Minimising Greenhouse Gas Emissions in the Petroleum Sector: The Opportunity for Emerging Producers

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AFRICAN DEVELOPMENT BANK GROUP

The Commonwealth

NEW PRODUCERS GROUP
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Africa Natural Resources Management & Investment Centre

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Executive summary

Limiting global warming requires significant and urgent reductions of greenhouse gas emissions by the petroleum sector, in line with the Paris Agreement. The majority of the sector's emissions arise downstream from the end use of petroleum products by thousands of industries, hundreds of countries and billions of individuals. However, the balance relates to the upstream production of oil and gas which is concentrated in producing countries that could act decisively on reductions and make a significant impact. Emission intensity varies widely between producers, providing a huge opportunity for using existing technologies and best practices to improve standards and reduce emissions. In a carbon-constrained world, oil and gas producers who can demonstrate that their projects are delivered with the lowest emissions will become more competitive as the cost of carbon increasingly becomes reflected in the price of using oil and gas.

Unlike established producers with sectors configured for a less carbon-constrained era, new producers have an opportunity to design their laws, regulations and projects to reduce emissions. This will be both less expensive and more efficient than trying to change what is already in place. Thus new producers can be better positioned to protect their projects from becoming stranded as climate change restrictions tighten, as is widely expected. Many international bodies, banks, investors and operators are already becoming more cautious about financing the petroleum sector. Minimising emissions as much as possible is no longer a "nice to have" feature but the cost of being in business and must therefore be a priority for governments wanting to develop their petroleum sector for the benefit of their populations.

This paper discusses how governments can approach this challenge and sets out the most important areas of focus: understanding and estimating greenhouse gas (GHG) emissions, targeting and achieving near-zero routine flaring, venting and leakage (including outlining possible uses for associated gas) and dealing with the residual and hard-to-abate emissions. Further resources available to governments are also signposted.

Political will is vital as the foundation for minimising GHG emissions from a country's petroleum sector, and may be embodied in a number of international (e.g. nationally determined contributions) and domestic pledges. However, the gap between intention and effective implementation can be significant. Clear regulation is needed, as is clarity of responsibility, giving regulatory authorities sufficient power and trained resource to implement controls, and managing the complex relationship with operators which are already under pressure from their shareholders, but still needing robust oversight. Coordination and communication are critical to successful implementation, and transparency will help build trust with civil society groups and other stakeholders.

Minimising GHG emissions should be at the centre of all decisions made about the sector, from initial project design through operating practices to a fully-funded decommissioning plan. Governments have various levers at their disposal, the most important of which is the approval or rejection of field development plans. Governments also have to prioritise, and implementing near-zero routine flaring and venting practices while establishing robust leak detection and repair processes will reduce emissions significantly, while progress is made elsewhere. Effective monitoring is important: technology including near real time information and free satellite data together with punitive fines can be highly effective. Decisions about the potential uses of associated gas are often complicated. The right choice (reinjection, liquified natural gas (LNG), feedstock, use in the domestic or regional market) will depend on the specific country circumstances. The use of renewables, either directly in the petroleum sector or as a lever to develop them more widely in a country's power sector, has potential, but is highly dependent on a country's particular circumstances. Governments should seek to minimise GHG emissions in their petroleum sector as much as possible and only then use offsetting, and possibly carbon capture, utilisation and sequestration (CCUS), to deal with any residual emissions.

01

Introduction

Responsibility for petroleum-related emissions is shared between producers and consumers. While emissions from fuels that are burnt by users and consumers represent 75-80% of the lifecycle emissions, tackling the problem of reducing them is complex because billions of consumers use them. In contrast, each producer controls a meaningful share of emissions. This represents a singular opportunity in the battle to tackle climate change, where a relatively small number of actors can take cost-effective steps to significantly reduce harmful greenhouse gas emissions (GHGs). The onus is therefore on producers to minimise scope 1 (direct emissions from owned or controlled sources) and scope 2 emissions (indirect emissions from the generation of electricity, steam, and of other inputs for heating, cooling, and other oil and gas processing).

The emissions burden from emerging producers today remains small - estimated at only 1.7% of global GHGs for the 27 member countries of the New Producers Group,[1] but the absolute amount of emissions will inevitably grow as their new reserves are produced. This paper identifies the key levers available to emerging producers, such as Ghana, Uganda, Mozambique, Mauritania and Suriname to minimise scope 1 and scope 2 emissions, ensuring that new production is at the lowest possible emissions level and also offset to prevent an increase in national emissions. Minimising GHG emissions from the petroleum industry is no longer a voluntary measure, it is the necessary cost of doing business and the condition of entry for new producers.

External pressure is already being brought to bear on the industry to cut emissions. Oil and gas companies are under mounting pressure from many shareholders and from civil society to make commitments and take action supporting climate goals. Policy and regulatory measures in consuming countries can tax both fossil fuel imports and consumption and offer incentives

[1] Research by Dr Valérie Marcel, Deborah Gordon, Naadira Ogeer, Dr Ekpen Omonbude (forthcoming). The New Producers Group is a peer-to-peer community of government officials from 27 countries at the exploration, development and early production stages.

to renewables.[2] International finance bodies, banks and insurance companies are already limiting their exposure to the oil and gas sector, increasing the cost of capital and restricting its availability. Investors and capital markets are anticipating the introduction of new policy and regulatory measures in consuming countries that will require the cost of carbon to be reflected in economic transactions. Investors already judge oil and gas projects by where they sit compared with other projects on a cost curve, believing that a project lower on the cost curve will be more resilient against stranding (see Glossary). In the same way, projects can and will be compared in terms of their GHG emissions intensity. Analysts are already constructing emissions curves for the industry, and companies and investors will use them to evaluate how robust projects will be if emissions restrictions or carbon taxes are introduced.[3] Successful projects will have to be not only at the low end of the cost curve, but able to demonstrate that they can produce hydrocarbons with the lowest emissions.

Pressures will also emerge within producer countries. Risky bets with public funds may result in stranded assets, with potential political consequences.[4] Local climate impacts will raise domestic concerns, and the public acceptability of petroleum production may be eroded and reversed. Most emerging oil and gas producers have committed to net zero emissions by 2050, but in a context of high vulnerability to climate change, slow progress in implementation can undercut public support for new oil and gas projects.

New approaches are needed to attract investment in projects addressing national energy gaps, while at the same time minimising both the associated emissions and stranding risks. New producers have an advantage over legacy producers because they can design their petroleum systems as a 'new build' with the lowest possible GHG emissions. They can set design specifications and regulatory frameworks to reduce and monitor emissions, to integrate renewable energy into projects, as well as to leverage these inputs to benefit the national power generation system. Governments can draw on these new criteria to avoid investing in high GHG-intensity projects that will lose their value in a carbon-constrained world and will harm the natural capital of the country. Introducing a framework that produces project designs fit for a carbon constrained world can be far easier for new producers than for countries with long-established petroleum sectors where legacy systems and organisational cultures make it difficult to retrofit systems, build differently and change regulations and operating practices.

The immaturity of the sector carries some disadvantages however, including limited experience, capacity and infrastructure. Durable technical assistance programmes would provide critical capacity-building, but OECD development agencies and most multilateral development banks have adopted new guidelines that prevent them from supporting new petroleum development

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[2] Although currently European governments are subsidising gas, rather than taxing it, as the continent is grappling with an energy crisis in the aftermath of the Russian invasion of Ukraine. See Giovanni Sgaravatti et al. (2022), 'National policies to shield consumers from rising energy prices', Bruegel, 21 September;
https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices. European governments are also providing incentives for renewables development to meet energy needs.

[3] For examples see: International Energy Agency, World Energy Outlook 2018, Chapter 11, "Innovation and the Environmental Performance of the Oil and Gas Supply," Figures 11.6 and 11.7, https://iea.blob.core.windows.net/assets/77ecf96c-5f4b-4d0d-9d93-d81b938217cb/World_Energy_Outlook_2018.pdf and RMI, Oil Climate Index plus Gas, 2022, https://ociplus.rmi.org/supply-chain

[4] David Manley, Patrick Heller (2021). 'Risky Bet: National Oil Companies in the Transition', NRGI, https://resourcegovernance.org/analysis-tools/publications/risky-bet-national-oil-companies-energy-transition

beyond their borders.[5] Unlike established producers, emerging producers cannot use the revenues and savings from oil and gas sales to fund new processing, gathering, transport, transmission and power infrastructure. Without the support of finance from multilateral development banks, projects will depend on private capital. Governments will have to accept that, in order to develop their oil and gas resources, the initial cost of comprehensively controlling emissions will have to be cost-recoverable.

