Igniting Action to Reduce Gas Flaring:
Real Opportunities. Real Projects. Real Results.

Project Case Study:
Angola ALNG Facility

Columbia Center on Sustainable Investment
A JOINT CENTER OF COLUMBIA LAW SCHOOL AND COLUMBIA CLIMATE SCHOOL

capterio

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Context to this case study

This case study is part of a broader report by the Columbia Center on Sustainable Investment and Capterio, which analyzes gas flaring in depth. The report presents extensive findings and a practical set of actionable recommendations for governments, national oil companies, international oil companies, and other stakeholders. The full report and case studies are available here.

Despite bold commitments made over the past two decades, global gas flaring remains stubbornly high—at around 140–150 BCM per year—emitting up to 1 billion metric tons of CO_2-equivalent greenhouse gases annually, and representing as much as $30 billion per year in lost revenue.

We believe flaring reductions are not only technically achievable, but also commercially compelling. By capturing and using flared gas, companies and governments can increase revenue, enhance energy security, reduce emissions, and accelerate the energy transition. Among all decarbonization options, reducing gas flaring is one of the fastest and most cost-effective "quick wins."

Countries with high flaring levels can make substantial progress—if key commercial, organizational, and political challenges are addressed. Delivering flare-capture projects at scale requires a thoughtful, integrated, and collaborative approach, supported by strong leadership, aligned incentives, and a relentless focus on delivery over rhetoric.

The full report examines six case studies—including this one—to illustrate how flaring can be reduced. We go beyond analyzing the "what" and "why" of flaring, and focus on the "how" of unlocking and accelerating actual delivery. Three of these cases are project-based examples from Angola, the Kurdistan Region of Iraq, and Argentina, where flared gas has been successfully captured and used. The other three country-based studies—covering Federal Iraq, Egypt, and Algeria—highlight both progress and untapped opportunities.

The full report also explores the systemic barriers to progress, the lessons learned from the case studies, together with some innovative life-cycle considerations for greenhouse gas emissions, and a detailed set of recommendations.

We encourage readers of this case study to explore the broader report and the other case studies. Together, we hope they offer a meaningful contribution to global efforts to end routine gas flaring.

Executive Summary

Angola ALNG case study

Angola's LNG (ALNG) project was a first-of-a-kind LNG project designed principally to monetize flared associated gas for domestic use and international export. While the project had some setbacks in earlier years (leading to some commercial challenges), it has successfully monetized material volumes of liquefied natural gas and lowered emissions. The high degree of integration between upstream and downstream coupled with flexibility in fiscal treatment by the government of Angola was instrumental to this project being approved.

- Angola is a major oil-producing nation. Historically, it has also had high gas flaring, largely because of the lack of a domestic gas market for natural gas. Gas flaring started to reduce in the late 1990s, driven by a number of dedicated efforts. The development of a global gas market through liquefaction also provided new opportunities to transform what had been a waste product into a usable energy resource.
- The Angola LNG (ALNG) project, conceived in 1997, was the first of its kind. It was designed to capture associated gas from the offshore oil fields, decades ahead of global commitments to mitigate gas flaring. Many technical and commercial barriers needed to be addressed for this project to proceed.
- Strong leadership from equity owners, including Sonangol and Chevron as the lead partner, coupled with proactive coordination between upstream and midstream players and creative fiscal structuring from the government, was instrumental in overcoming considerable complexity.
- ALNG has made a significant environmental contribution, reducing emissions from the oil supply chain by some 15%, or up to 39 million carbon dioxide (CO_2)-equivalent metric tons per year. In addition, the project has created jobs, reduced local pollution, supported the Angolan economy, created value, and improved domestic and international energy security.
- The economic and commercial outcomes were, however, considerably less attractive than expected on project sanction, in part because of many technical and operational challenges that can be attributed to project design, execution, and governance.
- Looking forward, Angola has an opportunity to further drive decarbonization, create commercial value through new investments to capture and monetize additional flared gas, and continue to drive improvement in operational performance (especially through critical equipment maintenance). Two projects are already under development to increase gas supply (from associated and non-associated gas) to ALNG by 2026, with additional projects under evaluation.
- The insights and lessons outlined in this paper could benefit similar flare-gas capture projects, offering scalable solutions to reduce flaring, generate value, and accelerate the energy transition. In addition, strengthening international carbon pricing mechanisms could further align incentives and mobilize capital at scale, helping to drive these efforts forward.

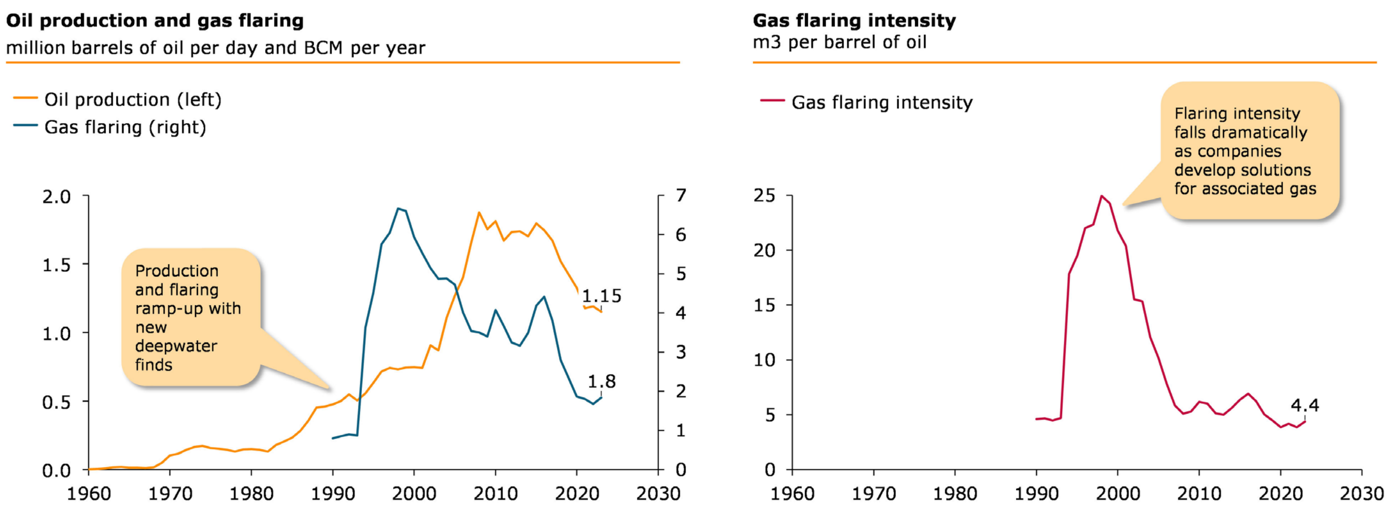
The Rise of Angola as a Major Oil Producer and Its Link to Gas Flaring

Angola is the 18th-largest oil-producing nation, with production reaching 1.1 million barrels per day in 2023. According to the World Bank, it flares about 1.8 BCM of gas annually,[1] which equates to a flaring intensity of 4.4 m³ per barrel—slightly below the global average of 5 m³ per barrel and lower than neighboring producers, such as Nigeria, Gabon, and Equatorial Guinea. If methane emissions from venting and leaking, plus those from incomplete combustion at flares, are included (1.2 BCM in 2024, according to the 2025 International Energy Agency's Methane Tracker[2]), there is an opportunity to capture an additional 3.1 BCM of gas per year. At $10 per MMBtu, this gas could generate revenues of $1.1 billion per year.

Angola's political landscape was shaped by the civil war[3] (from 1975 to 2002) that followed independence from Portugal and its rise as a prolific oil producer. Despite the conflict, Angola emerged as a key exploration frontier, with Sonangol (Angola's national oil company, established in 1976) playing a central role in managing its oil resources. By 2007 (the year of ALNG's Final Investment Decision, FID), oil accounted for 52% of Angola's gross national product, 95% of its exports, and 80% of government revenue.[4]

Angola's recent success was led by greenfield exploration. The introduction of 3D seismic technology in the 1990s unlocked a major deepwater province, leading to world-class discoveries of high-quality light oil by companies, including Chevron, TotalEnergies, ENI, ExxonMobil, Statoil (now Equinor), and bp. Chevron operated the first deepwater well, which started production from Block 14 in 2000. Oil production soon ramped up in the early 2000s, accompanied by a corresponding rise in the flaring of associated gas (as shown in Figure 1).

Gas flaring and gas flaring intensity has dramatically declined in Angola



Source: World Bank; Capterio FlareIntel.

Figure 1: Oil production and gas flaring in Angola (left). Oil production accelerated from the early 1990s, after the success of exploration in the prolific deepwater basin. Gas flaring similarly ramped up, but initiatives (outlined below) starting in the early 2000s dramatically reduced Angola's gas-flaring intensity (i.e., gas flaring per barrel of oil production; right chart).

