managing-greenhouse-gas-emissions/flaring.html.

SPDC-operated facilities increased by around 5% in 2021 compared with 2020. Flaring at SNEPCo-operated facilities increased by 160% in 2021 compared with 2020. This was because repairs to a flexible joint on the gas export riser on the Bonga deep-water floating production, storage and offloading (FPSO) facility took longer than planned. A large amount of gas was therefore flared while the FPSO continued to produce oil.

A key area of challenge for oil and gas companies has been their reluctance to report on emissions from assets in which they have a participating interest but are operated by other companies. Some companies, such as ENI are partially responding to this challenge, by reporting some measures on an equity basis. For example, for net carbon footprint ENI reports[19] as follows:

> *"Scope 1: GHG emissions from sources attributable to the company's assets (e.g., combustion, flaring, fugitive, venting) .....*
> *Eni: the indicator considers GHG Scope 1+2 Emissions from* ***assets operated by Eni and third parties*** *accounted for on an equity basis and net of offsets from Natural Climate Solutions*
> *Upstream: the indicator considers GHG Scope 1+2 Emissions associated with hydrocarbon development and production* ***activities operated by Eni and by third parties****, accounted for on an equity basis (Revenue Interest) and net of offsets from Natural Climate Solutions.".*

In the same report however, Eni reports "*Total volume of hydrocarbons sent to routine flaring*" on the basis of "*Indicators calculated on 100% of data* ***for operated assets***".

The global oil and gas association IPIECA recommends in its Sustainability reporting guidance for the oil and gas industry that oil and gas companies report flaring emissions on the basis of the assets operated, see Figure A-2.[20] However, IPIECA also makes provision for "Reporting beyond your boundary", i.e. reporting of emissions from assets where a company is not the operator, but has an equity interest.

Figure A-2*: Extract of IPIECA guidance on sustainability reporting standards*

MODULES	INDICATORS	OPERATIONAL	EQUITY SHARE	WORKFORCE	CORPORATE
Governance and business ethics	GOV-1: Governance approach				
	GOV-2: Management systems				
	GOV-3: Preventing corruption				
	GOV-4: Transparency of payments to host governments				
	GOV-5: Public advocacy and lobbying				
Climate change and energy	CCE-1: Climate governance and strategy				
	CCE-2: Climate risk and opportunities				
	CCE-3: Lower-carbon technology				
	CCE-4: Greenhouse gas (GHG) emissions				
	CCE-5: Methane emissions				
	CCE-6: Energy use				
	CCE-7: Flared gas				
Environment	ENV-1: Freshwater				
	ENV-2: Discharges to water				
	ENV-3: biodiversity policy and strategy				
	ENV-4: Protected and priority areas for biodiversity conservation				
	ENV-5: Emissions to air				
	ENV-6: Spills to the environment				
	ENV-7: Materials management				
	ENV-8: Decommissioning				

Source*: IPIECA Sustainability Reporting Guidance 2023*

[19] "Eni for 2021 Carbon neutrality by 2050"; https://www.eni.com/assets/documents/eng/just-transition/2021/eni-for-2021-carbon-neutrality-2050-eng.pdf
[20] IPIECA, "Sustainability Reporting Guidance 2023"; https://www.ipieca.org/media/6096/sustainability-reporting-guidance-2023-update-full-pdf.pdf

Another key challenge relates to setting targets for **routine flaring** or reporting only routine flaring (as ENI does) as opposed to total flaring emissions. Routine flaring has been defined by the World Bank[21] as follows:

> "*Routine flaring of gas is flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market*"

If a company is facing equipment outages, such as flash gas compressor failure, but continues to produce and therefore flare excess gas, is this considered 'routine' or 'non-routine' flaring? What if such company now decides that repairing the flash gas compressor is too expensive and continues to flare gas, at what point does the flaring become routine? If a company has made investment to reinject its produced gas, but faces a problem to dispose of all the gas due to lack of well injectivity, compression capacity or reservoir performance, does this qualify as 'routine' or 'non-routine' flaring?

Shell's 2021 Sustainability Report, provides answers to above questions:

> *All of Shell's operated assets within the Integrated Gas business already comply with zero routine flaring, as they were designed to gather gas resources to sell and avoid routine flaring.*

This implies that as long as assets were designed to avoid flaring, any flaring by these assets is considered non-routine flaring, even if the flaring is done voluntary rather than for safety reasons. Following the same logic, the voluntary flaring at Bonga in 2021 due to delayed repairs is considered non-routine, even though this is a clear case of 'flaring to produce'.

With companies' publicized commitments to stop routine flaring there is a risk that these companies use loopholes to requalify routine flaring into non-routine flaring. Stringent flaring definitions and verification processes are recommended.

For the last decade, Total S.A. has been reporting its natural flaring of the assets it operates by providing a table with corporate annual aggregated flare rates (in MM^3/d) for the most recent four years. Recently, it has started to differentiate between routine flaring in addition to total flaring. CEO Patrick Pouyanné in his message from the Chairman and CEO" mentions in the introduction of Total's "Sustainability & Climate 2022 Progress Report":

> *"This vision is not a mirage or greenwashing. It is based on measurable objectives to reduce our greenhouse gas emissions in the short (2025), medium (2030) and long (2050) term, covering our industrial operations (Scope 1+2) and the emissions generated by our customers' use of our energy products (Scope 3). We affirm our ambitious target of a more than 30% reduction in greenhouse gas emissions related to sales of petroleum products (Scope 3 Oil) by 2030 compared to 2015. To that, we add phased targets for reducing methane emissions (50% from 2020 levels by 2025 and 80% from 2020 levels by 2030) to move towards zero methane and an* ***objective of less than 0.1 million cubic meters per day for routine gas flaring at our operated assets by 2025, before eliminating flaring completely by 2030****.*

Total is a founding member of the World Bank's "Zero Routine Flaring by 2030" initiative. Since 2014, the Company has pledged to end the practice altogether by 2030. What is noteworthy is that Total S.A. flare reporting explicitly excludes non-operated assets (i.e. assets in which Total companies have a participating interest and/or equity ownership, but are operated by other non-Total companies or entities).[22] The exclusion of non-operated assets in companies' reporting provides a mechanism for companies to decarbonize their 'books', while hiding the true emissions of their portfolio. The argument that companies use is that they apply this restriction in reporting to avoid double counting, if other operating companies report emissions on a 100% basis. It is apparent that potential confusion on accounting principles can be easily avoided by reporting both operated and non-operated assets at 100% and on participating interest basis. Together with routine versus non-routine flaring, this would expand flare reporting from one single number per year to eight numbers.

[21] The World Bank, "Zero Routine Flaring by 2030 (ZRF) Initiative - Frequently Asked Questions and Answers"; https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#8

[22] Total S.A, "Sustainability & Climate 2022 Progress Report"; https://totalenergies.com/info/totalenergies-publishes-its-sustainability-climate-2022-progress-report

Table A-1: Natural gas flaring reporting categories

Natural Gas Flaring Reporting	Company share Operated	Company share Non-Operated	100% Operated	100% Non-Operated
Routine	own elective flare volumes under own operational control	own elective flare volumes under operational control of others	total elective flare volumes under own operational control	total elective flare volumes of assets with participating interest under operational control of others
Non-routine	own non-voluntary flare volumes under own operational control	own non-voluntary flare volumes under operational control of others	total non-voluntary flare volumes under own operational control	total non-voluntary flare volumes of assets with participating interest under operational control of others
	Own flare volumes under own operational control	Own flare volumes not under own operational control	Total flare volumes under own operational control	Total flare volumes not under own operational control

Even if companies were to follow this recommended practice of more transparent reporting, there continues to be a risk of portfolio greenwashing by disposing high flaring assets to other companies that have less stringent approach to emissions reporting. A distinction ought to be made between actual reductions in emissions and portfolio reductions. Remote measuring of emissions by satellites is an extremely valuable tool to assess flare performance of assets, regardless of transfer of operatorship or ownership.

Transparent company reporting helps to inform regulators as to whether the taxes or fines are charged at levels that reflect the economic and social value of the gas wasted. Transparent reporting of emissions is also an important enabler towards achieving emission reductions to address reputational risk and to improve the social licence to operate.

The Nigeria Extractive Industries Transparency Initiative (NEITI) Act 2007, established a multi-stakeholder organisation. Its purpose is to develop a framework for transparency and accountability in the reporting and disclosure by all extractive industry companies of revenues due to, or paid to, the Nigerian government. It publishes annual audit reports, including on the oil and gas sector. NEITI also reports on gas flaring and flare rate penalties (See Section 5.4). Flare volumes (in 2019 and 2020) reported by NEITI for the five offshore super emitters investigated correspond well with flare volumes assessed in this study.

NEITI can play an important role in further setting standards for companies in their reporting of emissions, and evaluating their emission performance accordingly. As there is currently a significant variety in the level of disclosure and transparency by oil and gas companies on their emissions performance, companies are strongly encouraged to report flaring performance explicitly, and on the basis of absolute metrics, such as amount of gas flared. Earlier NNPC public reporting on oil and gas operations used to include gas production volumes as well gas volumes flared by asset. This was a very useful practice and could be considered to be reintroduced.

Approvals for field development plans should specify maximum flaring limits. Operators need to demonstrate to regulators that they meet the conditions of operations. Reporting should by asset, and include ‘routine’ and ‘non-routine’ flaring, as well as gas flared from own operations and equity interest in assets operated by others. Distinction is needed between actual reduction in emissions and portfolio reductions. Satellite technology can supplement reporting and disclosure to assess flare performance of assets, regardless of transfer of ownership or operatorship.

5.3 Solution 3. Gas monetisation: necessary but insufficient ?

There are many different technologies available to commercialize natural gas. Monetization of associated gas can create new employment opportunities. It often requires commercial and regulatory solutions (see Section 5.4), for example, to grant access rights to gas evacuation infrastructure and/or the right to sell the gas.

Nigeria has a long and well-established track-record in developing natural gas resources. Nigeria LNG (NLNG) was established in 1989, commissioned a decade later in 1999 and expanded rapidly over the next decades[23].

Four of the five offshore assets evaluated were commissioned between 2003-2008, the fifth in 2012. Thus, large scale gas monetization opportunities for associated gas were already available in the form of Nigeria LNG. This particularly the case for Shell, ENI, and Total, as shareholders in NLNG. So it is striking that only one of the assets evaluated, Bonga (commissioned in 2005), was designed to supply associated gas to the Nigeria LNG facility. From the maps in Figures 1 and 2, it is evident that Agbami, Yoho and Usan are all located closer to the NLNG plant than either Bonga or Abo.

Other than Shell, there is no evidence of any commercial assessment undertaken by any of the operators to determine whether offshore associated gas supplies to Nigeria LNG or other gas monetisation facilities would be feasible, including access to third party infrastructure. Notwithstanding the sizeable investments in offshore processing facilities, none of the assets except Bonga included facilities to monetise the produced gas.