This paper will discuss the resources required to create a framework that supports low emission projects in an imperfect context, including how to manage their timing and resource allocation. As we will see, the introduction of robust operational practices such as near-zero flaring and robust leak detection and repair (LDAR) can reduce GHG emissions significantly, even as plans for better measurement and monitoring are developed and can be implemented far faster than building a local market for associated gas or leveraging renewables into the power system of a country.

A broader challenge lies in moving from emission pledges to real implementation. It is vital that countries move beyond abstract goals and devote political capital to forging a new path. This entails combining international climate commitments, expressed as nationally determined contributions (NDCs) and net zero goals with national planning and operational petroleum sector decisions. A clear policy that aligns these three levels, sanctioned at the highest level, will be necessary to guide business decisions, implement regulations and enforce sanctions where necessary. The future role of the sector within the wider economy should be clarified in a national decarbonisation plan which would support government coordination and communication.

Once this foundation of enabling political and public management is established, new producers should focus on the levers within their control to minimise scope 1 and scope 2 emissions. The paper examines four proposed focus areas for emerging producers which can reduce emissions. Firstly, new producers need to understand petroleum sector emissions, as this knowledge is the foundation for any efforts to minimise them. Secondly, they should regulate and design their sector to prevent routine flaring and methane leakage. The paper will examine how the regulatory framework, diligent monitoring, forward-looking project approvals, and managing how to deal with associated gas can play an important role in preventing routine flaring, venting (the direct release of natural gas into the atmosphere) and leakage. Thirdly, they can introduce renewables into the project design. Fourthly, they will need to tackle the residual, hard-to-abate emissions.

[5] The African Development Bank stands alone among multilateral development banks in its willingness to finance gas projects, with its president, Akinwumi Adesina, stating that "gas is fundamental to Africa's energy system" (Bloomberg, 4 November 2021). However, the scale of its interventions is restricted without co-financiers to match funds.

02

Understanding and estimating greenhouse gas emissions

This paper draws on insight gained during a New Producers Group training series on emissions.[6] Government officials from a range of agencies in eight participating countries identified the following important gaps in their understanding of emissions expected from their petroleum sector:

-01-

A need for clarity about which institution is charged with collecting GHG-relevant data and the roles of the various actors in the sector. Participating agencies expressed concern about limited information sharing and coordination across government.

-02-

A need for capacity building and training for data management, monitoring and verification (including training on the use of equipment)

-03-

Limited publicly available data on emissions - at both country and asset level. Operators do not generally share how they calculate their emissions data, using the argument that it is commercially sensitive.

-04-

Many countries do not yet have explicit emissions reporting requirements, although several are developing them.

Understanding oil and gas supply chains and estimating GHGs from industry operations is the starting point to minimise climate impacts. It is difficult to manage complex problems like oil and gas climate impacts without quantitative emissions estimates. Conversely, the more you know about what is driving emissions and how a project's emissions compare with those of similar projects, the better climate-related decision-making can be. Emissions intensities vary widely depending on the type of resource and operations employed and vary by a factor of ten across production, processing and shipping from the highest- to the lowest-emitting oil and gas resource.

[6] *Minimising GHG Emissions from the Petroleum Sector, virtual training, New Producers Group June 27-July 8 2022, https://www.newproducersgroup.online/event/virtual-training-minimising-greenhouse-gas-emissions-from-the-petroleum-sector/ Participating countries included Mozambique, Suriname, Guyana, Uganda, Ghana, Namibia, Mauritania, and Brazil.*

Operators have often developed their own methodologies, tending to use simple emissions factors to estimate emissions from their projects. Standard emissions factors[7] tend to be outdated, oversimplified, and do not reflect the significant differences between projects arising from the type of resource, operating practices, life-cycle emissions intensities, or absolute GHGs emitted. Moreover, it is often wrongly assumed that emissions remain constant over the life of a project. In fact, emissions tend to rise as assets age and enhanced recovery techniques are needed to maintain production and throughput volumes, although this can, to some extent, be addressed by requiring comprehensive facilities management and remediation programmes throughout a project's life.

A standardised, open-source approach, like the Oil Climate Index plus Gas (OCI+) model,[8] offers a more accurate and transparent GHG impact assessment. It is important for governments to understand project-level emissions to monitor their emissions data effectively throughout the project's life. Just as there are cost curves for the industry, there are GHG intensity curves available using standardised, project level models.[9] Such data is also necessary where border carbon tax adjustments exist (as in the EU) or methane fees are charged (as in the US).

In estimating emissions, a project's characteristics include some elements that are controllable and some that are not. The following underlying field characteristics are largely uncontrollable. While this data may be known before the project is built out, it is often not made publicly available in a comprehensive way. As conditions change over time, new data can be used to improve the emissions estimates. Examples of these factors include:

i. The reservoir type (e.g. oil, gas, or condensate);
ii. The location of production (e.g. onshore, offshore, deepwater, fragile ecosystems such as rainforests, permafrost, peatlands);
iii. The reservoir's physical characteristics (e.g. depth, pressure, temperature, reservoir complexity,);
iv. The reservoir's chemical make-up (e.g. oil gravity, gas composition, gas-to-liquids ratio, entrained contaminants like carbon dioxide, nitrogen, hydrogen sulphide, water);
v. Reservoir changes over the course of a project's lifetime.

There are also numerous project design and operator decisions that are at least partially controllable and can be detailed to improve the accuracy of emissions estimates both at the outset and over time, including:

i. The production techniques used (e.g. fracking, steaming, enhanced recovery methods, carbon capture);
ii. Production volumes of oil, gas, condensates (depending on techniques used);
iii. Gas flaring management (e.g. volumes, equipment efficiency, preventing unlit flares);

[7] *Standard emission factors used by industry include the following: US Environmental Protection Agency, "Emission Factors for Greenhouse Gas Inventories," April 1, 2022, https://www.epa.gov/system/files/documents/2022-04/ghg_emission_factors_hub.pdf; Intergovernmental Panel on Climate Change, "Emission Factor Database," https://www.ipcc-nggip.iges.or.jp/EFDB/main.php*
[8] *https://ociplus.rmi.org/*
[9] *The International Energy Agency, for instance, has used the OCI+ model to this end. https://iea.blob.core.windows.net/assets/77ecf96c-5f4b-4d0d-9d93-d81b938217cb/World_Energy_Outlook_2018.pdf*

iv. Gas venting (e.g. methane and CO2 from all equipment and processes);
v. Initial process design and operating decisions (for example the use of gas reinjection or enhanced oil recovery methods). These are crucial because retrofitting is far more expensive and less effective;
vi. Fuel input decisions (e.g. fossil fuels or renewables for heat, steam, and electricity);
vii. Robust leak detection and repair programmes (LDAR) together with the installation of appropriate meters to monitor leaks.

These controllable decisions can be framed by governments in their regulatory requirements, affecting whether venting, flaring, energy inputs, data reporting, requirements, and other critical decisions minimise emissions at a national level. Using the field development plan approval process to establish permit conditions and operating requirements can signal the government's intentions, promote best practices and avoid expensive future retrofits. The next section will detail how governments can use regulatory guidelines and project approvals to impact these controllable decisions.

Fiscal terms and financial incentives are also under government control and can be used to send strong signals about the types of projects that are permitted to go ahead. This may take the form of incentives for minimising gas flaring, for the provision of gas to the local market, disincentives for heavy oil projects and financial penalties for flaring practices.

Recommendations for new producer governments

- Know your hydrocarbon resource characteristics, the production operations employed, and how project-specific emissions are being estimated. A number of models are available to help with this.[10]
- Understand the types, collection frequency, and assessment methodologies used by your operators to collect their own data.
- Clarify the transparency requirements for production and emissions data.
- Obtain data at an individual project level and make it public, rather than use broad assumptions or aggregated data that can introduce errors or obscure resource details. Disaggregated data will bring greater external scrutiny to bear on oil companies for their performance in emissions control.
- Frame the controllable aspects of emissions in your regulatory system (e.g. accepted emissions intensity, the proportion of fossil versus renewable energy inputs, requiring near-zero routine flaring, venting and data requirements).
- Use the field development plan approval process to ensure that projects include an emissions management plan and that emissions are continuously monitored (c.f. Section 2 C).

[10] To estimate and track oil and gas GHGs, see: RMI OCI+ model https://ociplus.rmi.org (Note: RMI's OCI+ is open-source and free). Wood Mackenzie and other consultants have models on a fee-for-service basis.