1 World Bank Group. (2023). *Global gas flaring tracking report*. https://www.worldbank.org/en/programs/gasflaringreduction/publication/2023-global-gas-flaring-tracker-report.
2 International Energy Agency. (2025). *Global methane tracker 2025*. https://www.iea.org/reports/global-methane-tracker-2025.
3 Clarence-Smith, W. G., & Thornton, J. K. (2025). Angola. *Encyclopaedia Britannica*. https://www.britannica.com/place/Angola.
4 U.S. Department of State. (2017). Angola (07/08). https://2009-2017.state.gov/outofdate/bgn/angola/111337.htm.

Under the terms of the production sharing agreement (PSA)[5]—consistent with many international frameworks—gas flaring was prohibited, with penalties in place for noncompliance.[6] However, these flaring penalties have rarely been enforced (since doing so would have necessitated curtailing oil production, reducing national revenues and potentially compromising loan repayments).

Ownership of any associated gas was automatically granted to Sonangol,[7] but there was also an absence of a clear legal and contractual framework to promote the commercialization of gas development. Specifically, at the time, there was no clarification on the fiscal terms for the commercialization of associated gas in the PSA or concession contracts. There was also a key difference between the PSA and concession blocks. In the latter, the equity holders had full flexibility over the use and commercialization of the gas; in the PSA, approval was required.

Nevertheless, by the late 1990s and early 2000s, the Angolan government began expressing concern about the waste from gas flaring, indicating that future oil projects would not be sanctioned without structural commercial solutions to reduce flaring. The government was also eager to channel some of the flared gas into domestic use, particularly to support power generation and butane projects, given the country's low electrification rate—only 26% in 2009, leaving 14 million people without electricity.[8] Additionally, the government sought to supplement Angola's sometimes-unreliable hydropower supply, which provided over two-thirds of the country's electricity in 2011.[9]

Gas-Flaring Reduction Initiatives from the Early 2000s

Gas flaring has been a part of Angola's oil industry since production began in shallow water blocks in 1969. As shown in Figure 1, flaring rose (according to data from public domain sources) during the 1990s, commensurate with increased oil production, peaking at 6.7 BCM in 1998.

Some flare-reduction efforts started in the early 1980s, such as extracting liquefied petroleum gas (LPG) as part of the Cabinda gas project, operated by Chevron. By the late 1990s and early 2000s, flare-mitigation efforts advanced with at least three more initiatives.

First, flared gas was injected into reservoirs to support enhanced oil recovery (EOR) and conserve it for future use. This practice was implemented in fields like Takula, Nemba, Lomba, and Malongo.[10] Second, starting in 2005, gas from the Sanha and Bomboco fields in Block 0 was recovered for the Sanha gas and LPG project, which produced LPG,

5 Chevron's Block 0 contract (the shallow water field dominating pre-2000 production) was an exception and a concessionary agreement.

6 Flaring was forbidden under Article 73 of the Petroleum Law of 2004; however, the Ministry of Petroleum routinely granted exceptions to permit flaring. See: Oswald, M., Kojima, M., De Sa, P., Gulen, G. S., & Pollard, A. (2022). *Global flaring and venting regulations: 28 case studies from around the world*. https://thedocs.worldbank.org/en/doc/fd5b55e045a373821f2e67d81e2c53b1-0400072022/related/Global-Flaring-and-Venting-Regulations-28-Case-Studies-from-Around-the-World.pdf.

7 Natural Resource Governance Institute. (n.d.). Angola: Production sharing agreement between Sociedade Nacional de Combustíveis de Angola - Empresa Pública (Sonangol, E.P.). https://resourcegovernance.org/sites/default/files/Angola%20PSA%20Template.pdf.

8 Parker, M., & Kreuze, H. (2014). *Angola and Mozambique gas monetization for economic development. DNV KEMA Energy & Sustainability.* https://www.afdb.org/fr/documents/document/angola-mozambique-gas-monetization-for-economic-development-project-study-full-report-47447.

9 Parker, M., & Kreuze, H. (2014). *Angola and Mozambique gas monetization for economic development. DNV KEMA Energy & Sustainability*. https://www.afdb.org/fr/documents/document/angola-mozambique-gas-monetization-for-economic-development-project-study-full-report-47447.

10 Beckman, J. (2003). "Multi-field condensate project will re-vamp Angola block 0 gas management," Offshore Magazine. https://www.offshore-mag.com/production/article/16755557/multi-field-condensate-project-will-re-vamp-angola-block-0-gas-management.

gas condensate, and butane for local consumption and export.[11,12] Third, Chevron began capturing associated gas to fuel gas-fired power plants, such as the Malongo power plant. By 2006, Chevron had also invested $1.5 billion to eliminate routine flaring in selected assets by 2006.[13] These initiatives were key to the government granting an extension of Chevron's Block 0 license in 2004 as evidenced by gas-flaring reduction actions required under Decree Law 2/04 of 2004.

By the mid-2000s, several operators in Angola had adopted "zero routine" or "zero flaring during steady operations" policies, with at least one operator committing to halting production if upset flaring conditions persisted beyond 72 hours.

However, a more comprehensive approach was needed to reduce flaring and monetize this wasted gas, leading to the conception of the ALNG project. The government also knew that it would need to overcome significant barriers to turn flaring into an opportunity that creates value, reduces emissions, and supports the economy.

Overcoming Barriers to Deliver Decarbonization Opportunities

Despite clear progress in reducing gas flaring in Angola during the early 2000s, several issues needed to be overcome to turn flaring into an attractive and investable opportunity, including:

- **Technical issues:** Existing methods including gas injection and recovery for power or LPG projects helped reduce flaring, but a more comprehensive structural solution was needed. The new deepwater oil fields were particularly complex, with higher gas-oil ratios, medium to high sulfur content (e.g., 0.8 weight percentage in Saturno and 0.9 weight percentage in Kuito) and high acidity (Total Acid Number >1 mg KOH/g in Pazflor).[14] The offshore environment, especially in northern Angola, also required operating within the Congo River Canyon, one of the largest submarine canyons in the world.[15] Furthermore, the deepwater fields were expected to face steep decline rates after their initial production plateau, which created uncertainty about future gas availability.
- **Economic uncertainty:** Angola's economy was heavily dependent on oil revenue, which was essential for repaying oil-backed international loans and financing postwar recovery efforts. Reducing oil production to minimize flaring, a policy proposed by at least one major operator, was economically unworkable.
- **Commercial complexity:** Exploration success in the 1990s and frequent licensing rounds fragmented offshore acreage into numerous blocks, each with different ownership structures, contracts, and gas title agreements. Most international operators did not own the gas under their production-sharing contracts (PSAs) and were required to deliver it to Sonangol for free. This lack of commercial incentive, combined with a lack of a domestic market and challenges in financing—especially for Sonangol's share—complicated efforts to reduce flaring. Despite this, the imperative to start production was clear, especially given the large signature bonuses paid by the

11 Chevron. (2006). *2006 Supplement to the Annual Report*. https://media.corporate-ir.net/media_files/irol/13/130102/reports/cvx_arsupplement_2006_rev.pdf.

12 Chevron. (2006). *Corporate responsibility report 2005.* https://www.responsibilityreports.com/HostedData/ResponsibilityReportArchive/c/NYSE_CVX_2005.pdf.

13 Chevron. (2014). *2014 Supplement to the Annual Report.* https://www.chevron.com/-/media/shared-media/documents/chevron2014annualreportsupplement.pdf.

14 BP. (n.d.). Crude assays. https://www.bp.com/en/global/bp-trading-and-shipping/documents-and-downloads/technical-downloads/crudes-assays.html; Equinor. (n.d.). *Crude oil assays*. https://www.equinor.com/energy/crude-oil-assays.

15 Encyclopedia Britannica. (1998). Congo canyon. https://www.britannica.com/place/Congo-Canyon; Heezen, B. C., Menzies, R. J., Schneider, E. D., Ewing, W. M., & Granelli, N. C. L. (1964). Congo submarine canyon. *AAPG Bulletin 48*(7), 1126–1149, https://doi.org/10.1306/BC743D7F-16BE-11D7-8645000102C1865D.

international investors. A gas law in 2018 (Presidential Decree No. 7/18)[16] provided an improved workable gas commercialization framework.

- **Organizational alignment:** Gathering associated gas involved coordinating upstream production, transportation, liquefaction plants, and target markets, making it a highly complex project. Aligning multiple operators across different cultures and geographies added complexity.
- **Political and geopolitical context:** Angola, still recovering from decades of civil war, faced many ongoing political challenges and was labeled a high-risk country by many. Complexity was increased by the presence of an exclave of the Democratic Republic of Congo separating the northern offshore blocks in Cabinda from the main part of Angola. As an OPEC member, Angola also did not have (until it left the cartel, effective from January 1, 2024[17]) full control of its oil production, and hence, its associated gas.