In 2007, the President of Chevron International Exploration and Production, John Watson, said that Agbami would reinject all the associated gas that otherwise would be flared. He indicated that a key component of the company's strategy for reducing gas flaring in Nigeria is the company's plans to "produce high quality diesel from gas in its Escravos gas-to-liquids project"[24], with an expected start-up date of 2009. The strategy on gas flaring was set out in 2010 by George Kirkland, Vice Chairman, EVP - Global Upstream and Gas:

"In West Africa, we have several concurrent projects under construction that will significantly reduce gas flaring in the region, extract liquids, deliver domestic gas supply and enable incremental oil production. In Nigeria, Phase 3A of the Escravos Gas Project is expected to come on-line this month (March 2010). The plant has a processing capacity of almost 400 million cubic feet per day and 43,000 barrels a day of liquids. Also in Nigeria, the Escravos Gas-To-Liquids (EGTL) project is expected to start up in 2012. This plant will utilize 325 million cubic

[23] See also Box A in Bonga Flare Performance Assessment Report.
[24] New York Times, "Pressure on Oil Companies grows to end gas flaring in Nigeria", October 29, 2007; https://www.nytimes.com/2007/10/29/business/worldbusiness/29iht-rennig1.1.8090092.html

feet of gas a day and produce 33,000 barrels a day of product”. [25] *This GTL project was part of a 50-50 Sasol Chevron Global Joint Venture established in October 2000 to develop a worldwide gas-to-liquids (GTL) business”.* [26]

Chevron’s significant investments related to gas monetisation projects are set out in Table 3.

***Table 3**: Chevron major projects overview in Nigeria*

Chevron

Upstream Major Capital Projects
West Africa Region – Nigeria

Project	Location	Operator	WI %	C&E $Billion	Peak Prod MBOED	Current Phase	Start-up
Agbami	Nigeria	Chevron	68.2	7.0	250	Production	2008
West African Gas Pipeline	Nigeria to Ghana	Chevron	36.7	1.1	28 (2)	Construction	2010
Nigeria EGP3A	Nigeria	Chevron	40	2.4	109	Construction	2010
Agbami 2	Nigeria	Chevron	68.2	1.9	Maintain 250 Capacity	Construction	2011
Onshore Asset Gas Mgmt	Nigeria	Chevron	40	0.7	21	Construction	2012
EGTL	Nigeria	Chevron	75	5.9	33 (3)	Construction	2012
Usan	Nigeria	Other	30	8.4	180	Construction	2012
Nigeria EGP3B	Nigeria	Chevron	40	2.0	28 (4)	Construction	2012
Bonga SW/Aparo	Nigeria	Other	20 (1)	Refer to operator	TBD	Design	TBD
Olokola LNG Plant	Nigeria	Other	19.5	TBD	TBD	Design	TBD
Olokola Gas Supply	Nigeria	Chevron	40	TBD	TBD	Design	TBD
Nsiko	Nigeria	Chevron	95	TBD	TBD	Evaluation	TBD

(1) Represents a weighted average of Chevron’s interest across multiple blocks.
(2) Represents total processing capacity.
(3) Represents total plant offtake of liquid products.
(4) Represents gas processing capacity and excludes incremental oil production enabled by this project.

***Source**: Chevron Corporation’s 2010 Security Analyst Meeting Appendix Upstream & Gas Projects March 09, 2010 https://chevroncorp.gcs-web.com/static-files/a02d8826-91f4-4050-b6d9-ab1238290504*

Challenged by one investor as to why the company was spending so much on the Escravos GTL project in Nigeria when the ‘returns will not be as high as other projects in the portfolio’, Chairman and CEO, John Watson indicated that both gas projects in Nigeria are ‘very good projects’ which are oil price linked, while the EGTL project in Nigeria produces liquids that are priced at world product levels.

By March 2018, Chevron reported that activities carried out by NNPC and Chevron have reduced routine gas flaring by more than 90 percent in the Niger Delta since 2008. There is no mention of reduction of routine flaring in offshore assets.

[25] Mar. 09. 2010 / 2:00PM, CVX - Chevron Corporation’s 2010 Security Analyst Meeting
[26] Chevron, Annual report to the US SEC, Form 10-K (NYSE:CVX), 9 March 2004; https://stocklight.com/stocks/us/manufacturing/nyse-cvx/chevron/annual-reports/nyse-cvx-2004-10K-04656677.pdf

In 2006, Exxon Mobil reported investing USD 3 Billion "*to effectively eliminate routine gas flaring in our Nigerian operations by 2008* ".[27] In its Financial review to the SEC, it reported that two investments, the East Area Additional Recovery project and the East Area Natural Gas Liquids (NGL) II project, were being made to reduce routine flaring in Nigeria:

"*The East Area Additional Oil Recovery project ($2.3 billion, gross), inaugurated in 2006 to raise oil output from six Nigeria joint-venture offshore fields by gathering, compressing, and reinjecting into the oil reservoir gas that would otherwise be flared away. The project is expected to provide incremental recovery of approximately 560 million oil-equivalent barrels (gross) and a peak production increase of 120 thousand barrels of oil per day (gross).*"[28]

Notwithstanding these investments intended to eliminate Exxon's routine flaring in Nigeria by 2008, flaring continues today. The risk was highlighted in 2022, during discussions about Seplat's bid to acquire ExxonMobil's assets. Wood Mackenzie commented: "*ExxonMobil refused to be drawn into the high-risk domestic gas market and had no exposure to NLNG. As a result, the acreage has the highest concentration of gas flaring in the country. Seplat, a listed company, will need to tackle this immediately*."[29]

Usan is ranked as the third largest super-emitter in Nigeria after Yoho. At the commissioning of Usan in February 2012, Yves-Louis Darricarrère, President Exploration-Production at Total, stated:

"*I'm particularly proud to announce start-up of this major project together with the concession holder NNPC. This project demonstrates the ability of Total, a key operator of large-scale deep offshore developments in the Gulf of Guinea, to lead ambitious projects… Total as operator has introduced a number of technological innovations, among which is a solution that drastically reduces gas flaring and thus minimizes the project's environmental impact.*" [30]

No further information was provided on how this would be achieved.

In 2007, it was reported that NNPC, Total, ConocoPhillips and ENI were looking to build a new LNG plant on Brass Island. However, the two-train plant to be operated by ConocoPhillips was mothballed before construction began. Estimated costs in 2007 were expected to be $15 billion. In 2015, ENI confirmed that this LNG plant, to be built near the existing Brass Oil Terminal operated by ENI, would be supplied with 48 million m^3/d of natural gas. About 40% would be suppled from ENI operated blocks in onshore swamp and land areas, and the remainder was to be supplied by TotalEnergies. There is no mention of using offshore associated gas.

[27] ExxonMobil Corporation, "2006 Financial & Operating Review"; https://www.sec.gov/Archives/edgar/data/34088/000095013407006488/d44325exv99.htm
[28] See footnote 27
[29] NNPC cancels ExxonMobil's $1.6bn assets' sale to Seplat March 4, 2022 https://dailytrust.com/nnpc-cancels-exxonmobils-1-6bn-assets-sale-to-seplat/.
[30] Oil and Gas World, Usan FPSO, Nigeria https://oilandgas.world/viewtopic.php?t=959.

As mentioned, the Bonga asset performance evaluation report, Shell highlighted at the start of Bonga project development in May 2000, "*Shell prides itself in being the first oil company to have addressed the problem of gas flaring in a major way.*" [31] Yet, as Shell subsequently noted in its 2021 Global Sustainability report, "*Flaring at SNEPCo-operated facilities (i.e. offshore assets) increased by 160% in 2021 compared with 2020*". [32]

The Nigeria LNG plant was considered an important component of Shell's gas flaring strategy. Nigeria LNG has four shareholders: NNPC, Shell, Total and ENI. The first two Trains cost US$3.6 billion, financed by NLNG's shareholders followed by Train 3 with a cost of US$1.8 billion' [33] These increased Nigeria LNG's overall production capacity to over 17 mtpa. However, as discussed in the Bonga case study, Nigeria LNG is not operating at full capacity.

In summary, the Government of Nigeria and the international oil companies invested in developing gas monetization solutions and related infrastructure, in the decades before and after the commissioning of offshore super-emitter assets evaluated. Of these, only Bonga FPSO has facilities to transfer and utilize its produced gas onshore. Development commitments by the international offshore operators of these five assets (Chevron, Exxon, Shell, ENI, Total) to not routinely flare were not adhered to[34]. Detailed evaluations of flaring performance, conducted for each of these assets, have been extensively reported in the individual asset reports. These evaluations highlight that high flaring performance for these assets was tolerated, even though this would not have been accepted in other regulatory regimes, such as the EU, UK, or offshore US. In these cases, the international companies did not demonstrate that they could conduct production operations in a manner consistent with international standards.

Oil and gas regulations need to be implemented that make it mandatory to execute and maintain development or conservation solutions for produced associated gas (see Section 5.4). Best practices from other regulatory regimes, such as Norway could be adopted to ensure policies and regulations effectively ban the practice of routine flaring to produce oil.

5.4 Solution 4. Regulation and Fiscal measures – smart incentives for methane

Regulation is the preferred instrument of the IMF and the World Bank GGFR to 'universally discourage' gas flaring and venting. The IMF considers that carbon taxation is the most effective instrument to achieve the Paris targets on the basis that taxing emissions provides across-the-board incentives for energy efficiency and transition to cleaner fuels.

Nigeria's first Nationally Determined Contribution (NDC) submitted to the UNFCC in 2015 included gas flaring reduction as a mitigation measure, and its updated NDC in July 2021 for the first time integrates a commitment to reduce air pollution. The World Bank's Global Gas

[31] Offshore, "Shell's Bonga, EA development, deepwater renew interest off Nigeria", 1 May 2000; https://www.offshore-mag.com/home/article/16763405/shells-bonga-ea-development-deepwater-renew-interest-off-nigeria
[32] Shell Sustainability Report 2021 https://reports.shell.com/sustainability-report/2021/
[33] Australian and Nigerian LNG Projects: Insights for Resolving Challenges Facing New LNG Projects http://zantworldpress.com/wp-content/uploads/2015/05/217-Lynda-Andeobu.pdf
[34] Routine flaring and venting is prohibited in Nigeria https://flaringventingregulations.worldbank.org/executive-summary.

Flaring Reduction initiative (GGFR) is highlighting again the importance of regulation. In a useful recent review[35], the GGFR finds that 21 out of 28 jurisdictions ban routine flaring and venting while 54 oil producers have committed to ending routine flaring. Yet, the World Bank also finds that flaring emissions have not declined over ten years and in fact, increased in 2021.

There appears to be inconsistent long term follow up by Regulators to ensure that producing assets maintain compliant with conditions granted at the time of development approval.

An example of this is the need to maintain gas reinjection performance (see Box B). All five super-emitting offshore assets evaluated were designed to be a 'zero routine flaring' facilities in accordance with environmental policy, but this did not materialize. For four of these assets, all produced gas is supposed to be reinjected into the producing reservoir for conservation. Detailed analysis of these assets show that flaring is mainly the result of lack of gas re-injection capacity. In one case (Abo), installed gas production capacity was more than double the gas compression capacity which resulted in the FPSO often flaring close to 60% of produced gas. In the case of Agbami, parts of the gas compression equipment appear to be consistently out of commission. However, Agbami production was not restrained to limit flaring, other than to mitigate the impact of wind direction on flare that set off smoke / thermal alarms. When Agbami's flare tip needed to be replaced in 2016, it was observed that the lifting equipment on the flare tip platform, that was originally installed for flare-tip exchange, was so severely melted that it could no longer be used (see Agbami flare performance evaluation report).