03

Zero Routine Flaring, Venting, and Methane Leakage

3.1. What is at stake

The petroleum industry's production, processing and transport of oil and gas contribute significantly to global greenhouse gas emissions, reaching an estimated 15-20% of worldwide CO2-equivalent emissions in 2020.[11] Oil production is responsible for around 40% of methane emissions, with leaks across the natural gas value chain accounting for the remaining 60%.[12] Significant scope 2 emissions from gas systems also arise from processing, transmission and distribution, natural gas liquefaction, and regasification activities. In order to achieve the Paris Accord target to restrict warming to under 1.5 degrees Celsius, global methane emissions must be reduced by 45% by 2030. Oil and gas operations are the second largest contributor to global methane emissions, after agriculture. The International Energy Agency (IEA) has set a target of 75% reduction in global methane emissions from fossil fuel operations by 2030.

The good news is that implementing tried and tested policies would halve methane emissions, and existing technology can reduce methane emissions by 70%. At a gas price equivalent to the average of the last five years, 40% of methane emissions could be abated at no net cost.[13] If all waste gas (methane) could be captured and sold, the revenues would be three times the cost of capture. However, there are reasons why it may not be possible to operate 100% leak-free and prevent all fugitive emissions. In this case, operators can install microturbines onsite to generate electricity from unwanted (otherwise flared and vented) gas.

Within the oil and gas value chain, venting (the direct release of natural gas into the atmosphere) accounts for an estimated average of 60% of methane emissions; fugitive emissions (leaks

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[11] IEA estimates oil and gas supply-side emissions at 5.4 Gt CO2e in 2020 and global energy related CO2 at 30 Gt. See: IEA (2022), 'Oil and Natural Gas Supply', IEA, https://www.iea.org/reports/oil-and-natural-gas-supply. Note that this share resides at the upper bound (20%) when CO2e is adjusted assuming a 20-year global warming potential from the Intergovernmental Panel on Climate Change, AR6 of 82.5x for methane.
[12] IEA (2022), https://www.iea.org/fuels-and-technologies/oil
[13] IEA (2022), 'Methane Emissions from Oil and Gas Operations', September: https://www.iea.org/reports/methane-emissions-from-oil-and-gas-operations

that can go undetected without regular inspection) for 20%; flaring (95% of which could be avoided) for 10%; and the remainder is reportedly picked up by satellites and comes from other sources.[14] These shares can vary widely by asset, operator, and country. Methane satellites are poised to gather much greater climate intelligence in future to pinpoint methane emissions from venting, fugitives, and flaring.

Despite the many advantages of reducing methane, which include reducing air pollution and associated health problems, mitigating global warming, preventing fires and explosions, and maximising gas sales, it has rarely been a high priority. Common barriers to reducing methane emissions include poor awareness of the benefits, lack of regulatory requirements and enforcement, the absence of public and private resources, the need for investment or technical advanced planning, data and technical expertise, incentives, coordination, and an enabling framework. Finding an economic alternative use for waste gas is often a barrier. The challenge is that flaring (from both inefficient or unlit flares) and venting are the simplest and lowest cost solutions (depending on the level of fines) to the problem of associated gas, as will be discussed below.

Several global pledges have been made by countries to reduce methane emissions. For example, the Global Gas Flaring Reduction Partnership (GGFR) is a public-private initiative that aims to increase the use of natural gas associated with oil production by helping to remove the technical and regulatory barriers to flaring reduction. The World Bank and the United Nations launched the Zero Routine Flaring by 2030 initiative, which has 102 endorsers. The Global Methane Pledge to reduce methane emissions by 30% by 2030 has been signed by 120 nations. The Commonwealth Methane Action Group aims to support governments by strengthening climate capacities, supporting the introduction of national regulations to embed voluntary practices, highlighting the opportunities to get commitments and data from operators (using field development plan approval) and by developing pilot projects and knowledge exchanges. The Oil and Gas Climate Initiative consists of 12 private and national oil companies committing to near-zero methane and other measures to accelerate the industry response to climate change.[15]

3.2 Establishing a petroleum sector without routine flaring, venting, and leakage

Emerging oil and gas producers can make pledges of their own to establish their nascent petroleum sector without routine flaring, venting or methane leakage from its inception. They have the considerable advantage of being able to design in (or require operators to immediately incorporate) the most effective technologies and operating practices to avoid routine flaring, venting and methane leakage from the first day of production. The following sections detail four levers that new petroleum producers can use to establish a sector avoiding these damaging practices : a) regulation; b) monitoring; c) project design; and, d) planning how to divert and use any associated gas. It will also explore how to overcome common barriers to implementation.

[14] *IEA, Methane Tracker, Updated September 1, 2022, https://www.iea.org/data-and-statistics/data-tools/methane-tracker-data-explorer*
[15] *See Appendix: further resources.*

A. Strong regulatory guidance (guidelines, rules, laws, regulations)

Political will (often following high-profile climate emergencies) gives impetus to developing a comprehensive and robust set of GHG rules and regulations that serve to set standards and establish enforcement. Policy goals are also set out through international pledges and in a country's nationally determined contributions (NDCs).

To achieve standards with the lowest possible GHG impacts it is necessary to put emissions at the centre of considering each step of every project from licensing, through project approval, ongoing monitoring and ultimately decommissioning. A clearly structured regulatory regime should clarify how to govern emissions at each step.

Regulation can be prescriptive, for example including requirements for the use of best available technology and specified standards of leak detection and repair (LDAR). It can be performance-based, setting emissions and methane intensity standards. It can be economics-based, using methane emissions taxes and taxes on venting and flaring to incentivise operators. It will not be possible to eliminate venting, flaring and methane emissions entirely, but clarity on taxes and fees will allow operators to understand the cost of any fugitive emissions. Regulation can also be information-based, by requiring the provision of impact assessments and specifying what emissions data should be disclosed (and in turn made public).

Carbon price levels (real or shadow)[16] make a great difference to the commercial viability of investments aimed at reducing GHG emissions. Many operators already apply an internally determined carbon price to test the resilience of projects. Listed companies in particular often have a near or net zero plan which they intend to pursue irrespective of the local emissions requirements. An oil company's commitment to reducing the emissions intensity of their operated and non-operated assets can create an alignment of purpose with the government's emissions reform plans. It does not, however, absolve governments from the duty of oversight.

Gas that has been produced to standards generating the lowest emissions can be certified, and this can have value in the marketplace. It can also support exports to countries with border carbon tax adjustments where countries charge a fee based on the carbon emissions of imported goods, for example the EU.[17] Certifying agencies include MiQ, which is an independent, not-for-profit foundation existing to certify gas,[18] and governments can require such independent certification, which can be externally audited to support exports to a market that has specific standards. It is worth monitoring how the market develops, as this could become a differentiator for producers, potentially adding a price premium or privileged access to buyers who value that standard.

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[16] *See glossary.*

[17] *The Commission presented its proposal for a regulation establishing a Carbon Border Adjustment Mechanism on 14 July 2021. It aims to address the risk of carbon leakage caused by asymmetrical climate policies of non-EU countries (where policies applied to fight climate change are less ambitious than those of the EU).*

[18] *htpps://miq.org*

Recommendations for new producers[19]

- Access resources such as the IEA Regulatory Roadmap and guidance from other resources (listed in the Appendix) to define strong regulatory objectives and select the appropriate policy design.
- Ensure that the laws and regulations already governing the petroleum sector are aligned with new, best practice flaring and emissions regulations. Seek out best practice in other countries to inform your design of policies and regulations.
- Decide where the design and enforcement of regulations should sit (this is often the Environmental Protection Agency, although it can be the oil and gas licencing authority) and ensure that this responsibility is well coordinated with the petroleum ministry to avoid regulatory gaps.
- Clarify how sanctions for breaches are set and imposed, avoiding reliance on ministerial discretion.
- Allow the regulatory authority the necessary legal powers to enable it to enforce the regulations and provide appropriate resources to monitor and implement compliance.
- Invest in people and training to build regulatory capacity.
- Engage your stakeholders to increase awareness, understanding and trust in the process.
- Review and refine your policy periodically as key factors such as technology to control emissions and to commercialise gas and gas markets, and international requirements and treaties can change dramatically in a short period of time.