The Genesis of ALNG: a First-of-Its-Kind Flared to LNG Project

(a) Project Overview

The ALNG project was conceived in 1997 by Texaco (the original operator of Block 2, before Chevron's acquisition in 2001) as a solution to address the gas-flaring challenge.[18] Texaco's proposal was one of several responses to Sonangol's call for ideas to monetize flared gas. Other proposed options—including continued flaring, halting oil production, gas reinjection, and various gas monetization methods like gas-to-liquids, fertilizer, methanol, and gas pipelines—were ruled out in favor of LNG, which was deemed the best from a technical and commercial alternative.

The original objective for ALNG was "to eliminate gas flaring through the development of a profitable, competitive, and integrated gas solution, allowing the booking of reserves, timely oil development, and contribution to the social and economic development of Angola."[19] Sonangol strongly supported the concept, encouraging Chevron to develop it, a move that aligned with negotiations to extend Chevron's Block 0 concession.

Led by Chevron and Sonangol, ALNG became the world's first LNG plant dedicated to monetizing flared (associated) gas. The project integrated upstream and midstream development, including 360,000 m^3 of storage capacity at Soyo. ALNG was designed to process 1.1 billion scf per day (about 11 BCM per year), producing up to 5.2 million metric tons per year of LNG (equivalent to 6.8 BCM of gas), along with 63,000 barrels per day of natural gas liquids and LPG and 125 million scf per day of domestic gas.[20]

The project's equity partners include Chevron (36.4%), Sonangol (22.8%), and bp, ENI, and TotalEnergies (13.6% each). Original partners Equinor and ExxonMobil exited in the early 2000s, citing commercial concerns.

16 Presidential Legislative Decree No. 7/18 establishing the legal and fiscal regime applicable to the activities of prospection, research, evaluation, development, production and sale of natural gas in Angola, https://faolex.fao.org/docs/pdf/ang178698.pdf.

17 Mendes, C., & Burkhardt, P. (2024). Angola left OPEC to help sustain oil production above 1 million barrels a day. *Bloomberg*. https://www.bloomberg.com/news/articles/2024-01-03/angola-left-opec-to-help-sustain-oil-production-above-1-million-barrels-a-day.

18 Angola LNG. (2022). *Our history & overview*. https://www.angolalng.com/about-angola-lng/our-history-overview.

19 Angola LNG. (2005). *Proposed Angola LNG project environmental, socioeconomic, and health impact assessment (ESHIA): Scoping phase supporting document*. https://www.biofund.org.mz/wp-content/uploads/2018/11/F1228.Scopingreport-Nb.pdf.

20 Angola LNG. (2022). About Angola LNG. https://www.angolalng.com/about-angola-lng.

The Front-End Engineering Design contract was awarded to Bechtel in 2005. At the time, it was its largest lump-sum contract.[21] The LNG plant's design licensed the "Optimized Cascade Process" by ConocoPhillips, capable of handling diverse gas compositions. The project employed 3,000 to 5,000 staff members during construction, and up to 50 Angolans were trained—mostly in the United States and Europe, starting in 2009—in technical aspects of LNG.[22] By 2013, some 500 permanent staff were employed.

Upstream development included complex offshore gas-gathering systems supported mostly by FPSO (floating production storage and offloading) vessels. Phase 1 involved subsea pipelines from southern Blocks 15 (operated by ExxonMobil), 17 (TotalEnergies), and 18 (bp), while a second 140 km pipeline brought flared gas from Blocks 0 and 14 (Chevron). The challenging Congo Canyon terrain complicated the construction of the pipeline to the north (which was completed by 2016) and helped reduce flaring by 2018. In total, 500 km of pipelines were built. Upstream partners bore the upstream costs for gas gathering, compression, transportation, and pipelines as part of their license obligations. Sonangol took over pipeline ownership to reduce future commercial complexity.

To ensure project longevity and to reduce the project's risk, Sonangol granted, in principle, at least, ALNG partners access to "make up" non-associated gas from relinquished parts of Block 2 (although this has not yet been delivered). Make-up gas was deemed particularly important to ensure reliable supplies of associated gas, especially given that gas supplies to the ALNG plant are vulnerable to both uncertainties in oil production in complex deepwater fields,[23] and possible production curtailment (through Angola's membership, until late 2024, of OPEC). Additionally, the government facilitated the project's economics by offering preferential tax treatment, including a 12-year tax exemption and a 35% corporate tax rate for the LNG plan—lower than the 65% to 90% marginal take under the PSAs.[24]

Initially, ALNG's long-term LNG supply contracts were designed for export to the United States, which, at the time of FID in 2007, was the fourth largest importer of LNG (22 BCM per year), behind Japan, South Korea, and Spain.[25] These contracts were supported by ALNG's fleet of seven LNG tankers[26] and included long-term throughput agreements that secured capacity at a dedicated regasification terminal in the Gulf of Mexico. They also facilitated the deepening of the port in Mississippi to accommodate LNG shipments.

However, by 2013, the surge in US shale gas production had nearly eliminated the need for LNG imports, and by 2016, the US had transitioned to being a significant LNG exporter, fundamentally shifting the global LNG market. In response, ALNG adapted by selling its LNG on the more lucrative European and Asian spot markets, while also negotiating exits from several downstream contracts. This strategic pivot to spot market sales not only maximized revenue by targeting higher-priced markets but also provided a crucial outlet for gas that may have struggled to secure long-term contracts at favorable prices. This was particularly important during the early stages when the reliability of an associated gas project had not yet been fully proven.

21 Bechtel. (2013). *The Bechtel report 2012*. https://www.bechtel.com/getmedia/69dc81ba-45d8-4e1f-b64e-aee97150a18c/2012-bechtel-annual-reportb93c.pdf.

22 Manyuchi, A. E. (2016). Foreign direct investment and the transfer of technologies to Angola's energy sector. *Africa Spectrum*, 51(1), 55–83. https://www.jstor.org/stable/pdf/43941304.pdf?refreqid=fastly-default%3Af489f734e9a65455e04cb49cadc4fe5b&ab_segments=&initiator=&acceptTC=1.

23 For example, this started to falter in mid-2013 because of technical problems and saltwater issues in BP's Plutonio fields, plus an attack by a 14-foot blue marlin. Fattouh, B., & Sen, A. (2014). *New swings for West African crudes*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/08/New-swings-for-West-African-crudes.pdf.

24 Republic of Angola. (2007). *Project decree law 10/07*. Chapter II Section I. https://faolex.fao.org/docs/pdf/ang120485.pdf.

25 Mike Fulwood, *What Drives International Gas Prices in Competitive Markets? Four Fallacies and a Hypothesis* (Oxford: Oxford Institute for Energy Studies, October 2024), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/10/NG-195-What-Drives-International-Gas-Prices-in-Competitive-Markets.pdf.

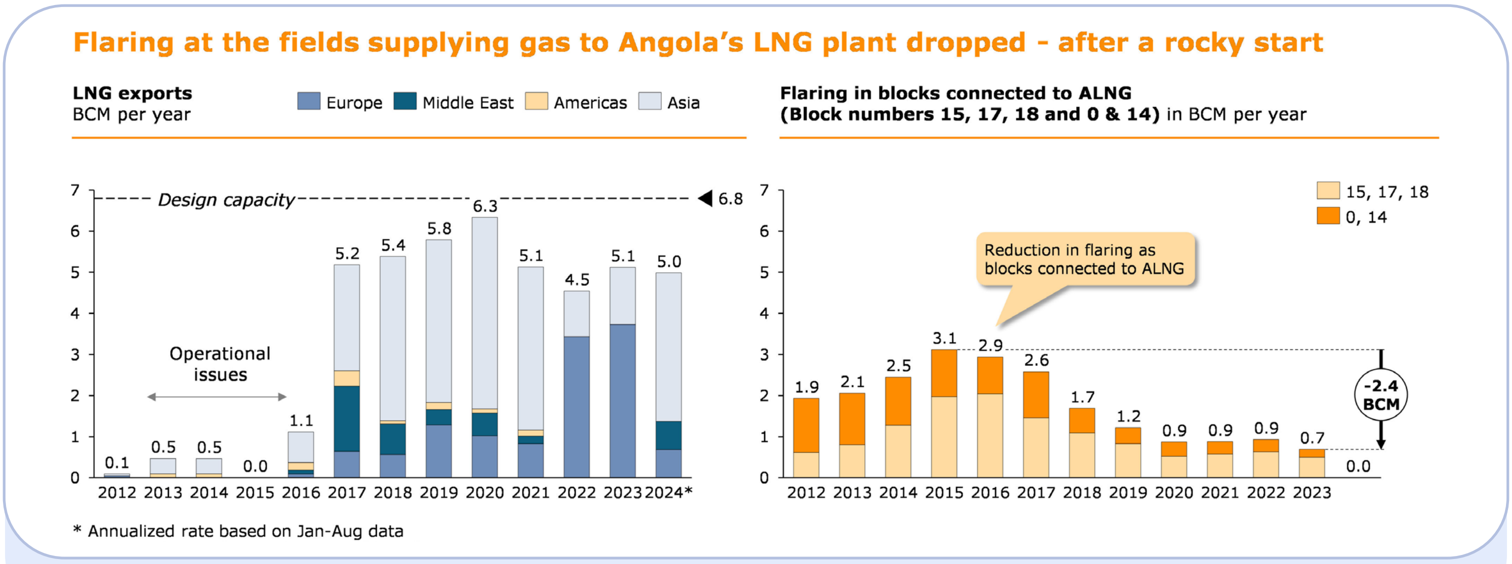
26 Lucy Corkin, *After the Boom: Angola's Recurring Oil Challenges in a New Context* (Oxford: Oxford Institute for Energy Studies, May 2017), https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/After-the-Boom-Angolas-Recurring-Oil-Challenges-in-a-New-Contect-WPM-72.pdf.