More generally, penalties should be established at a sufficiently high level to make the alternative of investing in flaring and venting reduction more attractive than paying the penalty. This was also confirmed by recent work cited in the Phase I report by the Climate and Clean Air Coalition. Its work in Nigeria on pollutants such as methane found that the penalties for oil and gas companies which did not meet regulations were '*not enough of an incentive to force companies to comply*'.[36]

In 2018, the Government introduced the Flare Gas (Prevention of Waste and Pollution) Regulation which increased flare payments to USD 2.0 per one thousand standard cubic feet (28.317 standard cubic metres) of gas. In 2019, flare gas payments levied on companies increased substantially to a total of USD 307.5 million. It reduced somewhat to USD 257 million in 2020. Both however are significantly above the 2018 level, when NEITI reported that total penalties to be paid by all companies are USD 15.4 million.

[35] The World Bank, "Global Flaring and Venting Regulations", 5 May 2022; https://www.worldbank.org/en/topic/extractiveindustries/publication/global-flaring-and-venting-regulations
[36] CCAC Nigeria Supporting National Action and Planning https://www.ccacoalition.org/sites/default/files/resources/CCAC-SNAP-Factsheet-Nigeria.pdf

BOX B: Limitations in the application of gas reinjection as a standard methodology to avoid natural gas flaring and venting

The benefits of gas reinjection into oil reservoirs are multiple:

- Gas reinjection as voidage replacement in oil reservoirs provides reservoir pressure maintenance. The arrest of reservoir pressure decline is needed to maintain well flow rates and to overcome the back pressure caused by the weight of the fluids in producing wellbores.
- Gas reinjection can provide an improved macroscopic sweep of the reservoir, whereby oil is swept towards the producing wells and a higher oil recovery factor is obtained.
- Recycled natural gas is partially absorbed by the oil in the reservoir, improving its fluid characteristics (e.g., lower viscosity) to flow in the reservoirs towards the producing wells, leaving less residual oil trapped, i.e. an improvement of microscopic reservoir sweep.
- Gas reinjection can counterbalance aquifer ingress into the oil reservoir, particularly when this would lead to lower oil recovery and well-lift problems.
- Gas reinjection can contribute to a well offtake strategy, whereby excess gas is produced above the reservoir gas-oil ratio, thereby providing additional lift in the wellbore, avoiding the cost for deploying artificial lift to keep the oil wells flowing.

Consequently, gas reinjection not only can provide a mechanism for gas disposal, it can also result in higher oil recovery efficiency. However, not all oil reservoirs are suitable for gas reinjection, and in some situations a short circuit can occur between gas-injection wells and oil-producing wells, impairing oil recovery. In other oil reservoirs, a strong aquifer may counteract the beneficial impact of gas reinjection and cause lower oil recovery efficiency. In these cases, a more prudent approach than flaring or venting of the associated gas is to dispose the produced gas into a designated disposal reservoir that has been assessed and confirmed to be able to hold the gas volumes without leaking or spilling over into other reservoir structures or potable aquifers. Significant technical understanding exists on how to select and manage gas disposal reservoirs. This same approach is also a key methodology for carbon capture and storage. Produced gas can also be reinjected into commercial gas storage reservoirs, often depleted gas reservoirs, to manage seasonal swings in demand and to conserve gas for operational and strategic reasons. Furthermore, there are additional opportunities for gas utilization within upstream oil field operations, such as gas lift, engine fuel, and local power generation.

Extract from:
Romsom, E., and K. McPhail (2021). 'Capturing Economic and Social Value from Hydrocarbon Gas Flaring and Venting: Evaluation of the Issues'. WIDER Working Paper 2021/5. Helsinki: UNU-WIDER.
https://doi.org/10.35188/UNU-WIDER/2021/939-6

Starting in 2019, NEITI introduced project level reporting for the first time, covering 89 oil and gas companies. The 2019 audit report for the oil and gas sector shows that these five super-emitters combined incurred gas flare payments of USD 138.8 million, 45% of total payments. In 2020, their flare payments totalled USD 81.3 million, 32% of total payments that year. Individual asset payments for these five assets are set out in Table 4 below.

Flare penalties and flare taxes are positive measures to reduce flaring and to support the economic use of produced gas. Although it is difficult to assess the economic value of associated gas when its process infrastructure is not (yet) connected to the market, the two examples below demonstrate the importance of assigning such a value. Otherwise, the country's gas resources are potentially wasted as having little to no value.

Table 4: Annual oil production, annual flare rates and NEITI gas flare payments

FPSO	Oil production (million bbls p.a)		Flare rate (million m3 p. a.)		Gas flare payments (million USD)		Global flare ranking	
	2019	2020	2019	2020	2019	2020	2019	2020
Abo OML 125	19	16	99	95	1.8	7.3*	217	236
Agbami OML 128	178	143	292	219	61.3	24.4	74	100
Bonga OML 118	164	118	29	73	2.3	9.1	1,099	436
Usan OML 138	63	37	131	95	22.0	10.9	168	231
Yoho OML 104**	35	25	110	110	51.4	29.6	189	201

***Notes**: *In 2020, the gas flare payments included Abo OML 125 and OML 134;* ** includes OML 67, 68, 70.

The decision to redevelop Yoho from a depleted oil field into a gas field is the first example. As the Yoho case study shows (see Yoho asset flaring report), the Nigeria government has awarded a license to install a floating liquefaction (FLNG) unit at the Yoho field. This 1.2 mtpa FLNG facility will supersede gas reinjection, which is to be discontinued. The FLNG facility, Nigeria's first, will be able to process 5 million m^3 per day (152 million m^3 per month). The facility will also produce LPG and condensate. The development is financed by African Export-Import Bank (Afreximbank) for USD 2 billion with a further tranche of USD 3 billion available for the second phase of the project.[37]

That Yoho has been able to obtain USD 5 billion in financing to redevelop Yoho into a gas field implies that the value of the gas to be recovered and currently wasted has substantial economic value. The Yoho case study further shows that the volume of gas already flared at Yoho could have supplied the planned FLNG for 1.4 years. Figure 10 in Section 4 demonstrates that assigning an economic value for associated gas (i.e. a gas 'price' in USD / Mscf) can assist in determining the optimum economic point at which the field's value pivots in favour of a gas development over continuing the oil development. It is important to do this economic analysis on the basis of the volume of the oil and gas resources yet to be recovered instead of comparing the value of current oil production rates with the value of current flare rates. Late life oil production at high water and gas flaring can significantly compromise the future recovery of gas remaining in the reservoir.

The second example is Bonga FPSO, which has its gas processing facilities connected to the NLNG plant. Therefore any Bonga gas flared could have been monetised as LNG exports, for which there is high global demand. By the end of 2022, Bonga had flared a total of 1.4 billion m^3 of gas during its production life. This could have produced 855,000 tonnes of LNG, worth USD 420 million at Q4 2021 gas prices. In 2021 alone, Bonga is estimated to have flared 125 million m^3 of gas, worth USD 37 million as LNG. The gas flare payment for Bonga for 2020, the latest NEITI data available, is USD 9 million.

These examples and findings are consistent with the value of gas flaring wasted onshore Nigeria, as described in the Phase1 Report (see Footnote 6). The amount flared from 62 flares onshore flares, including four super-emitters has an estimated LNG gas sales value of USD 730 million per year, based on Q4 2021 LNG prices. In 2020, 4 super-emitters in the East Warri

[37] Enerdata, "Afreximbank signs a US$5bn deal for a floating LNG plant in Nigeria", 10 December 2021; https://www.enerdata.net/publications/daily-energy-news/afreximbank-signs-us5bn-deal-floating-lng-plant-nigeria.html.

region flared more than 65 MMscf/d gas with a value of more than USD 200 million per year at the same price.

The results of this flare performance evaluation show that the socio-economic benefits to Nigeria are significantly higher from monetising associated gas than the value from gas flare payments levied. To this matter of the lack of incentives for oil and gas operators, an additional issue was raised in the 2017 NEITI Audit, that not all penalties are paid. There are also reports that companies challenge the government's measurement of the quantity of emissions flared.

One solution is to apply the IMF's innovative proposal to tackle methane emissions in contexts where reporting still need further improvement or where regulatory measures are not enforced. In the absence of metering, taxes can be levied based on assumed default methane leakage rates. The benefit for Regulators is that they do not have to prove how much methane is emitted. This also provides incentives for operators as these penalties improve the commercial returns for reducing or repurposing the emissions. The repurposing of waste gas for local use may now become commercially attractive if penalties for (deemed) methane emissions are set at the right level.

A practical way to implement this is through a fee on oil production. Monthly production data for offshore producers are published by the Nigerian government and are not disputed. Using satellite data enables regulators to track flare intensity. All oil and gas producers would automatically pay the fee based on annual production. Those producers whose emissions are below a certain threshold of flare intensity would be able to apply for a rebate, which would be supported by actual measurements which have been validated.

Although regulations typically focus on limiting emission volumes, flare quality is even more important. The social cost of flaring increases immensely when the quality of the flaring process does not meet its 98 per cent destruction efficiency target. The contribution of CO2 to the SCAR from flaring is less than 10 per cent, as the greatest flare SCAR contributions are from methane, NOX, SOX, and BC as set out in Section 5.1. The IMF's proposal would also address the issue of flare quality, which is seldom measured.

Prior to COP27, the IMF integrated its proposals on methane penalties into its Staff Climate guidance on How to Cut Methane Emissions. It also noted that for the extractives sector, methane taxes are most technically feasible where upstream fiscal regimes are already established and that satellite technologies can facilitate measurement.

In summary, just as there have been advances in satellite technologies that aid regulators to measure flare volume and quality, so developments in regulations have advanced which result in regulators not having to prove how much methane is emitted. This can help Regulators in their monitoring to ensure that producing assets maintain compliance with conditions granted at the time of development approval. Where there are no independent measurement of emissions, the IMF recommends taxes are levied based on assumed default methane leakage rates. This creates incentives for operators to reduce routine gas flaring and venting operations as these erode their commercial returns.

The Global Methane Pledge has opened the door for public policies to be applied to level the playing field between companies, regulators, and policymakers. The 2021 Global Methane Assessment found that a methane tax is effective in reducing emissions from the energy sector and leads to an immediate drop in the implementation year. Few countries have implemented a methane tax to date.

This indicates that **regulatory** measures for flaring and venting require complementary actions in the areas of **measurement**; **accountability** and **transparency**; and **gas monetization**; as proposed by our 'Diamond' model.

6. Lessons Learned and Conclusions

6.1 Lessons Learned

This evaluation covers five offshore producing assets in Nigeria, including four deep-water FPSOs, and one shallow water facility, all of which are super-emitters during the period 2017-2021. The flaring and oil production characteristics of these five installations have been compared and metrics identified which can be used by regulators to benchmark the emission performance of assets.

Flaring should be characterized based on flare rate continuity, intensity, and variability. When upper limits of flare standards are exceeded, oil production must be reduced to keep flaring rates within limits. A clear definition of routine flaring is needed that reflects the policy: "operators shall not flare to produce". The distinction between routine flaring and non-routine flaring should not be based on whether flaring is a planned activity or not. Instead, flaring to continue production or maintain production is to be considered routine flaring. Flaring to safely halt production in case of system trips or equipment failures is non-routine flaring. Therefore, flaring due to continued production operations after a flash gas compressor (or other equipment) failure is to be characterized as routine flaring.