B. Monitoring, learning, and ensuring good operational practice

Once a petroleum project is in progress, routine monitoring becomes crucial. Technology now exists that can provide near real time emissions data, available within minutes from fence line monitors, and within a couple of months from satellites. Oil operators have introduced daily reporting of operational data (such as production volumes, flared gas, and other activities), for example in Guyana, where the government made the data available to the public.[20] Although the investments are cost-recoverable, they also provide value by giving governments and stakeholders timely access to data. Additional monitoring is also increasingly available from an array of GHG satellites (methane and CO2) that repeatedly survey operations from space and identify both persistent and intermittent emitters.[21]

Record keeping is crucial to this process, to enable reporting on both greenhouse gas emissions and flaring and venting (especially important where there are fines or taxes to be applied). Third party verification is a vital cross-check to ensure accuracy and to underpin the application of sanctions. For all of these steps, training is crucial and well-coordinated policies can ensure that

[19] Adapted from the IEA Regulatory Roadmap (also available in French, Spanish, Chinese, Arabic and Russian), which offers 10 steps governments can take to choose a regulatory approach and implement a set of effective methane policies that match a particular situation: https://www.iea.org/reports/driving-down-methane-leaks-from-the-oil-and-gas-industry/regulatory-roadmap

[20] Petroleum Management Programme, Ministry of Natural Resources; https://petroleum.gov.gy/data-visualization?tid=All&tid_1=All

[21] Data is publicly available from Skytruth and the World Bank's Global Gas Flaring Tracker. See Further Resources in Appendix.

loans and grants are available (from domestic funds and from donors), and that research and development is funded to continually improve systems.

Operators, while they now generally face pressure from their shareholders and other stakeholders to minimise emissions, must be carefully regulated and monitored. They should be guided by robust standards on maintaining up-to-date equipment and robust leak detection and repair processes, which can make a significant contribution to reducing emissions even in the absence of comprehensive monitoring. Governments could require the implementation of a number of technological solutions, proven in a number of different contexts,[22] including:

i. Early replacement of devices;
ii. Replacement of pumps;
iii. Replacement of compressor seals or rods;
iv. Instrument air systems;
v. New electric motors;
vi. Vapour recovery units;
vii. Blowdown capture;
viii. Installation of flares;
ix. Installation of plungers;
x. Leak detection and repair (LDAR) systems, both upstream and downstream.

It is critical to proceed with both common-sense rules for LDAR to minimise flaring and process venting while also working toward better measurement of emissions to track and verify progress, and to ensure that meaningful incentives are in effect.

Recommendations for new producers

- Define monitoring requirements clearly in regulation.
- Allocate responsibility for monitoring and invest in the capacity of the responsible agency.
- Require the most up-to-date monitoring technology and systems coupled with requirements to update them as technology improves - to a best available technology standard.
- Ensure that sanctions are appropriate, clear, and uniformly applied.
- Invest in the processes and the people to implement the monitoring regime. This is where many countries have failed, despite good intentions.
- Recognise that the more transparent and robust the monitoring regime is, the more likely projects are to meet international standards and the less likely they are to become stranded or have to be closed down in the future.
- Require the implementation of the IEA methane toolkit recommendations to ensure that production processes minimise emissions as much as possible.

[22] *https://www.iea.org/reports/driving-down-methane-leaks-from-the-oil-and-gas-industry/regulatory-toolkit; https://iea.blob.core.windows.net/assets/b5f6bb13-76ce-48ea-8fdb-3d4f8b58c838/GlobalMethaneTracker_documentation.pdf*

C. Project approvals: focus on minimising GHG emissions as part of the field development plan process

As discussed earlier, evidence shows there is a wide variation in GHG emissions intensity amongst similar projects. It is widely recognised that by using known technology and best practices to address flaring, venting and fugitive emissions, new projects can be delivered at the lowest emission intensity levels. As we saw, new producers have the advantage of being able to design projects to near-zero methane, flaring and venting when compared to mature producers with legacy assets and infrastructure.

One of the most powerful points of leverage that governments can use is to include a requirement for a GHG management plan in the approval process for the field development plan (FDP), ideally specified within the governing law or regulation. Recognising that legislative change may be a lengthy process, regulators can also rely on their national FDP submission guidelines. Countries generally have legal requirements to minimise environmental impacts and, as GHG emissions are pollutants, this provides legal anchoring for the inclusion of GHG management plans in operational guidelines. These plans could outline policy positions, require estimates of life cycle emission and emissions benchmarks against the best-in-class projects, and embed current known mitigation actions and best practice in the design and operating requirements. As with other components of a FDP, the GHG management plan should allow for continuous improvement and the requirement for them to be updated as technology improves.

Fast track developments are becoming the norm for oil projects in new producing countries, and this introduces a significant risk that projects could become higher emitters despite the existence of strong policies or laws. Compared with mature producers, there is much less information on the subsurface and little infrastructure. This means there is greater uncertainty about key aspects of projects, and this increases the risk of operational changes to the extent that core facility design parameters can be breached. For example, gas-oil ratios may be higher than planned, which could mean that more gas is produced than can be handled, resulting in flaring or venting. As part of its FDP review, the government should ensure that the operator's choices at the design stage adequately address these uncertainties and design mitigation strategies to avoid unacceptable emissions resulting.

An insistence on minimising GHG emissions as a key consideration in the FDP, requiring the operator to demonstrate that the project has been designed to meet best-in-class standards, and that measures will be put in place to manage emissions effectively will have implications for costs. However, while the upfront development costs may be higher than designing to a lower standard, such upfront costs will be much lower than trying to retrofit projects to comply with tighter regulations in the future. Enlightened politicians and regulators could position their country to be at the forefront of this shift.

Governments should ensure that projects operated by national oil companies (NOCs) also meet similar standards to ensure their long-term viability. Access to finance and export markets will be increasingly dependent on emission intensity, so NOCs should design and operate low emissions projects or face the serious risks of being competitively disadvantaged or seeing their assets stranded. Where NOCs are minority equity partners, they should seek to influence operator decisions positively through joint development committee meetings, as a best-in-class publicly listed oil company seeking to meet its net zero goals would do.

Political will, and clarity of regulation - with suitable incentives and sanctions - can help to align the interests of governments and operators. There will nevertheless always be a need for governments to invest in their capacity to assess such plans (e.g. in the field development plan approval process) and to monitor and audit information coming from operators (including NOCs). The regulator must be conversant with the current best practices and challenges that other countries have encountered in reducing emissions to ensure that common mistakes are avoided, and that enabling conditions are in place. This is often a challenge for small developing countries, and governments should have plans to ensure that technical expertise is available so that operator proposals for emissions management can be rigorously reviewed.

As the FDP is the basis for managing a field throughout its lifespan, it provides a key baseline from which the regulator can engage with the operator over 20-30 years. Thus, every stage of the project's life should be addressed, from initial design through regular maintenance and remediation programmes to detailing the decommissioning process. In countries such as Nigeria and Angola, the lack of comprehensive facilities maintenance and remediation is one of the major contributors to their emissions. It is particularly important that a robust and fully funded plan is in place for decommissioning, so that leaks and emissions can be detected and remedied even after production has ceased.

Having project-level GHG estimates from the design stage will also be critical to understand the impact on a country's NDCs. As noted earlier, new producers have very low absolute and per capita emission levels. This, however, is likely to increase drastically if sector emissions are not adequately addressed. NDCs are meant to be ratcheted up in the future and project-specific GHG management plans could serve as credible pathways for managing the impact of the sector on country-wide emissions. For example, if the country were to adopt a net zero approach as a criterion for FDP approval and there were rigorous measures to ensure compliance, the net countrywide emissions would not increase. The FDP could thus serve to ensure sector alignment with the country's NDCs.

Recommendations for new producers

- Recognise that incorporating technologies and standard operating practices at the design stage will be considerably cheaper than retrofitting mitigating technology later. The country's interests are best served by ensuring operators develop low emissions projects.
- A GHG management plan should be included as part of the operator's proposal for developing a field development plan. This plan should include the design, ongoing operation and decommissioning phases of the project's life.
- Governments should consider adopting a net zero approach as a criterion for FDP approval to ensure a country's emissions do not grow as a consequence of developing the sector.
- Ensure the GHG plan is aligned with the country's NDC.
- Make reducing emissions key to project design and ensure there is flexibility to upgrade as technology improves.
- Develop industry emissions forecasts based on project-level GHG management plans and inter-agency communication about them. This should help create a coherent approach to the development of NDCs.
- Equivalent high standards should also be expected of projects operated by NOCs.