The use of spot market sales was a strategic choice that might not have been feasible with project-based financing, as financiers typically require the security of long-term contracts. However, Sonangol was able to pursue this strategy because its share of the project was funded through equity-based financing, which did not impose such restrictions on spot sales. Additional financing, notably for the International Oil Company partners, came from a combination of company equity, export credit agencies, development finance institutions, and commercial banks.

The FID was made in 2007 (the same year that Angola joined OPEC), and construction started in 2008. The original $9.2 billion budget expected at FID was one of the largest investments in the Angolan oil and gas industry.[27] Start-up was planned for 2011, but delays pushed this to 2013.

On June 15, 2013, Angola became the 19th country to export LNG, with its first cargo destined for Brazil. In 2021, 77% of ALNG's exports were directed to Asia and 16% to Europe[28]—a share that surged to 75% in 2022[29] to help stabilize Europe's energy supply during the Russia-Ukraine war (see Figure 2). ALNG has now supplied LNG to 26 countries whilst also materially reducing gas flaring since 2016.[30]

Figure 2 shows both the profile of LNG exports over time and the flaring within the blocks that supply the gas to the ALNG plant. As shown, the plant has almost never operated at full design capacity, suggesting a constrained supply of gas (despite the government's commitment to ensure "makeup" gas was available).



Source: Kpler; Author analysis; World Bank.

Figure 2: Angola's LNG output from ALNG by destination plus gas flaring from the blocks that supply gas to the LNG project. The reduction in flaring (some 2.4 BCM) is lower than the LNG exported (discussed below). Flaring data from World Bank. LNG export data (and destination) from Kpler.

(b) Estimation of the total gas involved in the LNG system

To gain a comprehensive understanding of the commercial and environmental implications of ALNG (see next section), we have estimated the total gas volume involved across the whole system that relates to the project. In 2023, delivering 5.4 BCM of LNG—when

27 Fulwood, M. (2024). *What drives international gas prices in competitive markets? Four fallacies and a hypothesis*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/10/NG-195-What-Drives-International-Gas-Prices-in-Competitive-Markets.pdf.

28 Angola LNG. (2022). *Home*. https://www.angolalng.com/.

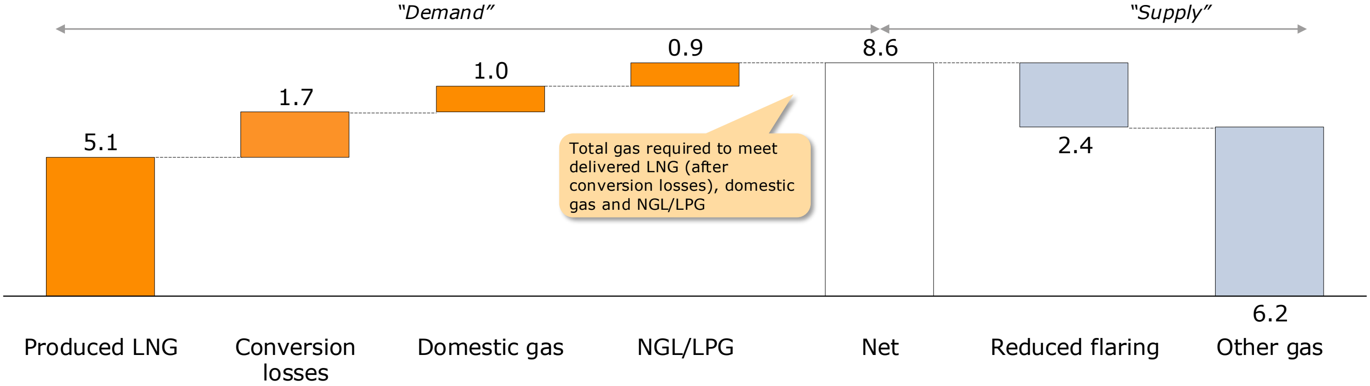
29 Data on LNG cargos from Kpler, analyzed by author.

30 Angola LNG. (2022). *Home*. https://www.angolalng.com/.

accounting for conversion losses,[31] domestic gas and NGL/LPG—required the system to supply an estimated 8.6 BCM of gas to the LNG plant. See Figure 3 (left-hand side). Since the observed reduction in flaring in the blocks that supply gas to the LNG plant is only 2.4 BCM, we conclude that the reduction in flaring alone was insufficient to meet the plant needs, and therefore another source of gas ("other gas") must have been supplied, as discussed below.

The strong demand for gas within the ALNG system is met in part by captured flared gas

Gas volumes (BCM, shown for the year 2023)



Produced LNG	Conversion losses	Domestic gas	NGL/LPG	Net	Reduced flaring	Other gas
▪ Resulting LNG exported from the ALNG facility	▪ Conversion losses (e.g. for power generation for compression and cooling)	▪ Supplied domestic gas obligation	▪ Likely LPG delivered		▪ Observed reduction in gas flaring	▪ Implied other gas supplied to meet the volumes processed by ALNG

Source: Capterio analysis; ALNG.

Figure 3: Reconciliation of the supplied volumes of gas to the ALNG system in the year 2023. Gas supplied to the ALNG comes in part from a reduction in gas flaring (by 2.4 BCM). Based on ALNG's figures, 5.2 million metric tons per year (equivalent to 6.8 BCM of gas) requires 1.1 billion scf per day (or 11.4 BCM), implying an upscaling factor account for conversion losses, domestic gas, and produced LPGs. We estimate that 6.2 BCM of other gas would be required to deliver 8.6 BCM of gas, which, after losses, result in LNG exports of 5.1 BCM (3.8 million metric tons per year).

This "other gas" is perhaps sourced from gas not previously flared, which could include (a) recovery of previously injected or stored gas, (b) additional associated gas from increased oil production or gas-rich oil fields in existing or new fields, or from fields in Block 31 (initially not destined to the ALNG project), (c) non-associated gas from other producing fields (although planned, this has not happened yet), or (d) gas previously vented as methane (which would not be detected by satellites as flaring). Alternatively—although something we consider unlikely—the gas flaring figures from the World Bank could be materially underestimated. We think that the majority of the additional ("other") gas came from a combination of recovery of reinjected gas and from increased oil production.

31 We estimate the conversion losses from the basic data provided by ALNG, which identifies that the design specification has 1.1 bcf/day of gas delivered to the ALNG plant which also supplies 125 million scf per day of gas to domestic markets and 63,000 barrels per day of LPG. We have scaled these numbers down to reflect that in 2023 the LNG export was 5.1 BCM (not the capacity figure of 6.8 BCM). We have assumed that some 10% gas shrinkage results from the extraction of LPG.

ALNG Main Outcomes: Operational, Economic, and Environmental

We explore the main outcomes of the ALNG project in terms of the environmental outcome, the operational performance, and the economic return to investors and other stakeholders.

(a) Operational Outcomes

In 2003, Wood Mackenzie described the project as one that “holds great promise” but also warned of challenges, particularly regarding gas sourcing and projected start-up timelines. As it turned out, several operational issues—reportedly including design flaws[32]—led to delays, pushing back the plant’s start-up and its first LNG export, which eventually took place in June 2013.

Early operations faced significant challenges. In April 2014, the plant experienced an operational shutdown, followed by a series of incidents, including a control room fire, pipeline leaks, the loss of a drilling rig (tragically resulting in a fatality), and issues with dehydration equipment. Additionally, the gas feedstock composition necessitated unplanned equipment upgrades, while the high-salinity environment accelerated corrosion of the steel infrastructure.[33]

While the plant was offline or running at low capacity, at least one upstream partner drilled an additional reinjection well to reduce flaring and overall emissions from their oil production.[34] However, the overall impact of the shutdown was to increase flaring (Figure 3) and create cost overruns—reportedly reaching $3 billion—raising the estimated final capital expenditure to $12 billion.[35] Yet, despite these overruns, a Financial Times analysis found that, at the time of the article, in 2012, ALNG’s capital cost ($1.7 billion per million metric tons of annual capacity—equivalent to $33 per mmbtu of capacity) was competitive compared to some other major LNG projects.[36]

From 2012 to 2016, ALNG’s operational challenges led to the plant operating at around 10% of its intended capacity. However, since 2016, operational performance has stabilized, though the plant continues to run well below design capacity—likely due to challenges in sourcing gas from mature offshore oil fields[37] through pipelines built under the Congo River.[38]

As of August 2024, according to Kpler,[39] which provides vessel-tracking services, the project had exported over 470 cargoes (averaging 54 per year over the last 3 years, with each cargo containing 0.15 BCM of LNG). The project also supplies 125 million scf per day of gas and butane to domestic markets, along with over 200 shipments of LPG and condensate to domestic and international markets. ALNG has also become the primary gas supplier to the Soyo power plant, which integrates with the central and northern regions of Angola.