Natural gas flaring appears to be related to two distinct causes:

1) flaring caused by operational issues such as process trips and equipment failures
2) flaring due to excess gas production when oil wells exceed stable reservoir rates

Approvals for field development plans should specify maximum flaring limits. When the oil development plan is based on gas re-injection for conservation of the gas resource and/or for maintaining reservoir energy, asset operations need to comply with this requirement. Operators need to demonstrate to regulators that they meet the conditions of operations. In case of non-compliance, operators should commit to an improvement program to raise performance to a compliant level.

'Loss of oil' terminology in NNPC monthly reports may promote detrimental oil production policies: oil deferred is not lost and in case of production curtailment measures, oil deferment may prevent loss of ultimate recovery.

Our asset evaluations demonstrate the benefits if operators implement production policies that limit oil offtake to safeguard the environment (flaring) and technical integrity. Low flaring is a win-win, indicative of operational control that is shown to benefit oil production, as well as to lower emissions. This is a useful indicator for regulators and helps to deliver NDC commitments.

The key lessons learned from the detailed asset evaluations (documented in the individual flare evaluation reports) are summarized and categorized in Appendix B below.

6.2 Conclusions

There are large opportunities to generate significant tax income, improve health outcomes, and tackle climate change while continuing to extract and use natural gas – still a crucial energy resource for Nigeria. In 2021, oil accounts for over 80 percent of Nigeria's exports, half of government revenues, and a third of banking sector credit.[38] In 2022, the IMF found that oil production '*has suffered from security and technical challenges since the pandemic*'. It also noted that, '*the authorities' more optimistic growth outlook in 2023 and in the medium term is driven by a more positive assessment of oil production prospects'.* [39] In 2016, one third of Nigeria's oil production was delivered by five super-emitter assets. This declined to 20% in 2022, partly because these offshore assets have become more mature. However, the detailed performance assessments for these assets have also highlighted that high flaring is often positively correlated with high oil decline rates.

In 2022, Nigeria's Upstream Petroleum Regulatory Commission started a probe into Nigeria's oil production underperformance to determine conformity with the technical provisions and production terms. "*The commission will do everything within its authority to challenge the narrative and halt further degeneration by ensuring transparency in hydrocarbon accounting."*[40] This would include gas, production and utilization, and thus gas flaring.

A key priority is to improve the operational performance and production efficiency of global super-emitters. Among Nigeria's 181 flares, there are 18 global super-emitters and half of these are located offshore. The five assets evaluated together flared 11 percent of all Nigeria's flared gas (i.e. 0.6 Bcm out of 5.3 Bcm) in 2022. They are owned and operated by international oil companies which also operate offshore facilities in jurisdictions such as Norway and the

[38] Nigeria: 2021 Article IV Consultation-Press Release; Staff Report; Staff Statement, and Statement by the Executive Director for Nigeria; https://www.imf.org/en/Publications/CR/Issues/2022/02/09/Nigeria-2021-Article-IV-Consultation-Press-Release-Staff-Report-Staff-Statement-and-512944.

[39] Nigeria Article IV Consultation 2022 https://www.imf.org/en/Publications/CR/Issues/2023/02/16/Nigeria-2022-Article-IV-Consultation-Press-Release-Staff-Report-and-Statement-by-the-529842

[40] ThisDay, "NUPRC Begins Probe into Nigeria's Oil Production Underperformance, Says Issues Deeper than Oil Theft", October 2022; https://www.thisdaylive.com/index.php/2022/09/28/nuprc-begins-probe-into-nigerias-oil-production-underperformance-says-issues-deeper-than-oil-theft/

US Outer Continental Shelf, where flaring is tightly regulated. The companies pledged to bring world class solutions for '*a new era of the Nigeria oil industry*'. [41]

Measuring individual flare performance using satellite data shows large variations in operational performance between the five super-emitters, due to different causes of flaring. All assets flare continuously (i.e. 'routine' flaring) to produce oil, with only a small fraction of gas flared as a safety measure (7% to 24% in 2022). When oil production rates are higher than what the reservoirs can deliver, this increases natural gas flare rates significantly.

The good news is that the assumption that flaring is necessary to increase oil production and meet energy demand does not hold in Nigeria. Flare performance assessment demonstrates the benefits if operators implement production policies to limit oil production and to safeguard the environment (flaring) and technical integrity. Low flaring is a win-win: indicative of operational control that benefits both oil production and reduced emissions.

The potential sales value of flare gas is significantly higher than the penalties levied under Nigeria's regulatory framework. Bonga exports its associated gas to the NLNG plant and flared gas worth USD 37 million as LNG in 2021. Yoho is converting its oil fields to gas production, and USD 5 billion was raised in loans for an FLNG facility, to process the associated gas.

Reducing atmospheric emissions is not solely a global warming issue. Methane also affects air quality and has a disproportionately large impact on health. **Satellite measurements also enable flare quality** to be established. This is particularly important since poor quality flaring is a result of incomplete flare gas combustion which results in methane and other chemical emissions, such as NO_X, SO_X and Black Carbon. In Nigeria, the overall trend in operational flare quality is established by assessing the frequency of poor flaring events. These events appear to have distinct patterns. As part of the study, a recommended metric was derived to compare flaring performance between assets which reflect their impact on climate and air quality.

The IPCC Synthesis Report published in March 2023, shows that limiting global climate change to below 1.5°C is not at all on track. In a statement alongside the release of the report, the UN Secretary General said: '*This report is a clarion call to massively fast track climate efforts by every country and by every sector and on every timeframe*.'[42] The report highlights the critical imperative to reduce methane emissions from the energy sector. With solutions immediately available, this can buy time for other technologies to be developed and deployed. The IEA finds that methane emissions from the energy sector increased to a near record in 2022, after rebounding by almost 5% in 2021.

The IPCC reports highlight risks to investors, under increasing pressure to demonstrate that they are not investing in companies that are actively contributing to global emissions. Investors, often with little or no information on the scale and scope of this valuable wasted

[41] "Usan, a new era for Nigeria's oil industry", 16 April 2012; https://www.yumpu.com/en/document/read/28867412/usan-a-new-era-for-nigerias-oil-industry-total-nigeria.
[42] British Medical Journal, "Climate change: Window to act is closing rapidly, warn scientists", BMJ 2023;380:p674, 21 March 2023; https://doi.org/10.1136/bmj.p674

energy resource, are calling on **companies to disclose emissions,** using standardized frameworks. Central Banks are focusing on the impact of material climate risks on the financial sector, including from 'stranded assets'. These Central Banks are adopting guidelines for commercial banks and financial institutions to report and disclose climate-related risks in line with the Task Force on Climate-related Financial Disclosures (TCFD).

Natural gas is the second largest global energy source and 7.5 percent of all gas produced is wasted each year by natural gas flaring and venting, with a gas sales value of USD 100 billion at Q4 2021 prices. Reducing these emissions at source would provide producing countries with much needed finance from their own efforts.

Global climate finance flows almost doubled between 2011 and 2020. However, climate finance for methane is less than 2 percent of all global climate financial flows. Technical support to promote the benefits and help develop the necessary regulatory structures is also correspondingly small. Natural gas repurposed from waste to resource has significant economic and commercial value. **Regulatory and fiscal measures can create incentives for gas monetization.**

Nigeria, the 6th largest global LNG exporter, can seize opportunities from super-emitters to support Nigeria's "Decade of Gas Initiative".[43] Tackling gas wasted through flaring and venting can integrate decarbonization of existing assets into the Just Energy Transition. This requires minimizing emissions as much as possible and preventing local pollution impacts. Oil and gas buyers are now rewarding producers who achieve this through price premia and larger market share. Investors will increasingly direct capital towards companies that work with governments to achieve this. This in turn will deliver additional revenues for government.

This 7.5 percent of global natural gas flared and vented also causes 54 percent of the total social cost of global natural gas, produced and used. In sum, by reducing methane emissions and wastage, Nigeria can get direct and immediate local benefits: gas for local energy access or financial proceeds from gas export, while the carbon intensity of its energy sector reduces, which helps to diminish EU cross-border taxes for crude oil produced. Box C provides practical considerations for Regulators to capture this economic and social value.

To successfully address natural gas flaring and venting the four elements of the Diamond Model (Figure 14) need to work in concert:

- **Independent measurement by satellites** of the volume of global flare and vent emissions from point sources on a daily basis. Satellite data enable Regulators to verify company reports of volumes of gas flared and investigate asset performance further in case of deviations. Even greater benefit can be achieved if regulators verify flare quality when evaluating operational performance to assess methane, NO_X, SO_X and

[43] Gas Exporting Countries Forum, "GEFC member Nigeria heralds 'Decade of Gas' to transform its future", 30 March 2012; https://www.gecf.org/events/gecf-member-nigeria-heralds-'decade-of-gas'-to-transform-its-future.

black carbon from each emission source. Detailed, comprehensive, continuous and consistent data from individual emission sources significantly improve transparency.

- **Transparency and disclosure**. High-resolution spatial data from satellites identify the owners of individual emission sources. Disclosure of all emissions can validate compliance with regulatory frameworks, create the basis for fiscal models that apply taxes on emissions. Transparent company reporting inform regulators as to whether the taxes or fines are charged at levels that reflect the economic value of the gas.

- **Gas monetization**. Carbon (and other atmospheric releases) pricing creates incentives for operators to reduce gas flaring and venting volumes. These improve the commercial returns for gas monetization. In turn, this creates new livelihood opportunities as well as added value from increased gas as e.g. transportation fuel and export of high-value products (e.g. LNG). Repurposing waste gas into economic use improves companies' social licence to operate given the (disproportionate) benefits to air quality, health, and climate.

- **Regulation and fiscal measures.** Any producing country able to enact appropriate regulatory and fiscal arrangements can realize the mentioned benefits while also generating much needed additional fiscal revenues. Regulators do not need to prove how much methane is emitted. Satellite monitoring of oil and gas facilities could be made a condition of field development, with information to be submitted to the Regulator. The IMF framework based on deemed emissions and rebates puts the onus of measurement and verification at the operators instead of the Regulators. This is because operators have the best information on the operational performance of their assets, but may need to be guided (through the IMF framework) to provide objective and transparent reporting. A Top 200 super-emitters list of these high emission sources, which combines both flaring and methane emissions, would support regulators and the IMF by identifying exact locations and volumes of emissions flared to determine the total gas sales value of super emitters. The newly created IMF Resilience and Sustainability Fund could provide funds to finance implementation of the technical work needed to realise the benefits from gas flare reduction.

When these four elements of our action plan are combined, the Diamond model helps to reconcile the dilemma between development needs and reduced emissions:

- Nigeria captures economic value (less wasted gas and additional Government revenues) and social value with contribution to UN Sustainable Development Goals.
- Large health, climate and agriculture benefits if super-emitter volumes and impact are significantly reduced.