D. Dealing with associated gas

Associated gas developments can be challenging in terms of reducing carbon emissions. Associated gas is natural gas emitted during oil production. It is an extra (and often unintended) by-product of an oil project and dealing with it is a complication involving additional expense. It is separated from crude oil at the surface by centrifugal separation or heating. Historically, to remove it as easily and cheaply as possible, associated gas was usually flared. However, this is no longer an accepted practice (although it persists). Operators and governments must identify a viable use for the associated gas before oil production begins or they are faced with a stark choice between permitting flaring or not developing the oil for which the project is designed. Projects with associated gas face higher risks of becoming stranded as a result.

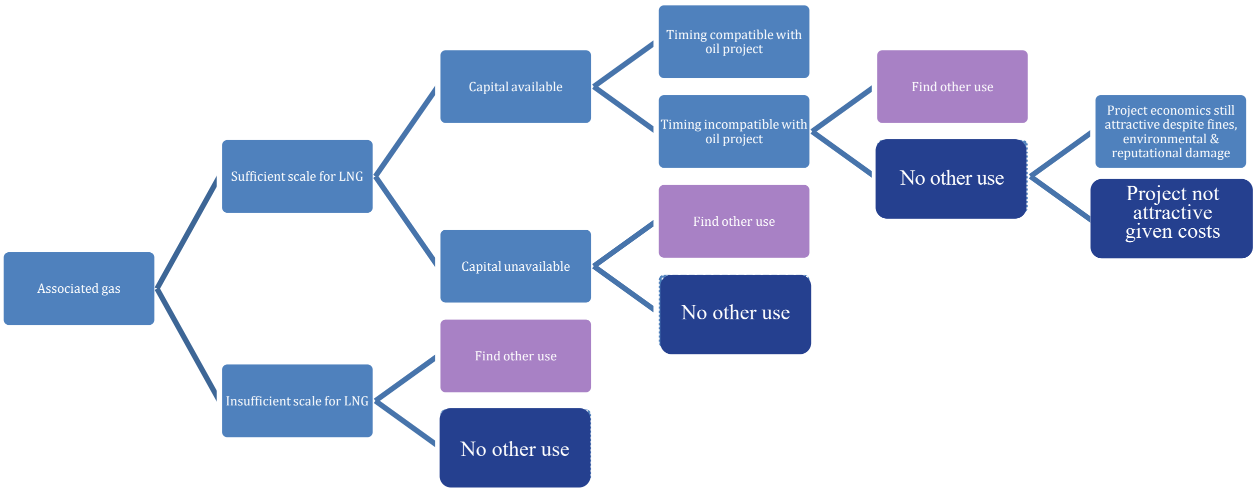
There are several options for managing associated gas without flaring). The gas could be:

i. Developed as liquefied natural gas (LNG);
ii. Reinjected into the reservoir;
iii. Produced and processed for liquefied petroleum gas (LPG) and condensates if the gas is wet;
iv. Supplied to the local gas market;
v. Exported via a p ipeline to a regional or export market;
vi. Used as a feedstock for products (e.g. hydrogen, methanol, gas-to-liquids or GTL conversion).

The most suitable option will depend on the specifics of the project. The timing of options to manage the gas is also critical as gas infrastructure typically takes far longer to build than oil infrastructure, which could cause problems and delays to the underlying oil project. This tension is particularly acute if the development of the oil project is being fast tracked.

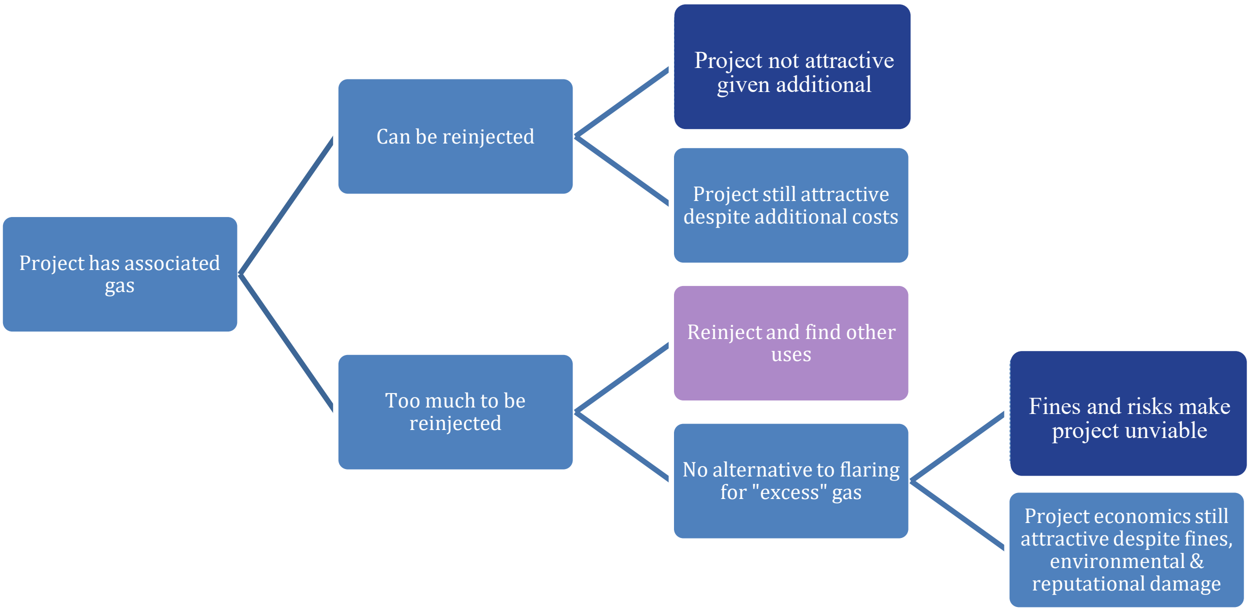
Producing LNG from gas

LNG projects are very large-scale, highly capital intensive and take many years to deliver (and also often run over time and over budget). Associated gas tends to be subscale for LNG, although the smaller floating LNG (FLNG) could possibly be viable, especially if associated gas can be aggregated from several projects in close proximity. This is untested so far, and only one LNG project in Angola uses associated gas. It is very unlikely that LNG is the most viable answer to the most associated gas problems.



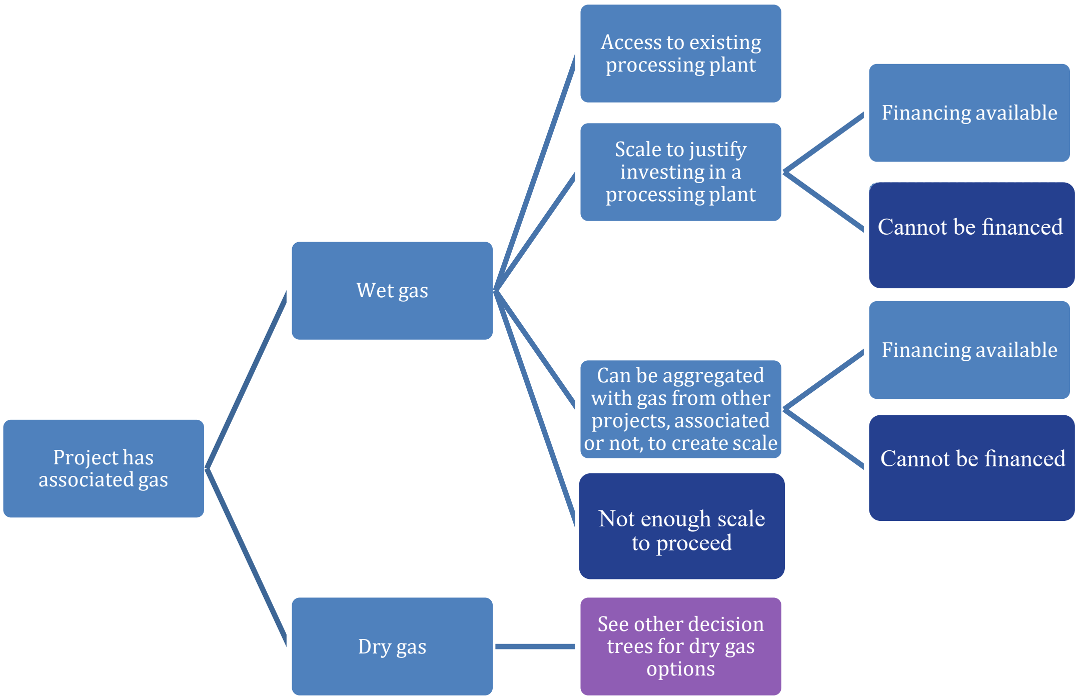
Gas used for reinjection

Reinjection is an option where the quantity of gas is comparatively small relative to the size of the oil discovery. If there is too much gas to be reinjected, and there is no other use for it, some flaring may be needed. The regulatory regime should provide for this with appropriate fines which should be consistent across the sector, without a special rate for associated gas. The oil company can then assess the economics of the project with the inclusion of those fines as an ongoing cost. For the government, this could create a conflict of interest: monetising flaring increases the risk that it could value fiscal returns over preserving the country's natural capital. However, a sufficiently high level of fines should also create an incentive for the operator to minimise flaring.