32 Vukmanovic, O., & Laxmidas, S. (2014). Exclusive: Reconstruction at Angolan plant chills liquefied gas project. *Reuters*. https://www.reuters.com/article/markets/oil/reconstruction-at-angolan-plant-chills-liquefied-gas-project-idUSL6N0QE26P/; Corkin, L. (2017). *After the Boom: Angola’s recurring oil challenges in a new context*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/05/After-the-Boom-Angolas-Recurring-Oil-Challenges-in-a-New-Contect-WPM-72.pdf.

33 Gismatullin, E., & Patel, T. (2014). Total’s Angola LNG ‘disappointment’ worsens shortfall. *Bloomberg*. https://www.bloomberg.com/news/articles/2014-06-17/total-s-disappointment-with-angola-lng-adds-to-output-gap?embedded-checkout=true.

34 BP. (2015). *BP in Angola sustainability report 2014* BP https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/sustainability/archive/archived-country-reports/angola/sustainability-report-2014-angola.pdf.

35 Angola LNG. (n.d.). About Angola LNG. https://www.angolalng.com/about-angola-lng.

36 Hume, N. (2012). Australia set to take its place on LNG stage. *Financial Times*. https://www.ft.com/content/3adce71e-8d9f-11e1-b8b2-00144feab49a.

37 International Trade Administration. (2024). *Angola – country commercial guide*. U.S. Department of Commerce. https://www.trade.gov/country-commercial-guides/angola-oil-and-gas.

38 Roelf, W. (2024). Angola LNG considers expansion as gas supplies ramp up. *Reuters*. https://www.reuters.com/business/energy/angola-lng-considers-expansion-gas-supplies-ramp-up-2024-11-08/.

39 Kpler. (n.d.). *The go-to source for global trade intelligence*. https://www.kpler.com.

(b) Economic outcomes

Understandably, the project delays, cost overruns and lower-than-planned peak LNG output negatively impacted the economic outcome of ALNG—although forward-look economics are considerably more attractive. Unfortunately, the plant's low LNG output coincided with a tight LNG market, in which prices were set largely by marginal costs and—for Asian oil—high prices determined by high oil prices. We estimate that these outages resulted in a cumulative revenue shortfall of around $13 billion.[40]

Nevertheless, based on exported volumes[41] and spot-market LNG prices, we estimate the cumulative LNG revenue by the end of 2023 to be $15 billion. To this, we add an estimated $5 billion of revenue from sales of LPG (based on 250 likely cargoes by the end of 2023)[42], and note that domestic gas provides additional revenues.

Accounting for operating expenses,[43] we estimate that—on a life cycle basis—the project became cash-positive on a cumulative undiscounted basis in the early 2020s. Accounting for the time value of money, we suggest that the discounted capital expenditure is greater than the discounted revenue, leading to a life cycle project internal rate of return (IRR) in the low single digits (on a pre-tax basis)—well below the investors' expectations at FID.

However, as discussed below, the ALNG project also enabled the successful development of deepwater oil fields, helping to sustain production levels (see Figure 1) and increasing revenues for both the government and offshore partners.

Crucially, Sonangol and the Angolan government have benefited not only from oil revenues—via production sharing, royalties, and taxes—but also from their equity stake in the LNG liquefaction plant. However, direct tax revenue from the LNG project itself has likely been minimal due to underperformance and fiscal incentives granted to ALNG equity partners.

(c) Environmental

Despite never reaching its design capacity, ALNG has helped Angola reduce flaring by 73% since its peak in 1998 and played a key role in Angola endorsing the World Bank's Zero Routine Flaring by 2030 initiative in 2016. While a detailed inventorisation and analysis of the emissions are beyond the scope of this paper, we explore the likely emissions impact on the project—noting that by reducing flaring, emissions of methane are also reduced.

To estimate the emissions impact of the ALNG project, we have attempted to compare the "current situation" (gas capture plus some residual flaring) with the "counterfactual" or reference case (where all the gas would have been flared).

- Specifically, in the current situation we account for 10.5 BCM per year of gas, which comprises firstly of the emissions associated with the recovered gas (some 8.6 BCM per year, as per Figure 3)—which we assume is combusted by the end user, with a net combustion efficiency of 98%.[44] To this, we add the emissions associated with the remaining flaring (some 1.8 BCM), which we assume has a combustion efficiency of 95%.[45,46]

40 Calculated using actual Asian LNG prices (which were mostly driven by the high oil prices and oil indexing of gas prices) and production at design capacity.

41 Determined from a detailed analysis of the loadings of each LNG vessel using Kpler data.

42 We assume that the 250 cargoes have an average scale of 75,000 m^3 and an LPG density of 510 kg/m^3. Based on the total LNG exports of 39.6 BCM by end of 2023, this is yield of 0.24 million metric tons of LPG per BCM, which amounts to LPG production at peak of some 51,000 barrels per day. For pricing, we assume LPG prices are 65% oil, amounting to an average of $550 per metric ton of LPG.

43 This estimate is, at maximum, 4% of cumulative capital expenditure (i.e., some $450 million per year), but it is likely to have fixed and variable elements. The main outcome, however, is not particularly sensitive to this assumption.

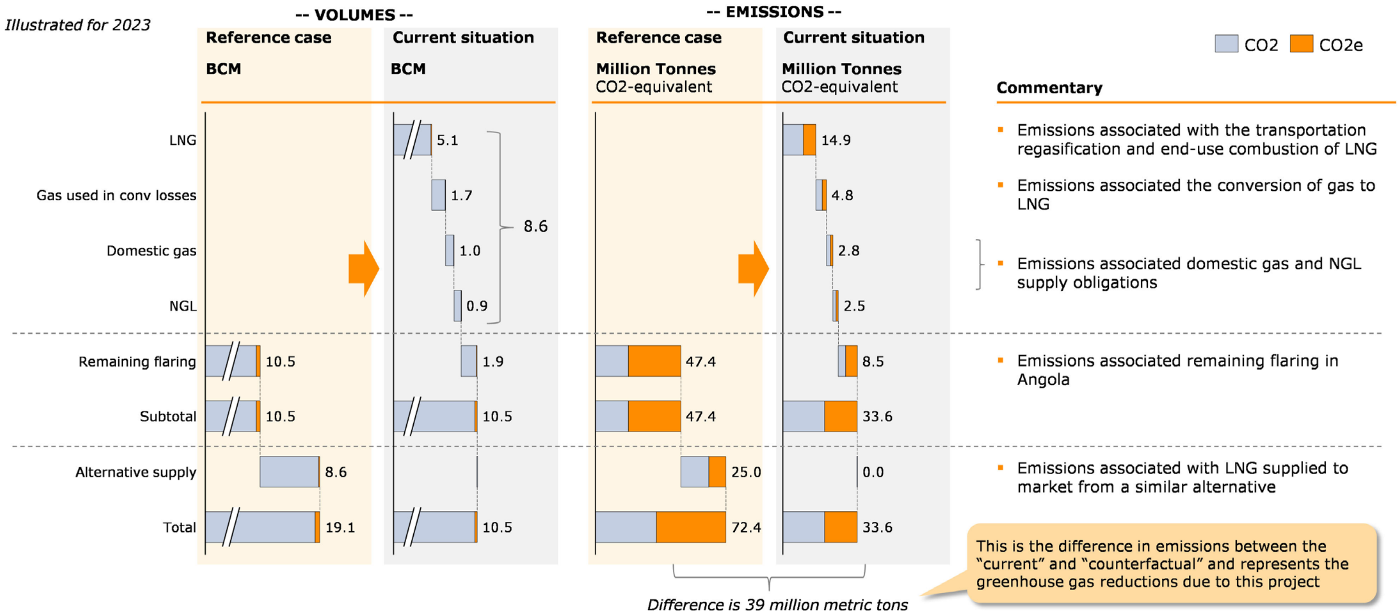
44 i.e. accounting for 2% net losses of gas—as methane—volumes between leaving Angola as LNG and reaching the end consumer as power.

45 The combustion efficiency of flares in an offshore real-world environment is not known, but the International Energy Agency estimates the global average to be 92%. Our assumption is somewhat conservative and may underestimate the emissions.