BOX C Practical considerations for Regulators to capture economic and social value

A useful recent review by the World Bank Global Gas Flaring Initiative [44] also includes many of these suggestions set out below:

1. Satellite data enable Regulators to identify super-emitter flares and to verify asset performance for remote assets that otherwise would be very difficult to obtain independently.
2. A clear definition of routine flaring is needed that reflects the principle: 'operators shall not flare to produce'. This should be defined based on flare rate continuity, variability and intensity.
3. Approvals for oil field development plans should specify maximum flaring limits to optimise oil production and recovery of reserves. When the oil development plan is based on gas re-injection, asset operations need to comply with this requirement.
4. Regulations need to be implemented that make it mandatory to have a development or conservation solution for produced associated gas.
5. Transparent reporting by operators to demonstrate they meet conditions of the oil development plan. Emissions reported based on absolute metrics, e.g. the amount of gas flared. In case of non-compliance, operators commit to an improvement program to raise performance to a compliant level.
6. Satellite technologies help regulators assess the volume of gas flared, regardless of transfer of ownership or operatorship.
7. There appears inconsistent long-term follow up by Nigerian regulators to ensure that producing assets maintain compliance with conditions granted at time of development approval.
8. Recommended metrics for regulators to determine operational performance and determine when a depleted oil field should be changed to a gas field.
9. Satellite data can help regulators detect and attribute oil leaks due to offshore operations.
10. Regulators can work with other government agencies to:
    a. Enable third-party gas sales and third-part access to gas infrastructure to support action to get associated gas to market.
    b. Facilitate a tax on 'deemed' gas flared and vented to change the commercial baseline for investment. Using gas sales value would yield higher revenues than penalties levied under Nigeria's regulatory framework.

6.3 Comments from ENI Nigeria, TotalEnergies Nigeria, Shell Nigeria Exploration and Production Company, and follow up responses

In June 2023, EnergyCC and Oxford Policy Management (OPM) sent copies of the Nigeria super-emitters onshore report and offshore report (this report) in draft to the operators of four onshore super-emitters in the Niger Delta, the operators of the five offshore super-emitters, and to Nigeria LNG, with the request to review the draft and correct any factual errors. The request was sent to the company representatives provided by NOSDRA, the Nigeria Regulator. It asked for comments in a four-week period and indicated that feedback received would be incorporated into the draft report before publication.

[44] GGFR Global Flaring and Venting Regulations: 28 Case Studies from Around the World, 2022; https://thedocs.worldbank.org/en/doc/fd5b55e045a373821f2e67d81e2c53b1-0400072022/related/Global-Flaring-and-Venting-Regulations-28-Case-Studies-from-Around-the-World.pdf.

Comments were received from ENI Nigeria. In July 2023, a second follow up request was sent to the remaining Operators: Chevron Nigeria, Exxon Mobil Nigeria, Shell Nigeria, and TotalEnergies with another four-week period for comment. This time, comments were received from TotalEnergies (October 2023) and from Shell (November 2023). No comments have been received since from the remaining operators. See the section below for details on individual company comments.

The comments received show that all three companies are now taking steps to reduce flaring for operated assets but not yet for third-party operated assets. Two companies, ENI and Shell set out action plans currently underway to improve their flaring and methane emissions framework. **ENI** has a four point plan, to be completed in 2023, that includes:

1. Shutdown maintenance activities to improve HSE and operational performance.
2. gas Flare meters installed to measure actual flaring;
3. all methane emissions to be validated by an accredited 3rd party;
4. a third compressor installed for use during maintenance activities and reduce flaring.

ENI expects these actions will enable the company to define further solutions and strengthen and improve its current emissions framework.

In addition to flaring specific activities, **Shell** observes that operational efficiency contributes significantly to flare reduction. Bonga is part of Shell's strategy to reduce to reduce all Scope 1 and 2 absolute emissions by fifty percent by 2030 compared to 2016 levels, and achieve net zero emissions by 2050. This is being done by:

1. gas flare meters have been installed for Bonga to measure actual flaring;
2. flare efficiency is measured with maintenance undertaken as needed;
3. flare intensity is used as a key metric to manage flare performance as the field production declines
4. a pilot flare elimination project will be executed with the aim of Bonga becoming a zero flare facility.

TotalEnergies, engages with Shell (operator of Bonga) and Exxon (operator of Usan) as joint-venture partners, as TotalEnergies does not operate these assets[45]. The aim is to encourage these operators through workshops and technical meetings to undertake the following steps in the areas of flaring and venting; leaks and fugitives reduction and fuel gas reduction that TotalEnergies is implementing on its operated assets in Nigeria:

1. Egina FPSO designed and operated as a no flaring facility;
2. no routine flaring on operated sites from end-2023 onwards;
3. closed flare and vent recovery systems being gradually implemented on all sites;
4. methane leak detection programmes using Infrared cameras and drones;
5. quantify all leaks on all sites towards OGMP 2.0 gold standard;
6. zero flaring on new projects.

[45] Total (now TotalEnergies) transferred operatorship of Usan to Exxon in 2014.

These emissions reduction commitments, made by the companies who have responded to the request for comments on their offshore Nigeria flaring performance, are very welcome. The continued application of satellite data to monitor the implementation of flaring and venting reduction measures will provide regulators and other stakeholders (such as investors) with the means to validate these commitments. The engagements with the companies based on this work underline the importance of transparency, one of the four elements in the Diamond Model, the solutions framework for emissions reductions (see Section 5).

Individual company comments

ENI

Comments were received from ENI Nigeria Public Affairs Department, as follows:

> *With reference to your mail of June 22nd 2023….*
>
> *Before going through the main concepts, let me strongly highlight and confirm that Eni applies and respects the Country legislations always acting in transparency and cooperation with the Environmental Regulatory Agencies and Authorities as per Country's Governmental Laws.*
>
> *As a second aspect, I would frankly appreciate the transparency of your Report which gave us the possibility to have an additional check of our data and environmental strategies on which, as you know, we are fully focused.*
>
> *With regard to your Report, we would firstly highlight some inconsistencies (see below, the main points):*
>
> 1. *Flaring Measurement – some misalignment between our data and the ones provided;*
> 2. *Gas Production Capacity and Injection – Current FPSO design configuration is able to reinject 95% of associated gas;*
> 3. *Oil Spills – No subsea spills reported in the last 8 years. We are periodically carrying out subsea Campaigns which did not highlight any issue on this matter;*
>
> *In terms of proposed solutions to improve our Flaring/Methane Emissions, we are currently working on the following actions:*
>
> 1. *Firstly, it is really important to mention that Abo FPSO is currently under total shutdown, which has been planned and implemented to improve both, HSE and operational performance (even to the detriment of Production);*
> 2. *OGMP Campaign execution, through which all the methane emissions will be accounted by accredited 3rd party (within 2023);*
> 3. *Flare Metering installation within current year to have a precise account of flaring;*

4. *A third Compressor is being installed to have redundancy during maintenance activities and reduce flaring;*

Following the above actions, for which we will have a clear picture within end of the current year, we will be able to define further solutions and strengthen the current strategies to improve our emissions framework.

EnergyCC and OPM appreciate the acknowledgement of the Report and the efforts taken by ENI, to follow up and provide the comments above. The ongoing efforts by ENI as highlighted by the four actions are highly appreciated and are expected to make a very positive impact going forward.

Regarding the three inconsistencies highlighted by ENI, the authors of the Report addressed these by providing the following responses:

1) *Flaring Measurement – some misalignment between our data and the ones provided*:

In their response, ENI acknowledge to be installing flare metering this year (2023). Without such flare metering available to date, it is unclear how ENI would compare their flare rates with satellite measured flare rates. The satellite flare rate measurements are based on a standard and consistent methodology adopted by World Bank and other leading institutions such as IEA, NEITI, etc. Once ENI's flare metering for Abo FPSO is operational, it would be interesting to compare the metered data with satellite data. Self-reporting of flaring in the absence of calibrated metering and independent verification may lead to under-estimation in flare rates. This was highlighted by the Guardian NG in their March 2023 article: under-reporting of self-declared flare data, when compared with World Bank satellite data, worsened with increased penalties on gas flaring (https://guardian.ng/features/focus/gas-flaring-crafty-operators-tax-evasion-endanger-children-unborn-babies/).

2) *Gas Production Capacity and Injection – Current FPSO design configuration is able to reinject 95% of associated gas:*

The flare evaluations reports (including Abo FPSO) consistently highlight that even if assets are designed for zero flaring (i.e. able to re-inject the produced gas), in practice these assets are flaring at super-emitter rates. One key reason is that gas-reinjection facilities are costly to maintain and hence re-injection capacity has a tendency to reduce over time. With the Abo development, the key operational challenge appears to be in managing the subsea facilities. Multiple references to blocked flow lines and impaired gas injection wells are included in the Abo asset evaluation. Therefore, ENI's statement on 'current FPSO design configuration' is less relevant if the subsea facilities are not able to inject the gas processed by the FPSO topsides into the subsurface. Moreover, most developments under-estimate the contribution of free reservoir gas in late field life production phase. In addition, associated gas rates depend on oil production policy. The analysis has shown that aggressive production policies cause a significant increase in associated gas production (and a decline in oil reserves) that can exceed the volumes that can be re-injected and hence result in excess flaring.

3) *Oil Spills – No subsea spills reported in the last 8 years. We are periodically carrying out subsea Campaigns which did not highlight any issue on this matter;*

Although ENI's statement says that no subsea spills were reported, this does not imply that no such spills may have occurred. There are several publicised reports of Abo's blocked subsea flow-lines, wells and other subsea equipment, and repeated efforts were reported to unblock these. It is therefore possible that faulty subsea equipment and the subsea intervention operations may have resulted in subsea discharges. Some of the reports about the state of Abo's subsea infrastructure also highlight that problems were inadequately diagnosed and poorly resolved. The subsea oil leak referenced in the Report is based on a separate earlier study by Visio Terra during 2018 and 2019. Visio Terra is a reputable company founded in 2004, see https://www.visioterra.fr/web/spip.php.

TotalEnergies

Comments were received from Mr. Matthieu Bouyer, Managing Director and Country Chair, TotalEnergies Nigeria:

I would like first to apologise for our late reply. Here are some elements that could be of help on TotalEnergies activities in Nigeria.

On TotalEnergies' operated perimeter (which is not treated in your report), we are putting a lot of efforts to reduce our emissions through reduction of flaring, of methane emissions and of Fuel Gas related emissions…The result appears partly in the Appendix A of your report on the FPSOs EGINA/AKPO that are well ranked. Below a few examples of actions we take to reduce our carbon footprint:

Flaring and Venting

- *Egina FPSO designed and operated as no flaring facility.*
- *Zero flaring on new projects such as Ikike project*
- *Application of ALARP flaring policy on all sites as per company rule.*
- *No Routine Flaring shall be achieved in Nigerian TTE operated assets at end-2023*

- *Closed flare and vent recovery system planned being gradually implemented on all sites*

<u>Leaks/Fugitives reduction</u>

- *Passing valves detection campaigns through Leak Detection and Repair (LDAR) on all sites using IR cameras and intervention on identified valves especially during FFSD*
- *Methane detection via TTE proprietary drone measurement technology ("AUSEA" Airborne Ultralight Spectrometer For Environmental Applications) campaigns commenced in the affiliate in 2022. New campaign planned by end 2023*
- *QLDAR campaign planned in 11/ 2023 on all sites to quantify all leaks towards OGMP 2.0 gold standard – (Oil & Gas Methane Partnership 2.0)*
- *Future QLDAR/AUSEA campaign to be deployed by local vendor at least once a year*
- *Sites to maintain the regular LDAR campaign.*

<u>Fuel Gas reduction</u>

- *Gas turbines filters upgrade on All sites, except Egina designed with improved filters*
- *Solarization campaigns - OML58 (5 MW), Egina, Akpo, PHC bases/offices (< 1 MW)*
- *Optimization of operating points for rotating machinery post energy efficiency studies. Example on Egina with pressure reduction on Water Injection Pumps.*

*On our <u>non-operated assets</u> of Nigeria and in particular the **2 FPSOs you indicate in your report as super emitters (Bonga and Usan)** we are not operators but partners. As such, we leverage as much as possible our position to influence the operators and have had workshop(s) and technical meetings with them to encourage them to take similar steps as ourselves. For further information, I would encourage you to contact the operators directly.*

Do not hesitate to reach out if you need further information.