Gas used to produce LPG and condensates

This option for producing wet gas (see Glossary), depends on access to processing capacity and sufficient volumes (including whether it could be aggregated with wet gas from other projects to reach viable scale).

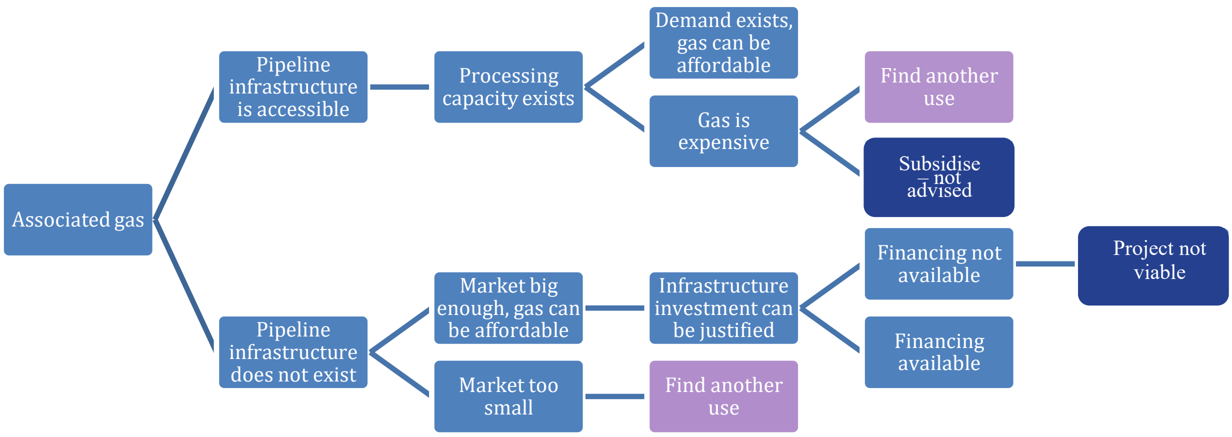


Gas used by the domestic market

Supplying associated gas to the domestic market is an attractive option where there are national energy gaps, but it is complex. A country should have a realistic gas masterplan to underpin this option, which considers the supply and demand of the gas market over time, and the relative market for and affordability of cleaner alternatives. From a climate change perspective, if gas is being introduced to a country's energy mix, it should be displacing an even higher carbon energy source, such as biomass, coal, and oil (which account for 82% of Africa's primary energy demand)[23]. If the masterplan is too pessimistic about demand, there will be insufficient investment upstream and gas that could have been produced will not become available to the domestic market. It can also be too optimistic, with over-investment upstream leading to more gas production than can be processed, and thus to flaring. This was the outcome in Ghana, where additional volumes of gas have been flared while a second gas processing plant is built. An excessively optimistic plan will also supply gas that is not affordable to domestic consumers, crowding out renewable projects that might have been deployed more affordably. There needs to be careful consideration of whether the gas would be affordable to end users, while still providing a reasonable return to the operator, pipeline owner, processor, gas retail company and utility, with credit risk at each of those interfaces. Domestic supply obligations can help with affordability, by allowing governments to take (some or all) royalties in gas rather than cash.

The availability of gas infrastructure reduces costs and risks significantly. Domestic use is indeed a preferred option for associated gas where the project is close to it. But despite a predicted doubling of gas demand in sub-Saharan Africa by 2040 in the IEA Stated Policies Scenario, the continent accounts for just 4% of global power supply investment and gas infrastructure investments are similarly restricted.[24] New infrastructure is capital intensive and increasingly difficult to finance - especially as multilateral development banks withdraw from fossil fuel investments.

Building pipelines also takes years, creating the problem of what to do with the gas in the meantime, as the oil project will be developed much faster. Conversely, if a government chooses to invest heavily in building the required infrastructure ahead of gas production, as Senegal is doing, it also takes on risks related to upstream production delays or disappointing production volumes.



International oil companies consider local gas projects risky, and many will avoid investing in assets with associated gas. Governments should understand the risks in order to manage them, which include:

[23] *IEA (2019), Total primary energy demand in Africa by scenario, 2018-2040, IEA, Paris https://www.iea.org/data-and-statistics/charts/total-primary-energy-demand-in-africa-by-scenario-2018-2040*
[24] *IEA (2019), Africa Energy Outlook 2019, IEA, Paris https://www.iea.org/reports/africa-energy-outlook-2019*

i. Government control tends to mean lower prices, which reduces the profitability of the project;
ii. Returns tend to be low, even with incentives;
iii. International financing is difficult to secure;
iv. Local currency presents a currency conversion risk;
v. Local contractors may not have sufficient expertise;
vi. Billing and payments are less certain (credit risk);
vii. Planning problems and potential for community disruption;
viii. Ongoing maintenance and safety issues;
ix. Not usually required as a condition of the concession.[25]

Gas exported to a regional market

This option depends on access to pipeline infrastructure. It is unlikely that associated gas, even if aggregated from a number of projects, could reasonably justify the costs of building regional pipelines. If such pipelines exist, and a project is very near them, it can make more sense to export gas than to transport it further to a domestic market.

Gas used as feedstock for hydrogen, methanol, gas to liquids (GTL)

This option depends on existing processing capacity and infrastructure to transport associated gas to the processing plant. Even if associated gas is aggregated from a number of projects, it is unlikely to be of sufficient scale to justify the large-scale investment of a new processing plant.

Recommendations for new producers

Dealing with associated gas is complicated, and in some cases there will be no good option for a productive use for the gas. It is also important to note that with infrastructure-intensive gas projects, there is a higher risk of stranding and any losses related to climate change risk will likely be borne by governments since the cost recovery basis of licences means that most of the first 7-10 years of revenues go to the operators.

- Scale is important and the following questions should be addressed as part of planning:
- Is the associated gas sufficiently small to be reinjected?
- Are returns still high enough, given the cost of dealing with associated gas, to justify the proposed project?
- Does relevant infrastructure already exist?
- Is the domestic market too small to justify infrastructure investment?

[25] *Adapted from Tom Mitro (2022), 'Associated Gas and Flaring Overview', Presentation at the NPG Training on Minimising Emissions from the Petroleum Sector, 1 July.*

- Even if the market is large, are there enough consumers able to pay a price for gas that provides a return for participants in the value chain? Is there a price for gas which creates both supply and demand?
- Is there good access to a regional market, geographically, politically and with access to existing infrastructure?
- Does processing capacity exist and is it accessible?
- Can associated gas from a number of projects be aggregated to create more viable scale?
- Does distribution capacity exist?

Once all these variables have been considered, each project must be assessed for viability from both an economic and a lowest possible GHG emissions perspective.

Overall recommendations for dealing with associated gas

i. Agree a national plan for expanding energy access with a focus on minimising emissions, on reliability and affordability.
ii. Develop a realistic gas masterplan that has been stress-tested for sensitivity to different events to ensure it is viable over the production's lifetime.
iii. Coordinate with the power sector and support gas and power pricing strategies that stimulate both demand and supply.
iv. Be realistic about payments and returns along the value chain.
v. Avoid subsidies and incentives as they distort investment decisions and can be difficult to change.
vi. Most importantly, be realistic about assessing the project's viability.

04

Renewables: Use in the petroleum sector and their catalyst potential for an integrated low-GHG energy sector

Another opportunity to reduce Scope 1 and Scope 2 emissions comes from using renewable energy (RE) in petroleum operations. Oil and gas projects typically use some of the produced hydrocarbons (e.g. diesel or gas) for heat, steam, and electricity in their operations. Replacing these fossil fuel sources of energy with renewable energy (e.g. electricity from solar or wind) therefore reduces the emission footprint of the operations. For example, by using electricity from the onshore power grid, emissions from the Norwegian offshore field Johan Sverdrup were reduced by around 80-90%, compared to a standard development employing gas turbines.[26] Equinor, the operator, forecasts that the field's emissions will be lowered by 460,000t CO2 per year.