46 International Energy Agency. (2024). *Global methane tracker 2024*. https://www.iea.org/reports/global-methane-tracker-2024

- In the counterfactual (reference) case, we account for the same volume of gas (10.5 BCM), but assume that it is all flared at a combustion efficiency of 95%. We also consider in this counterfactual that if ALNG had not gone ahead, an alternative supply of gas would have been required with a similar emissions profile associated with the supply of LNG, domestic gas, and LPG and NGLs. We account for this in the "alternative supply" in Figure 4.

The impact of ALNG (the difference between the "current" and the "counterfactual" case) is a reduction in CO2-equivalent emissions of up to 39 million metric tons per year



Source: Capterio analysis.

Figure 4: Illustration of the CO_2-equivalent emissions from the gas system in Angola in 2023 under (a) the current situation (i.e., significant gas is used to produce LNG) and two alternative scenarios, and (b) no gas capture (but the same underlying oil production). See also Table 1. Note we use a global warming potential of methane of 82.5 times that of CO_2 (on a mass basis), over a 20-year period. See the discussion below and Figure 6, which provides more depth.

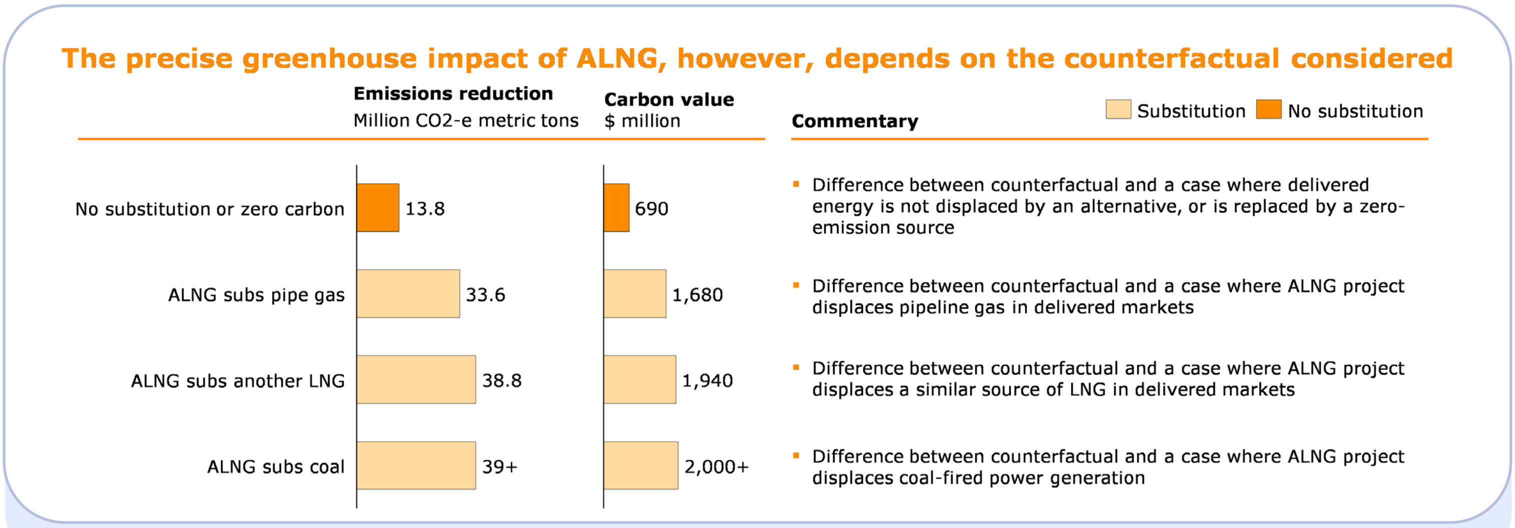
A like-for-like comparison of current situation for 2023 (emissions of 33.6 million metric tons CO_2-equivalent) with the counterfactual / reference case (emissions of 72.4 million metric tons CO_2-equivalent) results in a difference of 38.8 million metric tons of CO_2-equivalent per year.[47] This is our base case.

There are other scenarios to consider too. If the "alternative supply" was pipeline gas with a very low emissions intensity, it is conceivable that it could be up to 5 million CO_2-equivalent metric tons lower, meaning that the net impact is closer to 34 million metric tons CO_2-equivalent per year. Arguably, had the "alternative supply" of end-use energy been coal (or if this project had helped drive coal\to-gas-switching), then the impact of the emissions would have been greater. Alternatively, if we assume that ALNG did not substitute another source (or was substituted by a zero-carbon renewable source), then the comparative emissions would be 47.4 million CO_2-equivalent metric tons in the reference case versus 33.6 million, a reduction of 13.8 million CO_2-equivalent metric tons.

Figure 5 shows the range of emissions reduction we calculate (ranging from 13.8 to more than 38.8 million metrics tons per year) and an associated notional figure for the avoided carbon cost—if monetizable, e.g., through the avoidance of a domestic or international financial penalty (based on an assumed figure of $50 per CO_2-equivalent metric ton). This

47 In these calculations, we use the global warming potential multiplier of methane vs CO2 as 82.5 (on a mass basis, which is 30 times on a volume basis), consistent with the Intergovernmental Panel on Climate Change Sixth Assessment Report (https://www.ipcc.ch/assessment-report/ar6). This figure becomes 24 million metric tons of CO2-equivalent emissions if a 100-year global warming potential is used.

metric will become increasingly relevant to exporting nations as the European Union, for example, begins enforcing its "methane performance standard" on gas and oil suppliers to its markets. Future Carbon Border Adjustment Mechanisms may also present opportunities, particularly in markets like the EU, which may not only shrink in scale but also—amid the upcoming surge in global LNG supply—gain more diverse sourcing options.



Source: Capterio analysis.

Figure 5: Comparison of alternative views on the greenhouse gas reduction delivered by the ALNG project. The impact depends on what would have happened if ALNG had not happened—in particular, if another source of energy (low carbon, pipeline gas, LNG, or coal) would have been required to meet the market need. Additional emissions-reduction potential could be delivered if the remaining flaring volume (1.8 BCM in 2023) was captured.

There is another perspective too. Arguably, by monetizing flared gas, ALNG has also facilitated a lower carbon-intensity development of offshore oil fields. To put the scale of the emissions reduction into perspective, it is helpful to make a comparison with those from the oil production. We estimate that the emissions associated with the combustion by customers were 193 million metric tons of CO_2 in 2023. In effect, the emissions from associated gas (33.6 to 72.4 million CO_2-equivalent metric tons; see Table 1) might be reasonably added to generate a more complete greenhouse gas intensity of the oil.

Combining the oil and gas emissions, we estimate that the net emissions intensity of the underlying oil production has been decreased by the ALNG project (compared with a case in which the gas was not captured and was flared) by 14.5%,[48] from 661 to 565 kg of CO_2 per barrel of oil; see Table 1 (or 9.8% using a Global Warming Potential of 29.8, over a 100-year period).

	Current	Reference case	Difference
Oil emissions (MT CO2e)	193	193	0.0
Gas emissions (MT CO2e)	33.6	72.4	38.8
Total emissions (MT CO2e)	227	266	38.8
Oil emissions intensity (kgCO2e/bbl)	565	661	96.7
Oil emissions intensity (%)			14.6%

Table 1a: Breakdown of the annual emissions from the partial assessment of oil and gas supply chains under three scenarios. The ALNG flare capture project reduced the CO_2-equivalent emissions from oil and gas by about 15%, depending on the basis of the calculation. It is notable that there is further opportunity to reduce emissions by capturing the remaining flared gas and improving the process conversion efficiency (e.g., through electrification). See Figure 5. Note that the figures above are a partial assessment only and do not attempt to account for process emissions (such as scope 2 for production); this is beyond the scope of this paper. Rounding errors account for small differences. We use a 20-year Global Warming Potential of 82.5x for methane vs CO_2 on a mass basis.

48 This figure becomes 10% if a 100-year global warming potential is used.

	Current	Reference case	Difference
Oil emissions (MT CO2e)	193	193	0.0
Gas emissions (MT CO2e)	24.2	47.8	23.6
Total emissions (MT CO2e)	217	241	23.6
Oil emissions intensity (kgCO2e/bbl)	541	600	58.9
Oil emissions intensity (%)			9.8%

Table 1b: Breakdown of annual emissions as per Table 1a, but with a Global Warming Potential of 29.8, over a 100-year basis, shown as a sensitivity.

The discussion above highlights the various approaches to calculating the net emissions intensity of flare-capture projects. The calculation also is not only sensitive to the additionality or substitution potential of the delivered gas and oil, but also to the assumed Global Warming Potential (GWP) of methane vs CO_2.

While the overall emissions reductions highlighted above are positive under all scenarios, critics might argue that the gains made through emissions reduction were offset by higher scope three emissions from increased oil production. Put another way, if the ALNG project facilitated an increase in oil production by more than 10-15%, then emissions from increased oil production would be greater than the reduction in those from flaring (including associated methane emissions). As Figure 1 illustrates, Angola's oil production peaked in 2008 and was on plateau until 2017, so any increase in production due to the ALNG project was probably masked by declining production in other fields. To fully understand the net impact of LNG, we would need to analyze production at a field level, which is beyond the scope of this paper.