Best Regards,
Matthieu Bouyer

EnergyCC and OPM appreciate the acknowledgement of the Report and the efforts taken by TotalEnergies (Mr. Matthieu Bouyer), to follow up and provide the comments above. The implementation by TotalEnergies of the actions in the areas of flaring and venting; leaks and fugitives reduction and fuel gas reduction on its operated assets in Nigeria are expected to make a substantial impact in the further reductions of emissions. Equally welcome are the actions undertaken by TotalEnergies to exert influence in the assets that are operated by others and in which TotalEnergies holds participating interests. It is critically important that companies not only take accountability for emissions for their own operations but also for the emissions of other assets in which they have a participating interest. This accountability includes the reporting of emissions for such non-operated assets. The example of handover of operatorship for Usan asset from Total to Exxonmobil in 2014 exemplifies how emissions 'can disappear' due to inconsistent reporting by companies (see Box A). Another positive point is the flaring performance of TotalEnergies' operated asset Egina. As the world's largest FPSO, Egina is located 150km off the coast of Nigeria in Gulf of Guinea, at a challenging water depth of approximately 1,600m. [46] It that came on production in December 2018 and ranked 6,339th out of 10,000 global flares in 2021 (see Appendix A). This indicates that the flare performance of other offshore assets can be significantly be improved by adopting modern standards and that a large asset size (and high production levels) does not have to result in high flaring rates.

Shell

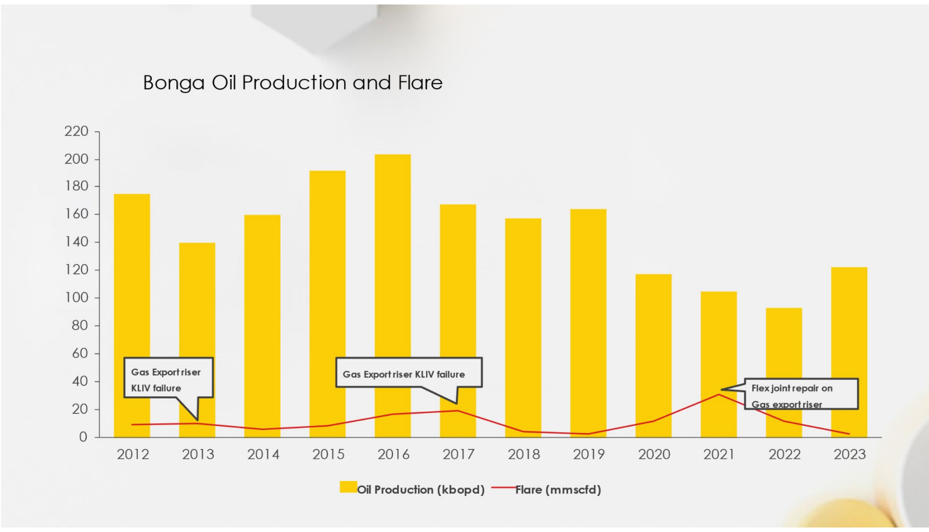
Comments received from Ms. Elohor Aiboni, Managing Director, Shell Nigeria Exploration and Production Company:

> *Find below our response to the report commissioned by Oxford Policy Management Ltd and prepared by EnergyCC.*
>
> *With respect to the report, we must make a few clarifications:*
>
> - *The design of Bonga comes with a base safety pilot flare.*
> - *Bonga has valid and approved gas (including flare) meters for measurement which is calibrated bi-annually. See below a historic plot of Bonga's gas oil production and flare and a table of the intensity from 2012 to date. As noted in the report, Flaring Intensity is measured based on gas flared and barrel of oil produced, as long as the pilot range remains, the intensity will definitely go up as the field declines (as can be clearly seen from the table below the plot). In order for the flare intensity to be low, further field development must be considered (reference 2014 when Bonga North West came on stream) or an upgrade of the entire flare system has to be done to achieve zero flare system (the upgrade done in 2021/22 on the low gas compressions system has led to a remarkable reduction in flaring as seen in 2023 flare/intensity figures).*
> - *SNEPCo sustainability report clearly talks about our governance and regulatory framework. The reference from the model that assumes that no regulatory or company governance exists is misleading.*

[46] Egina is the world largest FPSO (2022), is operated by TotalEnergies, and started production in December 2018, https://www.offshore-technology.com/projects/egina-field/?cf-view.

- *Combustion efficiency drives the quality of any flare system not the volume, every flare system has a program to inspect the vessels and flare system – that way you can ensure the efficiency of any system. Where there is need to carry out maintenance appropriate plans are made.*
- *Operational efficiency contributes significantly to flare reduction, and that has been Bonga's focus in tandem with Shell's energy transition and decarbonisation roadmap theme (50% reduction in absolute emissions by 2030 compared to 2016 levels, covering all Scope 1 and 2 emissions under Bonga's operational control with near-term emission reduction opportunities and achieve a net zero emission by 2050)*
  - *Bonga continues to drive operational efficiencies despite some asset integrity challenges that it has experienced (as seen in 2013 and 2017 when we had the KLIV failure and 2022 when we had a flex joint elastomer failure on the gas export riser). Current average daily flare volume is less than 1mmscfd and 2023 YTD (end Oct) performance is 2mmscfd which is circa 65% less than the 5.7mmscfd super-emitter threshold.*
  - *As part of our drive to achieve zero flare, a pilot flare elimination project will be executed as part of the Bonga life extension program and upon completion Bonga will become a zero-flare facility, eliminating the current safety pilot flare.*

SNEPCo is also signed up to the United Nations clean climate coalition and has implemented methane emission measurement and eliminating technologies as part of the oil and gas methane partnership.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 end Oct)

Production	175	139.5	159.6	191.9	203.4	167.7	157.8	164.1	117.5	105.1	92.9	124.3
Flare (MMSCFD)	9.04	9.71	6.03	8.63	16.44	19.56	3.76	2.89	11.63	31.01	11.9	2.0
Flare Intensity	0.00838	0.01131	0.00614	0.0073	0.01312	0.01893	0.00387	0.00286	0.01607	0.04792	0.02079	0.00261

Regards
Aiboni, Elohor

EnergyCC and OPM appreciate the acknowledgement of the Report and the efforts taken by Shell (Ms. Elohor Aiboni), to follow up and provide the comments above. The ongoing efforts by Shell as highlighted by the response are highly appreciated and are expected to make a very positive impact going forward.

Regarding the comments made by Shell, the authors of the Report addressed these by providing the following responses:

- The existence of calibrated flare meters on Bonga is very encouraging as these flare rate measurements provide the operator with direct feedback on flare performance. The availability of flare rate and flare quality information provides an opportunity for Nigeria's regulators and other stakeholders to monitor Bonga's flare emissions performance over time. The authors would welcome further data exchanges on (daily and monthly historic) flare rates, flare quality and methane emissions for Bonga as this allows the capability (and limitations) of satellite measured flare rates to be verified. Shell's comments do not mention if Bonga flare rate measurements and methane emissions are third party accredited, but if not, this would be a welcome next step in transparency.
- Despite efforts by the authors, the SNEPCo sustainability report was not found through a web search. The authors would welcome receiving a copy. The Shell Sustainability Report 2021 has been rereferred to in this Report as Reference 18 on Page 25. The authors also acknowledge the Shell Sustainability Report 2022 that mentions reduced flaring at SNEPCo Nigeria (together with other Nigeria related activities, including handover of OML 11 license to NPDC) as key reasons for Shell's lower methane emissions in 2022 compared to 2021. [47]
- The authors infer that the comment "*The reference from the model that assumes that no regulatory or company governance exists is misleading*." relates to the Diamond model introduced in Section 5 of the report. In Section 5.4 the improvements sought in the current regulatory framework are detailed. The three key improvements recommended are: 1) more consistent long term follow up by Regulators to ensure that producing assets maintain compliance with conditions granted at the time of

[47] The latest Shell Sustainability Report 2022 is located here https://reports.shell.com/sustainability-report/2022/.

development approval. All five super-emitting offshore assets evaluated were designed to be a ‘zero routine flaring’ facilities in accordance with environmental policy, but this did not materialize; 2) penalties should be established at a sufficiently high level to make the alternative of investing in flaring and venting reduction more attractive than paying the penalty; 3) In accordance with the 2017 NEITI Audit, ensure that all penalties are paid and to consider the IMF’s ‘deemed emissions and rebates framework’ for methane as a potential solution for oil and gas companies to take increased accountability of their emissions, instead of companies challenging the government’s measurement of the quantity of emissions flared.

Therefore, governance and regulatory frameworks do exist, but further steps must be taken to ensure that these are complied with as evidenced in the concluding sentence in Section 5.4. To avoid any misinterpretation, the authors have include the word ‘enhanced’ in ‘(4) enhanced regulation and fiscal measures‘ at the introduction of this topic at the beginning of Section 5.

- The reduction targets set by Shell for reduction and elimination of Bonga flaring are very welcome and verifiable by independent satellite monitoring.