At a project level, as always, it is important that the incorporation of renewables is planned at the beginning (this can be made a regulatory requirement), as imposing it later can be expensive or technically impossible (for instance, due to the space available on the platform). Whether renewables are suitable for all projects will depend on the project's scale, whether it is onshore or offshore, whether renewable energy is available from the grid or can be generated as part of or close to the project, for example to power electric vehicles.

Scale can enable the development of project-specific renewable power. Some new LNG projects, for example, are planning to develop mini-hydro plants as their main power source instead of using gas. Solar may be suitable for some projects, such as Uganda's heated crude pipeline, and wind turbines may be particularly appropriate for offshore installations. Cost can be an obstacle and it may make sense to incentivise such investments if it would make a valuable project viable or kick start investment in renewables for a region.

A critical first step to support the use of renewable power in oil and gas projects is therefore an assessment of the technical potential of various types of renewable energy to supply power to the project and their associated costs. There are several organisations that specialise in providing

[26] *https://www.equinor.com/energy/johan-sverdrup*

such assessments. For example, IRENA's resource assessments cover several countries in the New Producers Group and provide:

01	An assessment of the technical potential of various renewable energies, clustering the best areas into zones.	02	Estimated levelised cost of electricity from each RE source, based on assumptions around issues such as prevailing deployment costs, supporting infrastructure and grid connectivity costs.

During the 2022 NPG training on emissions, a key challenge identified was that there is very little or no data available for offshore wind potential for NPG countries. This means that whilst it is often touted as an easy solution to integrate into offshore developments, it remains an unknown for many.[27] Furthermore, detailed site-specific feasibility studies would still be required, even where resource assessments are available. This would include modelling using detailed local data to understand potential power generation capacity and costs. Given the extensive work that is required for such studies, government officials highlighted that the time to complete such assessments could take several years and would only be ready after they received field development plan submissions. This mismatch of data availability at the time of approving oil and gas projects is currently a significant hurdle for RE deployment in petroleum projects. Officials participating in the New Producers Group training highlighted the potential to use environmental impact studies as a key tool for regulators to require feasibility studies for RE use in operations to minimise pollutants.

The use of RE within petroleum projects could also serve as an important catalyst for wider RE deployment. If electricity demand is aggregated across several petroleum projects or across other industries (e.g. mining, manufacturing and residential use), larger-scale RE projects could become more economically viable. This could give rise to the development of Independent Power Producers (IPP) and possibly increase the availability of financing to such projects. Pricing would be a key enabler and specialist expertise would be required to incorporate power purchase agreements for RE projects. Such developments require a coordinated government approach to address the regulatory framework and to adjust pricing because any fossil fuel subsidies make RE less competitive.

Accelerating the deployment of renewable energy in petroleum operations can be supported by ambitious NDCs and strong political will. Development of renewables at the project and national levels should be informed by a national energy plan that clarifies the anticipated scaling up of renewables in the energy mix. This may have already been outlined in some detail in a country's NDC or in other national pledges. Such a plan must consider all the energy mix: oil, gas, and renewables, including the relative cost to end users, current and planned grid capacity and capital availability.

[27] *For example, there is no IRENA assessment of Suriname's offshore wind potential, but preliminary national data indicate it may not be a viable power source for oil and gas projects. This continues to be investigated but is unlikely to be incorporated in the first offshore project.*

Recommendations for new producers

- Develop a national energy plan in line with the country's NDCs;
- Develop an v e.g. authorising IPPs, developing power purchase agreements or reducing fossil fuel subsidies;
- Review plans regularly as technology, prices, demographics, affordability, and climate pledges change;
- Coordinate with power companies;
- Use an independent agency to assess potential renewable sites and choices;
- Use the petroleum regulatory framework to require renewables where they are technically and commercially viable;
- Ensure that the use of renewables is designed into projects from their inception.

05

Dealing with residual emissions

Considering that the sector can abate most of its emissions at an average cost of less than $50 per ton of carbon-dioxide equivalent (tCO2e),[28] companies and governments should only resort to relying on offsets and CCUS for residual emissions that are hard to abate.

5.1. Nature-based solutions

Oil companies invest in offset programmes to reduce their overall portfolio's net emissions and meet their net zero targets. All member countries of the NPG have set net zero targets for 2050 (with the exception of Ghana, Kenya, Albania, and Montenegro) and may similarly want to draw on REDD+ emissions reductions (conservation) and removals (afforestation/reforestation) projects to offset their national emissions – especially for:

01 Large reserve holder countries of Guyana, Mozambique, Mauritania, Suriname, Senegal, and Tanzania, whose growing petroleum emissions will affect national emission levels;

02 Countries aiming to stay carbon negative, such as Suriname and Guyana;

03 Countries with high forest cover, such as Suriname, Guyana, Papua New Guinea, Timor-Leste and Mozambique.

A strategic approach should be taken in the selection of offset projects, so they contribute to meeting national development goals.

Nature-based solutions deployed in-country can contribute to making a petroleum project net-

[28] *McKinsey & Company (2020). 'The future is now; How oil and gas companies can decarbonise', https://www.mckinsey.com/~/media/McKinsey/Industries/Oil%20and%20Gas/Our%20Insights/The%20future%20is%20now%20How%20oil%20and%20gas%20companies%20can%20decarbonize/The-future-is-now-How-oil-and-gas-companies-can-decarbonize.pdf*

zero, provided efforts are also directed at minimising its emissions, as described in previous sections. If oil companies invest in these national emissions offset projects, they should not retain the mitigation credit and consolidate it with the rest of the emissions and offsets at a company level - it should stay with the petroleum project.

Oil company carbon offset investments have come under increasing scrutiny. Many companies across high-emitting industries are relying on offsets rather than deploying substantive mitigation efforts to meet their emission goals. The cheap availability of offsets makes it an easier option than attempting to reduce emissions. Companies also benefit from trading offset credits, which are sold and resold many times. Offsetting projects are also criticised because they have broadly failed to deliver the results they promise (often due to questions around the true additionality and permanence of offset benefits), while enabling polluters to continue emitting unabated.[29] Governments should avoid exposing themselves to similar risks.

Recommendations for new producers:

- Countries should focus on mitigating petroleum sector emissions first and only turn to emissions reduction and carbon removal projects for residual emissions.
- These projects should be carried out in-country and aim to build lasting national benefits, such as improving clean energy access for citizens and restoring forests.
- Emissions reduction and carbon removal projects that aim to counter a country's petroleum sector emissions will be more credible to domestic and international civil society if they form part of a broader climate strategy that demonstrates ambition (through NDCs, zero routine flaring and methane leakage pledges, and a plan developed for scope 3 combustion-related emissions).
- Because these REDD+ activities aim to counter national level oil and gas emissions, they should not be sold on to the voluntary carbon market as their additionality would certainly come into question. National credits that go beyond the increased oil and gas footprint could be sold into the voluntary carbon market.[30]
- NOCs and governments need to retain mitigating credits and not allow reselling.

5.2. Carbon capture, utilisation, and storage (CCUS)

According to the International Energy Agency, "reaching net zero will be virtually impossible without CCUS." CCUS refers to various methods of capturing carbon dioxide (either from large point sources such as platforms, power plants, refineries or even directly from the atmosphere), putting the CO2 to use and permanently storing the emissions. While CO2 has been used in the upstream sector since the 1970s for enhanced oil recovery, this is not an effective solution for

[29] Perrine Toledano (2022). 'Carbon offset Voluntary Markets: Issues, Problems and Risks', Presentation, NPG webinar on National Carbon Offsets, 9 June. The World Economic Forum highlights 15 limitations of net-zero initiatives in "Net-zero: the risks and benefits for companies pledging to save the climate", 28 February 2022;
https://www.weforum.org/agenda/2022/02/net-zero-risks-benefits-climate
[30] See Glossary for definitions of terms used.

dealing with residual emissions as it results in additional carbon release to the atmosphere. For long-term beneficial climate effects, efforts need to be focused on using CO2 for products such as fuels, chemicals and building materials (rather than on any further extraction of fossil fuels).

To date CCUS has not yet been deployed at scale globally as the technology still needs to be demonstrated at commercial scale and faces significant regulatory barriers. Limited storage options have contribute to higher costs and there are few countries where CO2 storage assessments have been conducted.[31] Furthermore, public acceptance is not yet high. There are, however, a growing number of upstream petroleum pilot projects that have been enabled through CO2 pricing (e.g. Johan in Norway) and with government support.