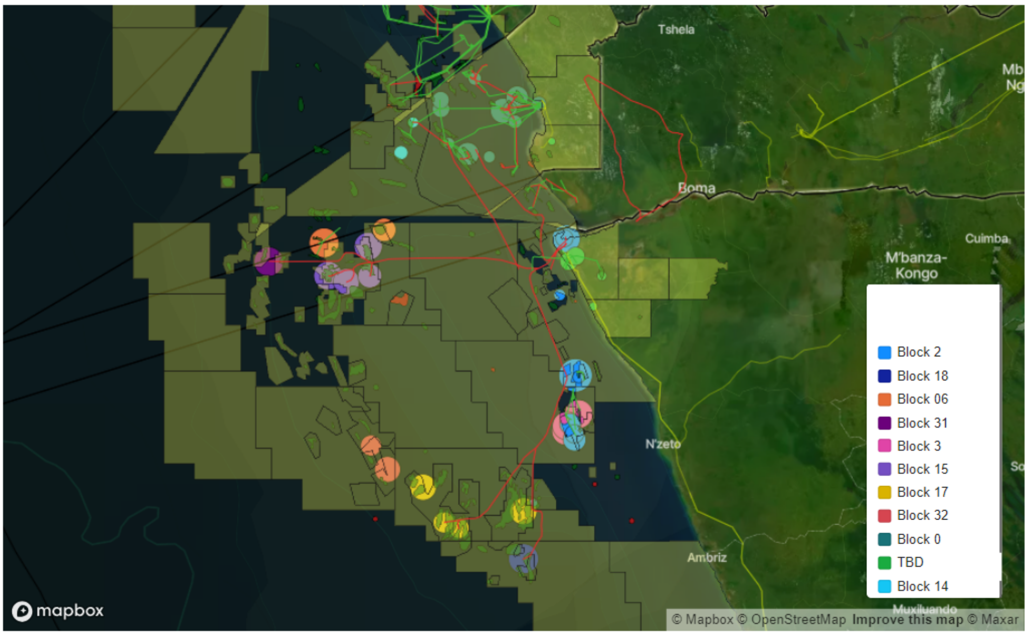
While we do not have strong views precisely how the emissions narrative should be articulated (especially since the total impact requires comparison of the actual versus a number of counterfactuals), the discussion above highlights the complexity of quantifying the direct and indirect impacts of such a project.

Looking forward: additional flare-reduction opportunities

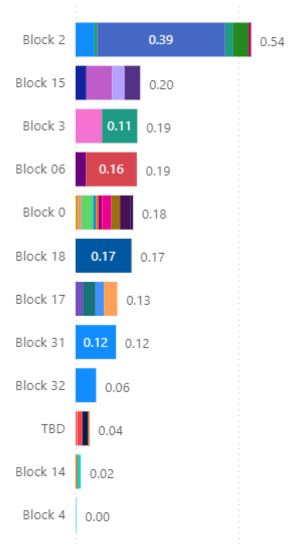
Despite ALNG's success in reducing emissions, significant gas flaring remains in Angola. In 2023, according to the World Bank, Angola flares 1.8 BCM, with 0.7 BCM from assets close to existing gas gathering systems in Block 2 and Block 3 (operated by Angolan oil companies ETU Energias and Sonangol), plus additional flaring in the blocks which supply gas to ALNG: 0, 14, 15, 17, 18, Figure 6).

Flaring today is dominated by block 2 (which does not supply ALNG)

Map of flaring today, color-coded by licensed block



Flaring by block
BCM, 2023



Source: Capterio FlareIntel.

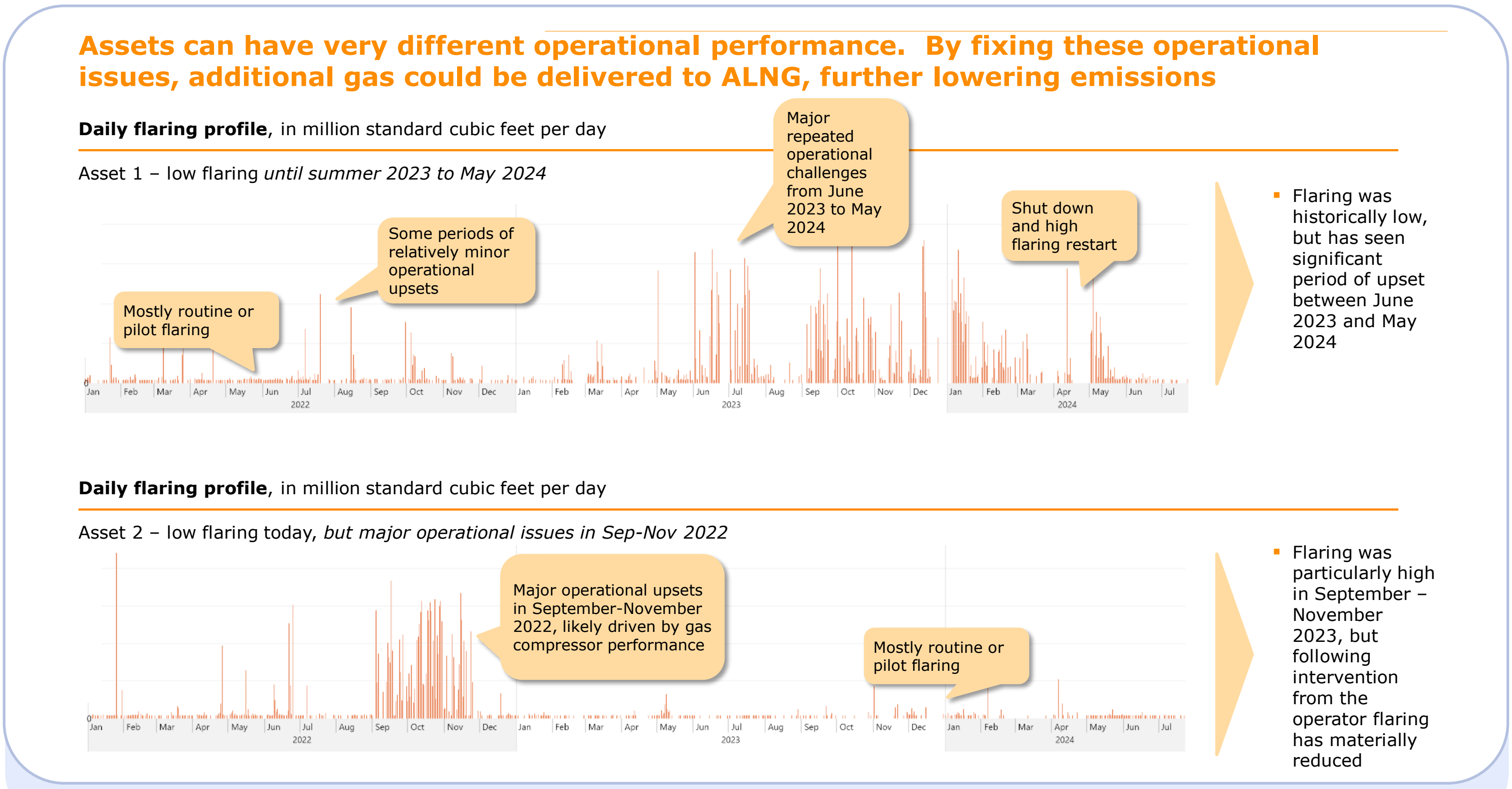
Figure 6: Overview of flaring and the main blocks, fields, pipelines, and powerlines from Capterio's Flare Intel Pro tool, incorporating annualized flaring data from the World Bank. Flaring is dominated by Block 2 at 0.5 BCM per year (led by Angolan operator, ETU Energias, formerly Somoil), followed by Block 15 (operated by ExxonMobil) and Blocks 3 and 6 (Sonangol). Block 15 (ExxonMobil) supplies ALNG.

Flaring performance also varies widely between operators, with flaring intensities (i.e., flaring per barrel of oil production) for oil majors ranging from 8.1 to 1.8 m^3 per barrel.[49] These differences may be attributable to the intrinsic elements of the oil itself, to the extent of linkage to flare-capture projects, such as LNG, and to underlying operational performance. Yet solving flaring arguably should be more in focus following Angola's decision, in January 2024, to exit from OPEC. Indeed, we expect that the exit is linked to a desire to increase future production and maximize revenue generation (and, therefore, its ability to meet loan repayments).[50]

To expand on the latter, using Capterio's high-frequency flare-tracking platform, FlareIntel, several fields appear to have recently had periods—sometimes for months—of high flaring (frequently up to 80 to 100 million scf per day), which could result from operational reliability challenges, like compressor failures), which improved maintenance regimes could potentially mitigate (Figure 7 upper).