Appendix A: Overview of FPSOs in Nigeria

FPSOs in Nigeria	Location	Oil Rates	Ranking
ABO FPSO ○ *Abo Oil Field*	5.708575 N / 4.48100 E	Y	206
Agbami FPSO ○ *Agbami Oil Field*	3.46262 N / 5.56051 E	Y	39
Akpo FPSO ○ *Akpo Oil Field*	3.142146 N / 6.82312 E	Y	670 (in 2021)
Armada Perdana FPSO ○ *Oyo Oil Field*	5.386644 N / 4.59000 E	Y	ceased
Armada Perkasa FPSO ○ *Okoro Setu Oil Field*	4.403874 N / 7.828436 E	Y	623 (in 2021)
Bonga FPSO ○ *Bonga Oil and Gas Field*	4.554563 N / 4.615810 E	Y	348
Egina FPSO ○ *Egina Oil Field*	3.001953 N / 6.716387 E	after 2019	6339 (in 2021)
Erha FPSO ○ *Erha Oil Field*	5.359015 N / 4.342074 E	Y	136
Falcon FPSO ○ *Yoho Oil Field*	4.017314 N / 7.492048 E	Y	119
Mystras FPSO ○ *Okono Oil Field* & *Okpoho Oil Field*	3.989437 N / 7.289822 E	Y	193
Sea Eagle FPSO ○ *EA Oil And Gas Field*	4.802638 N / 5.311551 E	Y	841 (in 2021)
Sendje Berge FPSO ○ *Okwori Oil Field*	3.854888 N / 6.980304 E	Y	2419 (in 2021)
Usan FPSO ○ *Usan Oil Field*	3.575664 N / 7.393632 E	Y	135

Selected asset, fall-back asset

Appendix B: Lessons Learned from asset flare performance evaluation

***Table 5**: Overview of lessons learned from the evaluation of the five offshore super-emitter assets*

Category	Asset	Description
Routine flaring definition	Agbami	The distinction between routine flaring and non-routine flaring should not be based on whether flaring a is planned activity or not. Instead, routine flaring should be defined based on flare rate continuity, variability and intensity. When upper limits of flare standards are exceeded, oil production must be reduced to keep flaring rates within limits.
Routine flaring definition	Usan, Abo, Bonga	A clear definition is of routine flaring is needed that reflects the policy: "operators shall not flare to produce".
Facilities design	Abo	Facilities need to be designed with gas processing capacities that are commensurate with a low or zero flaring policy. In case of Abo, installed gas production capacity is 114 MMscf/d, while topsides gas compression capacity is only 48.4 MMscf/d (42% of the gas production capacity). It is no surprise therefore that gas flaring for Abo often is close to 60% of produced gas.
Compliance with development plans and approvals	Agbami, Yoho	Approvals for field development plans should specify maximum flaring limits.
Compliance with development plans and approvals	Usan	Usan's high flaring performance, detailed in Total's SEC 2013 filing, exemplifies that it has not been performing in line with its development plans and approvals thereof.
Compliance with development plans and approvals	Agbami	When the oil development plan is based on gas re-injection for conservation of the gas resource and/or for maintaining reservoir energy, asset operations need to comply with this requirement.
Compliance with development plans and approvals	Usan	There appears inconsistent long-term follow up by Nigerian regulators to ensure that producing assets maintain compliant with conditions granted at time of development approval.
Compliance with development plans and approvals	Abo	Operators need to demonstrate to regulators that they meet the conditions of operations. In case of non-compliance, operators should commit to an improvement program to raise performance to a compliant level.
Operational control	Bonga	Shutdowns and repairs that are reactive to some process failure or equipment breakdown are often preceded by high flaring events. Other pre-planned and proactive shutdowns are not accompanied by excessive flaring.
Operational control	Bonga	Low flaring is indicative of operational control that benefits oil production, as well as lower emissions.

Category	Asset	Description
Ultimate Recovery	Agbami	Excess gas flaring may compromise oil production rates and ultimate recovery if gas reinjection is part of the field development.
Ultimate Recovery	Yoho	The interrelationship between unstable operational performance and reservoir performance aggravates flaring. However, setting strict flare limits improves both operational and reservoir performance
Ultimate Recovery	Bonga	High flaring events are a leading indicator of oil deferment in subsequent months.
Ultimate Recovery	Bonga	Flare rates and oil decline rates are positively correlated, i.e. high flaring generally coincides with lower average oil production than in the same period a year earlier. An exception is high flaring when newly developed oil is brought on stream.
Ultimate Recovery	Usan	Periods of high flaring are often correlated to higher oil decline, and lower flaring to lower oil decline. However, Usan's relationship between flare performance and oil decline is governed by an apparent limitation in gas injection. This implies that to produce more oil, flare rates also increase (positive correlation). However, when reservoir offtake is too high and too much gas is produced, wellhead pressures decline, causing unstable well performance and increased oil decline (negative correlation).
Ultimate Recovery	Usan	Periods with increased frequency of potential poor flaring events indicate degradation in emission performance. For Usan, periods of poor flaring coincide with increased flare variability and increased oil decline rates in excess of the 15%.
Flare Variability	Bonga	Analysis of flare variability can assist in distinguishing production periods with upsets that more systemic and longer lasting (i.e. due to equipment failures) from periods with shorter process trips with quick recovery.
Flare intensity	Agbami	Flare intensity is a leading indicator for oil decline rates. Hence, flare intensity is a useful diagnostic for oil and gas regulators to ensure ultimate recovery is not compromised by quality of operations.
Flare Intensity	Yoho	Flare intensity (volume of gas flared divided by volume of oil produced) is a useful metric to determine the efficiency in oil recovery as a function of gas wasted through flaring, and thereby can assist when late-life oil production should be halted.
Causes of flaring	Yoho	flaring caused by operational issues such as process trips and equipment failures.
Causes of flaring	Yoho	flaring due to excess gas production when oil wells exceed stable reservoir rates.
Late life assets	Abo	It is observed that when a high cost oil field (such as deep water offshore) reaches maturity, operational standards are at risk of being relaxed, to meet the objective of maintaining positive cashflow by producing more oil at lower cost.

Category	Asset	Description
Late life assets	Abo	The lowering of production operations standards in mature fields can become aggravated when companies have a deadline to stop routine gas flaring before an impending date. Instead of investing in improved gas injection, or other measures to reduce flaring, companies may embark on a short-term strategy to maximise short-term oil recovery before the deadline to stop routine flaring kicks in.
Late life assets	Yoho	Flaring due to exceeding reservoir delivery constraints occurs particularly in late field life and can be a major contributor to high flare intensity operations.
Late life assets	Agbami	Also for late life assets, strict gas conservation measures on operations should be imposed.
Late life assets	Yoho	Late life flaring is exacerbated by process trips due to unstable well performance.
Late life assets	Agbami	With fields that are now in late life (more than 85% of oil ultimate recovery produced), it is advisable to review whether a switch of from an oil development to a gas development provides more overall value.
Production Targets	Yoho	Instead of targeting annual oil production rates, late-life assets should operate strictly within a monthly flaring volume allowance. This conserves gas to maintain reservoir drive (oil ultimate recovery) and preserves it for future use. Restricting offtake within specified flaring limits will result in more stable operations and less process trips, assisting oil production due to a higher volumetric uptime.
Production targets	Yoho	'Loss of oil' terminology in NNPC monthly reports may promote detrimental oil production policies: oil deferred is not lost and in case of production curtailment measures, oil deferment may prevent loss of ultimate recovery.
Flare performance metrics and benchmarks	Yoho	The recommended metric to compare flare performance between assets is the cumulative volume of gas flared versus time period of gas flared ('flare volume versus time') instead of flare intensity.
Flare performance metrics and benchmarks	Usan	Although absolute flare rates and volumes are the prime focus for establishing socio-economic and financial impact from gas wastage, the use of relative measures such as flare intensity can be useful in comparing differences in performance of similar oil producing assets.
Flare reporting and transparency	Usan	There is a significant variety in the level of disclosure and transparency by oil and gas companies on their emissions performance. Companies are encouraged to report flaring performance explicitly, on the basis of absolute metrics, such as amount of gas flared. Reporting should include ‘routine’ and ‘non-routine’ flaring as well gas flared from own operations and equity interest in assets operated by others.

Category	Asset	Description
Flare reporting and transparency	Usan	Early production performance review after start-up is good practice. The production period for startup analysis should not be determined by a fixed number of days, but by a confirmation of establishing stable operational performance. For Usan, it appears that this period is one year instead of 100 days. The production analysis should not only be based on oil deferments, but also include a review of gas flaring analysis as an indicator of a stable production process.
Flare reduction efforts	Usan	Distinction is needed between actual reductions in emissions and portfolio reductions. Remote measuring of emissions by satellites is an extremely valuable tool to assess flare performance of assets, regardless of transfer of operatorship or ownership.
Field Redevelopment	Bonga	Bonga Southwest development could set a new standard for reducing flare performance for other offshore installations. It is expected that some of the additional costs to establish ‘zero routine flaring’ will be recovered from additional revenues from gas utilization and LNG exports.
Field Redevelopment	Yoho	The redevelopment of Yoho into a gas field provides opportunity to rectify the existing structural production problems and flaring. New development design needs to be compliant with the commitment to stop routine flaring
Field Redevelopment	Yoho	With other offshore oil reservoirs depleting similar to Yoho, the FLNG facility could be successively redeployed to other field locations in accordance with their state of development maturity. Alternatively, more FLNG units could be redeployed simultaneously to Nigeria to further increase the country’s LNG supply through blow down of depleted oil fields
Other satellite applications for oil and gas field monitoring	Abo	Satellite data not only provide measurement and diagnostics of gas flaring performance, but are also instrumental in the detection and attribution of oil leaks due to offshore operations, as shown by the Sentinel satellite observation of a crude oil leak occurring from subsea infrastructure of the Abo field.

Appendix C: Key observations and conclusions from the performance evaluations of the five super-emitter assets

Agbami

Agbami is the largest of the super-emitter assets evaluated in terms of annual oil production. It is Nigeria's largest super-emitter flare and is ranked 39th among the world's largest flares during 2017-2021 and is globally the 4th largest FPSO in terms of flaring volume.

- Although Nigerian government has challenged JV partners Chevron and Equinor that Agbami is a gas field, the development does not include facilities to export produced gas to shore. Yet between 2004-2014, Chevron invested in other processing facilities that add value to onshore gas by converting it into liquids such as diesel, deliver it as domestic gas supply, and export gas through pipelines.
- Agbami was designed to be a 'zero routine flaring' facility in accordance with environmental policy, with all produced gas supposed to be reinjected into the producing reservoir for conservation. Yet until 2019, Agbami was focused on a strategy of maximum daily oil production rates which disregarded gas conservation.
- Analysis indicates that Agbami's flaring is mainly the result of lack of gas re-injection capacity, complemented by unstable production processes and consequent intermittent availability of gas compression facilities, particularly from 2017 onwards.
- Lack of gas re-injection is a likely contributing cause to Agbami's reservoir pressure decline, resulting in excess gas production and a steep oil production decline since 2018, increasing from 9 percent in 2018 to 19 percent in 2020.
- Gas flaring and overproduction may compromise the ultimate oil recovery of the Agbami field.
- The field operator Chevron has slowed oil production rates, and this reduced flare intensity (i.e. volume of gas flared divided by volume of oil produced) from 41 m^3/m^3 in 2018 to 28 and 26 m^3/m^3 in 2021 and 2022, respectively. However, this flaring intensity is considerably larger than the average 7.6 m^3/m^3 obtained during the period 2012 to mid 2016.
- Chevron is planning to install an upgrade to Agbami's gas injection facilities that are less vulnerable to process trips. Although this may assist in a reduction of natural gas flared, the analysis shows the majority of gas flared is not the result of incidental process trips, but due to wasteful operational procedures, complemented most likely by sustained unavailability of compression equipment.

Yoho

- Yoho is ranked 119th among the world's largest flares during 2017-2021 and is Nigeria's 7th largest in terms of flaring volume.
- Yoho was designed to be a 'zero routine flaring' facility in accordance with environmental policy, but this did not materialize.
- All produced gas is supposed to be reinjected into the producing reservoir for conservation and enhanced-oil recovery.
- Up to 2017, Yoho's oil production and gas flaring events are mostly negatively correlated, i.e. months with high gas flaring occur where oil production is down (and vice versa). This is predominantly the case when flaring is caused by operational performance issues such as process trips and equipment failures.
- From 2017 onwards, oil production and gas flaring are increasingly positively correlated, i.e. flare rates increase following increases in oil production. This performance is indicative of increased gas production and consequent flaring when oil wells exceed stable reservoir rates.
- Yoho's flare performance reflects a production policy to keep oil production at an annual target level, resulting in excess gas production and flaring at year end. Instead, it would have been better to operate strictly within a constant monthly flaring volume constraint.
- Yoho's moderate to high oil production decline (on average 11 percent per year) appears to have been mitigated since 2019 due to increased production restrictions to limit flaring.
- Periods of poor-quality flaring tend to occur when flare variability is high (due to process trips).
- Yoho is planned to be redeveloped from an oil field into a gas field using a floating liquefied natural gas (FLNG) facility, which will be Nigeria's first.

Usan

Usan is ranked 130th among the world's largest flares during the period 2017-2021 and as recent as 2021 it ranked 185th globally. It is Nigeria's 9th largest flare. It is a relatively recent deepwater development which came onstream in February 2012, which coincided with the start of VIIRS daily flare measurements that started from 1 March 2012 onwards. Therefore, among the Nigerian super-emitter assets evaluated, Usan is unique in that flare data are available for its complete production period, apart from the first week. It is also the only FPSO evaluated which changed operatorship, with Exxon taking over from Total in 2014.

- The development of Usan involved a record 60% of local content man-hours and thus has contributed to strengthening the know-how of the Nigerian industry in the area of hydrocarbon exploitation in the deep offshore. Over 500,000 engineering man-hours and 14 million construction and installation man-hours were performed in Nigeria. FPSO construction included an offshore integration of 3,500 tons of locally fabricated structures. In addition, large-scale training and capacity building programs were put in place, raising the skills of the local workforce to the benefit of future projects.

- There is a significant variety in the level of disclosure and transparency by oil and gas companies on their emissions performance. Flaring for Usan was particularly high during the first two years of production. Total S.A. group company particularly highlighted Usan's high flaring rates in its SEC reporting in 2013. According to Total S.A., Usan was then responsible for almost 20% of company's global flaring (i.e. 2 MMm3/d out of 10.8 MMm3/d) in 2013. Although Total has not revealed its reasons for its long-term intended sale of Usan, such a sale would have resulted in a decrease of reported flare volumes. However, the transfer of Usan operatorship from Total to Exxon in 2014, achieved the objective of portfolio decarbonization. With the transfer, Total no longer reports Usan's flaring, while Exxon does not report its gas flaring in its sustainability performance. Therefore, Usan flaring volumes seem to have disappeared from corporate reporting.
- By end 2022, Usan FPSO had flared in excess of 2 billion m3 of gas. This is 2.5 times more than Bonga and 82.5% of the volume flared by Agbami in the same 2012-2022 period, while cumulative oil recovered for Usan by end 2022 was less than a third compared to Bonga and Agbami.
- Usan's development drilling was completed in 2016 and this explains the low decline rates in this earlier production period. From 2018 to 2020, annual oil decline well exceeded 15% and reached 40.5% in 2020.
- By end 2022, Usan had produced close to 322 million bbl of oil. Decline curve analysis indicates that 80% of Usan's developed technical ultimate recovery for oil (440 million barrel) has been produced. The average annual oil decline rate is estimated at 15%.
- Usan increase in oil production decline in the period 2019-2021 coincides with an exceptionally high flare-intensity period (flare rate divided by oil production rate) and a marked increase in the number of poor-quality flaring events.
- Usan's flare intensity has been consistently higher compared to Agbami or Bonga. Earlier analysis on the Agbami asset showed that flare intensities at 30 m^3/m^3 and above correlate with high oil decline rates of 15% per year or more, while flare intensities below 10 m^3/m^3 correlate with low decline rates. Usan production has been at flare intensity levels consistently above 30 m^3/m^3 and therefore consistent with the overall oil decline rate of 15% per year.
- Usan's periods of poor flaring coincide with increased flare variability and oil decline rates in excess of the 15%.

Abo

Abo is the smallest in terms of annual production yet ranked 206th among the world's largest flares during the period 2017-2021 and 16th largest in Nigeria. Comparing flare performance across FPSOs, ('flare volume versus time') Abo is second only to Bonga - which is connected to the Nigeria LNG plant, in flaring the least volume of gas of the five assets.

- Abo gas processing capacities were not designed commensurate with a low or zero flaring policy. Installed gas production capacity is only 42% of the overall gas production capacity. It is no surprise therefore that gas flaring for Abo often is close to 60% of produced gas.
- Abo has flared a similar amount (close to 2 billion m^3) of gas as Usan over field life to date. Yet, by end of 2022, Abo had recovered 150 million bbl of oil, less than half of Usan's 322 million bbl of oil.
- Abo flaring in 2022 at 13.4 MMscf/d was the highest on record, despite low and declining oil production. However, when gas injection facilities are operational, as Abo demonstrated in 2014, it is possible to produce the field at lower flare rates (3.5 MMscf/d). The next lowest year of flaring was achieved in 2018 (at 6.6 MMscf/d), although at almost twice the rate in 2014 at half the oil rate.
- Abo's frequent development and subsea repair activities to maintain oil production make it difficult to establish remaining reserves through oil decline curve analysis. However, remaining reserves are estimated to range from 13 to 55 MMb of oil, with 76% to 92% of ultimate recovery already produced.
- Satellite data recorded a persistent oil leak likely to have originated from leaking subsea infrastructure of the Abo processing facility.
- Although the level of development activity reduced the overall field decline rate to 6.8% per annum, the field decline rate during no activity periods has over time increased from 15% to 35%. This implies that a significant level of oil development activity is required to maintain oil production from Abo.
- Abo's irregular production performance and high flaring performance demonstrate that Abo has not been performing in line with its development plans and approvals.

Bonga

Bonga demonstrated in its oil production policy that the company has limited oil offtake to safeguard the environment (flaring) and technical integrity. Bonga is ranked 348th among the world's largest flares during the period 2017-2021 and as recent as 2021 it ranked 258th globally. It is Nigeria's 22nd largest gas flare. Bonga is able to export its gas to Nigeria LNG (NLNG) a facility that is short of gas supply.

- Since its commissioning, Bonga has experienced various operational challenges, including oil spills, equipment failures, and issues related to gas flaring. These events have resulted in significant fluctuations in production levels and revenue.

- By end 2022, Bonga had flared 1.4 billion m^3 of gas which could have produced 855,000 tonnes of LNG, worth USD420 million at Q4 2021 gas prices. In 2021 alone, Bonga is estimated to have flared 125 million m^3 of gas, worth USD 37 million as LNG.
- Shell recognized that 2021 was a particularly poor year of flaring performance. In its global sustainability report, it made specific mention of Bonga's flaring.
- By end 2022, Bonga had produced 995.3 million bbl of oil. Decline curve indicates that 73% of Bonga's developed technical ultimate recovery for oil (1,360 million barrel) has been produced. Bonga's annual oil decline rate is estimated at 9.7% per year.
- Bonga poor-quality flaring observations appear to group in particular time segments, such as 2017 until early 2018, 2020 and 2022. Poor flaring also appears much more frequent in December-May period than during June-November.
- Bonga's flare intensity compared to Agbami is relatively low. Only in 2021 did Bonga's flare intensity rise to 20 m^3/m^3, a level where some negative impact in oil decline rate can be expected in 2023.
- The increasing frequency of potential poor flaring events in the period starting end 2019 indicates a likely degradation in emission performance. This coincides with the start of a new production phase when **r**outine flare rates increase significantly with longer duration periods of high peak flaring (due to structural equipment issues).
- Shell has committed to bringing forward the target to eliminate routine gas flaring from its Upstream operated assets from 2030 to 2025. This implies that there is less than three years for Shell to stop routine flaring in the assets it operates.

Appendix D: Abbreviations and Units

as applied in the various EnergyCC reports prepared for OPM/FOSTER Programme

APG	associated petroleum gas
API	American Petroleum Institute measurement of crude oil
bbl	barrel (1 bbl is 0.159 m^3)
bopd or bpd	barrels of oil per day
BC	black carbon
Bcm	Billion (= one thousand million) cubic meter
Bonga NW	Bonga North West
Bonga SW	Bonga South West
Btu	British thermal unit—measure of the energy content in fuel (1 Btu = 1.06 J)
CCAC	Climate and Clean Air Coalition
CDM	Clean Development Mechanism
CH_4	methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DFID	Department for International Development (UK)
DPR	Department of Petroleum Resources (Nigeria)
EPA	US Environmental Protection Agency
EPC	Engineering, Procurement and Construction
ESDD	Environmental and Social Due Diligence review
EU	European Union
FAAC	Federation Account Allocation Committee (Nigeria)
FCDO	Foreign, Commonwealth and Development Office
FLNG	Floating LNG facility
FOSTER	Facility for Oil Sector Transparency and Reform
FPSO	Floating Production Storage and Offloading
GGFR	Global Gas Flaring Reduction Partnership, led by World Bank Group

GHG	Greenhouse gas (such as carbon dioxide, methane, and others)
GMP	Global Methane Pledge
GOR	Gas-oil ratio
GTL	Gas to liquids
HFCs	Hydrofluorocarbons
ICPP	integrated combined cycle power plant
IOC	International Oil Company
IMF	International Monetary Fund
IPP	Independent Power Producer
IRR	Internal Rate of Return
JV	Joint Venture
Kbpd	thousand barrel per day (of liquids)
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	meter
m^3	cubic meter
Mln	Million
mm	millimeter (one-thousandth of a meter)
MMBtu	British thermal unit—measure of the energy content in fuel, 1 Btu = 1.06 J
MMscf/d	million standard cubic feet per day
Mscf	thousand standard cubic feet
mtpa	million tonne per annum
NAOC	Nigeria Agip Oil Company (a subsidiary company of ENI)
NAPIMS	National Petroleum Investment Management Services (Nigeria)
NBET	Nigerian Electricity Bulk Trader
NDC	Nationally Determined Contribution
NEITI	Nigeria Extractive Industries Transparency Initiative
NGL	natural gas liquids
NGO	Non-Governmental Organisation
NH_3	ammonia
NLNG	Nigeria LNG plant

NNPC	Nigeria National Petroleum Corporation
NOSDRA	National Oil Spill Detection and Response Agency
NO_x	chemical compounds made from elemental nitrogen and oxygen
NLNG	Nigeria LNG at Bonny Island
NUPRC	Nigeria Upstream Petroleum Regulatory Commission
OC	organic carbon (partially oxidized VOCs)
OGMP	Oil and Gas Methane Partnership
OPML	Oxford Policy Management Ltd
OML	Onshore Mining Lease
OPEC	Organization of Petroleum Exporting Countries
PPA	Power Purchase Agreement
SCAR	social cost of atmospheric releases
SCLP	short-lived climate pollutants
Scf/bbl	standard cubic foot of natural gas per barrel of crude oil
SDG	UN Sustainable Development Goal
SEC	Securities and Exchange Commission (USA)
SO_x	chemical compounds made from elemental sulphur and oxygen
SO_2	sulphur dioxide
SNEPCo	Shell Nigeria Exploration and Production company
SPDC-JV	Shell Petroleum Development Company joint venture
TCFD	Task Force on Climate-related Financial Disclosures
TEPN-JV	Total Exploration and Production Nigeria joint venture
UNEP	United Nations Environmental Program
UNFCC	United Nations Framework Convention on Climate Change
UNPR	United Nations Principles for Responsible Development
US$ or USD	United States dollar
VIIRS	Visible Infrared Imaging Radiometer Suite
VNF	VIIRS Nightfire. VNF is produced with data from VIIRS on board two satellites
VOC	volatile organic compound
WAG	Water-alternating-gas
XOM	Exxon Mobil company