49 Feldman, L., Patel, H, & Turitto, J. (2024). *Flaring Accountability: Global gas flaring by major oil and gas companies and their partners*. Clean Air Task Force. https://www.catf.us/resource/flaring-accountability/.

50 Mendes, C., & Burkhardt, P. (2024). Angola left OPEC to help sustain oil production above 1 million barrels a day. *Bloomberg*. https://www.bloomberg.com/news/articles/2024-01-03/angola-left-opec-to-help-sustain-oil-production-above-1-million-barrels-a-day.



Source: Capterio FlareIntel.

Figure 7 (upper): Examples of flaring from a selected deepwater asset in Angola that supplies gas to ALNG. Flaring materially increased in mid-2023 and for the following 12 months. Opportunities appear to exist to improve operational excellence, reduce emissions, and increase supplies of gas to the ALNG plant. Figure 7 (lower): Examples of flaring from another deepwater asset in Angola that supplies gas to ALNG. Flaring has reduced since the intervention in the winter of 2022, reducing the direct emissions of the operator and its partners while bringing additional gas to market. For context, flaring at rates of 20 to 100 million scf per day is equivalent to a revenue opportunity of $160,000 to $800,000 per day at current international prices.

Figure 7 (lower) illustrates the positive impact that can be achieved when operational issues, such as equipment failure, are addressed. This asset demonstrated low levels of flaring, with few operational upsets since November 2022. By improving equipment reliability, coupled with improved maintenance, additional volumes of gas could be recovered and sent to the ALNG plant. Operational excellence programs may be economically viable and pay for themselves by generating additional gas sales while reducing emissions, supporting the local economy, and improving local or international energy security. This financial incentive will be important for companies that have a financial stake in upstream assets and the LNG plant. Given that as recently as March 2023, ALNG canceled at least two tenders for LNG export cargoes[51] since it was forced to operate at lower-than-normal rates (70% capacity, according to government officials in late 2024[52]), this could be a significant value-creation opportunity.

Future plans

We are optimistic about several emerging opportunities to reduce and monetize flared gas in Angola, including:

- Developments in Block 15 (ExxonMobil) are expected to reduce flaring with the installation of a third FPSO equipped with advanced gas compressors and injection

51 Rashad, M. (2023) Angola LNG operating at reduced rates, tenders withdrawn – sources. *Reuters*. https://www.reuters.com/article/markets/angola-lng-operating-at-reduced-rates-tenders-withdrawn-sources-idUSL1N35T1DP.

52 Roelf, W. (2024). Angola LNG considers expansion as gas supplies ramp up. *Reuters*. https://www.reuters.com/article/markets/angola-lng-operating-at-reduced-rates-tenders-withdrawn-sources-idUSL1N35T1DP.

systems, enabling the reinjection of up to about 230 million scf per day of gas. This infrastructure will help capture and store more gas, reducing flaring.[53]

- Additional potential exists in shallow-water Block 3 (operated by Sonangol), which is immediately adjacent to the pipeline that transports gas from the deepwater fields to the LNG plant. This includes fields like Gazela and Buffalo, which are operated by Sonangol. The recent farm-in by Afentra,[54] a U.K. company, could provide renewed momentum for gas recovery and monetization in this block.
- Chevron's "Congo River Canyon Crossing (CRX) Pipeline", which connects fields in Angola and Congo, has today, up to 50% spare capacity. This additional capacity will accommodate gas from the Sanha Lean Gas Connection project (which in December 2024, eventually supplying 300 million scf per day)[55], but also may present a creative opportunity to capture and monetize flared gas from flaring in fields across the border in Congo. This latter option could represent an attractive way to leverage infrastructure and drive regional cooperation.

The newly established Azule Energy (a joint venture between bp and ENI[56]), is spearheading the New Gas Consortium. This consortium aims to develop the non-associated gas from shallow water fields Quiluma and Maboqueiro, conceived as make-up gas in the original project plans. This consortium took FID for this project in 2022 and is expected to supply up to 4 BCM of additional gas to ALNG starting in 2026, with a capital investment of around $2.2 billion.[57] Under the 2018 gas terms, the tax rate for non-associated gas is slightly improved on those for associated gas.[58]

Concluding Remarks: Insights and Learnings From ALNG

The ALNG project was a first-of-a-kind project that arguably has had significant success, despite the considerable technical and operational challenges and economic underperformance. The relative success can be attributed to several crucial factors and learnings:

- **Strong strategic leadership and proactive governance:** The leadership of Sonangol, coupled with Chevron's commitment and LNG expertise from bp, TotalEnergies, and ENI, played a pivotal role in the project's delivery. A key driver was Sonangol's strategic insistence on linking license extensions and the approval of new deepwater development plans to flaring-reduction commitments, which accelerated action on gas capture and infrastructure development. Additionally, strong political support from the Angolan government gave the project the stability it needed to thrive.
- **Value chain integration and alignment:** One of the project's significant innovations was alignment across the value chain. Partners in the upstream, gathering, LNG processing, transportation, and marketing phases were often the same entities. This fostered deep expertise and collaborative efficiency, but it also acted as a natural

53 Guyana Business Journal (December, 2025), ExxonMobil Expands Offshore Operations with Third FPSO Acquisition. https://guyanabusinessjournal.com/2024/12/exxonmobil-expands-offshore-operations-with-third-fpso-acquisition/.

54 Offshore staff. (2023). Afentra progressing offshore Angola block farm-ins. *Offshore*. https://www.offshore-mag.com/regional-reports/africa/article/14301355/afentra-progressing-offshore-angola-block-farm-ins.

55 Angola LNG. (n.d.). *Angola LNG – meeting the needs of Angola's energy demand.* https://www.angolalng.com/news/angola-lng-meeting-the-needs-of-angolas-energy-demand.

56 Azule Energy. (n.d.). *Azule Energy: An international energy company*. https://www.azule-energy.com.

57 Azule Energy. (2024, October 4). *Azule Energy and partners lay the foundation stone for the construction of the new gas consortium's facilities* [Press release]. https://www.azule-energy.com/wp-content/uploads/2024/02/Press-release-Azule-NGC-ENG.pdf.

58 International Trade Administration. (2024). Angola – country commercial guide. U.S. Department of Commerce. https://www.trade.gov/country-commercial-guides/angola-oil-and-gas.

hedge. This degree of vertical integration—rarely seen in gas projects—was critical in ensuring smooth operations and reducing friction between phases of production and distribution. That said, there were alignment challenges between the partners, especially around coordinating policies, systems, and work practices.

- **Innovative fiscal frameworks:** Driven by the strong value-chain alignment, Angola's government was able to offer a holistic and integrated fiscal framework. The government demonstrated flexibility and agility by leveraging oil revenue and the tax system to partially fund and cross-subsidize gas-capture efforts. The government offered cost-recovery mechanisms, capital allowances, and tax credits against upstream activities, which made the project financially attractive and ensured an attractive pre-FID IRR. These fiscal policies, supported by legislative adjustments, incentivized investment and reduced financial risks for stakeholders.
- **Flexibility in LNG sales strategy:** The project partners exhibited commercial and strategic flexibility by negotiating a positive outcome with respect to commercial contracts in the United States linked to the original long-term contracts. In doing so, ALNG shifted their target markets from the Gulf of Mexico to Europe and Asia. The initial spot sales contracts were later supplemented by term contracts, balancing short-term risk with long-term security. Sonangol's use of equity financing, rather than debt, added a layer of financial resilience to this strategy, especially since lenders are more reluctant to lend to projects without long-term sales agreements.
- **Reducing risk through gas-supply commitments:** The Angolan government's commitment to providing non-associated make-up gas from Blocks 1 and 2 served as an important contingency plan. Although not yet delivered, this facility was seen to be especially critical given that (a) the associated gas production (and therefore the supply of gas to ALNG) was dependent on the oil production, which had been governed in part by OPEC production quotas until recently, and: (b) the oil production comes from now-mature deepwater fields, where declining oil production could lead to unstable gas supply.
- **Importance of project design, execution and governance:** As with many large capital projects, project framing, up-front engineering and design, along with good execution, stakeholder management, and governance, are critical to realizing strong commercial performance. We do not think the technical and operational challenges that led to the commercial underperformance are related to ALNG being an associated gas capture project, so we do not support the views of those who say that LNG is per se an unsuitable solution for flared gas capture per se. We do, however, believe that the additional complexity and risk associated with such an associated gas project needs to be fully assessed.

In conclusion, Angola's LNG project stands as a pioneering and innovative example of monetizing flared gas. With the impending surge of new LNG supply projects soon to come on stream as well as the imperative need to avoid lock-in more capital in fossil fuel infrastructure, we consider it unlikely that LNG—at least at this scale—will be a common solution (outside of the US shale basins, where they exist already) in the coming years. But since few other projects can offer such compelling benefits for both the environment and the economy, these are important lessons for other flare-capture projects internationally.

To find out more, or share your feedback, please email the authors at: ptoled@law.columbia.edu or mark.davis@capterio.com.

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