For several mature petroleum-producing countries, CCUS forms a central plank of their strategy for adapting to a low-carbon future (e.g. Norway and Saudi Arabia). These plans hinge on linking CCUS to an industrial strategy, for example in the development of a hydrogen economy. Capturing CO2 associated with natural gas to produce hydrogen (blue hydrogen) is being pursued in tandem with green hydrogen (hydrogen produced with renewable energy).

Emerging producer countries should similarly understand the potential of CCUS applications in their national context. However, with the challenges described above (e.g. hurdles around commercialisation, regulation and public acceptance), CCUS is currently not a critical focus area for new producers. Given limited fiscal flexibility, socio-economic challenges post-pandemic, and the current immaturity of the CCUS industry, this is an understandable and pragmatic approach, as a government's scarce resources should first be focussed on proven technologies that are commercially viable. As the technology and markets are expected to evolve and gain critical mass, emerging producer governments should anticipate the conditions that would allow CCUS development, as described below.

Recommendations for new producers:

- Increase understanding of the potential for CO2 storage in geological formations. Include assessments where possible as part of the subsurface evaluation for projects (as part of GHG management plans).
- Where appropriate, consider broader industry feasibility studies rather than an individual project approach to reap economies of scale.
- Understand trends in CCUS technologies and regulatory requirements as the sector matures to inform national policies and plans.
- Evaluate enabling conditions and incentives for CCUS given the national context. Consider the introduction of carbon pricing.
- Consider CCUS as part of broader industrialisation policies.

[31] *OGCI is developing an independent assessment of geologic CO2 storage capacity. https://www.ogci.com/co2-storage-resource-catalogue/*

06

Conclusion and Recommendations

Emissions management is a new regulatory area for many governments and given their starting point, new producers have a major opportunity to establish leadership in the transition to net zero emissions. In order to develop their petroleum resources successfully in a carbon-constrained era, governments will need to recognise that minimising greenhouse gas emissions is not a “nice to have”, but increasingly an entry requirement or cost of being in business. Failure to recognise this and structure the development of their resources appropriately runs the risks of having to make expensive adjustments later, or of assets becoming stranded as climate change restrictions tighten. New producers have an opportunity to design their legal, fiscal, and regulatory frameworks to obtain the lowest emissions projects, rather than trying to amend existing systems, as established producers are having to do. This can be a fortuitous opportunity to develop their petroleum resources for the benefit of their populations, while minimising the climate impact of such development.

Recommendation:
Consider minimising emissions at every stage of the development of your petroleum resources.

Political will is the foundation of such a strategy, and may be embodied in international and domestic pledges, but must be backed by real support and resource to implement the necessary policies. Many countries have good intentions and desirable declarations but poor records of implementation. It is important that there is a clear regulatory framework, that responsibility for implementing it is appropriately allocated and adequately resourced, both in terms of legal power to enforce and resourced capacity to implement it. Coordination and communication between ministries, regulators, operators, and civil society will be vital. Governments should use available support and training, for example from the sources suggested in the appendix below.

Recommendation:
While political will is vital, governments must reinforce it not only with policies and a regulatory framework, but also with the resources needed for implementation, taking advantage of the help available.

It is crucial to design strategies to minimise GHG emissions into projects from the beginning, and to have a robust plan for all stages of a project from initial design, through all its operating stages and including fully-funded decommissioning. Governments have a number of levers to align the actions of operators (many of whom have net zero pledges of their own), including a fiscal system design and most importantly the approval or rejection of field development plans: they should use these levers to steer towards the outcomes which reduce emissions.

Recommendations:
Require steps to minimise emissions to be designed into all stages of a project from initial design to decommissioning. Use all the levers available to enforce this.

Governments should recognise that while there are many aspects to developing their petroleum resource in such a way as to minimise greenhouse gas emissions, the highest priority must be to prioritise near-zero routine flaring and robust leak detection and repair programmes. These can be implemented in a relatively short time, using tried and tested technology and will be lower cost if designed in at the outset than retrofitted later. Identifying and repairing leaks will reduce methane emissions significantly, while measurement and monitoring with precision are improved. Some strategies, such as leveraging renewable energy into the country's power system or building infrastructure for using associated gas can be developed for the longer term.

Recommendation:
The highest priority actions are to implement near-zero routine flaring and robust leak detection and repair programmes which will reduce emissions significantly while other policies are put in place.

Finally, governments must focus on minimising emissions as much as possible and only resort to offsetting for those residual emissions that cannot be addressed any other way, and they should ensure their operators do the same. By following these strategies, new producers have an opportunity to take the lead in configuring their petroleum resource development in a manner that should be resilient even in the face of increasing carbon constraints, thus managing their climate risk and benefitting their populations.

Recommendation:
Minimise emissions as much as possible, and only offset for truly hard-to-abate residual emissions

Overall Recommendation:
Make minimising emissions from petroleum central to all decisions about that sector. This will reduce the risks of your projects being stranded and allow you to develop your resource for the benefit of your population in an increasingly carbon-constrained era.

Appendix
FURTHER RESOURCES

Shayan Banerjee, Perrine Toledano (2016), 'A Policy Framework to Approach the Use of Associated Petroleum Gas', Columbia Center on Sustainable Investment, July.

CCAC Methane Technical Assistance Portal: Best practice guidance, modelling tools, reports, and a helpdesk. www.ccacoalition.org/en/content/methane-technical-assistance. CCAC also offer meetings of communities of practice on Fossil Fuels and National Planning. The Hubs are a forum for guidance and assistance on technological options, mitigation measures, funding opportunities, application of measurement tools, and policy development.

Deborah Gordon (2021), No Standard Oil, Oxford University Press.

IEA (2022), 'The Energy Security Case for Tackling Gas Flaring and Methane Leaks', June; https://www.iea.org/reports/the-energy-security-case-for-tackling-gas-flaring-and-methane-leaks

IEA (2022), 'Global Methane Tracker 2022' https://iea.blob.core.windows.net/assets/b5f6bb13-76ce-48ea-8fdb-3d4f8b58c838/GlobalMethaneTracker_documentation.pdf,

IEA (2021), 'Curtailing Methane Emissions from Fossil Fuel Operations', October; https://origin.iea.org/reports/curtailing-methane-emissions-from-fossil-fuel-operations. Identifies the different actions and initiatives that can deliver a 75% cut in methane emissions by 2030.

IEA (2021), 'Driving Down Methane Leaks from the Oil and Gas Industry'; https://www.iea.org/reports/driving-down-methane-leaks-from-the-oil-and-gas-industry. Offers a detailed 'how-to' guide for policy makers and regulators seeking to cut methane emissions.

International Methane Emissions Observatory (IMEO), a UN Environment Programme Initiative that offers countries capacity building support towards methane mitigation, assistance developing emissions baselines, and technical guidance for companies on methane measurement. https://www.unep.org/explore-topics/energy/what-we-do/imeo

IRENA, ‘Global Atlas for Renewable Energy – Geographic Information System (GIS)’; https://globalatlas.irena.org

Oil Climate Index plus Gas (OCI+), RMI, a resource to build understanding of the source of GHG emissions in the petroleum sector; https://ociplus.rmi.org

Oil and Gas Climate Initiative (OGCI), ‘Aiming for Zero Methane Emissions Initiative’; https://aimingforzero.ogci.com. An industry led methane pledge of particular relevance for national oil companies.

OGCI, ‘The CCUS Hub Website : Hub Playbook / Global Hub Search Tool’.
https://ccushub.ogci.com/

OGCI, ‘CO2 Storage Resource Catalogue’, https://www.ogci.com/co2-storage-resource-catalogue/

Oil and Gas Methane Partnership 2.0 (OGMP 2.0), a multi-stakeholder partnership to improve the accuracy and transparency of methane emissions reporting. Offers technical guidance on quantification and reporting of methane emissions. https://www.ogmpartnership.com/

Naadira Ogeer (2021), ‘Accelerating Methane Reductions in the Petroleum Sector’, Commonwealth Secretariat.

New Producers Group; https://www.newproducersgroup.online. Offers training on petroleum-related GHG emissions management and opportunities for peer-to-peer learning between officials from petroleum, environment, finance and energy agencies.

SkyTruth; https://skytruth.org. Produces flaring maps based on Nightfire data captured by the VIIRS instrument aboard NOAA’s Suomi NPP satellite. This data is made available free from the Earth Observation Group, Payne Institute for Public Policy, Colorado School of Mines.

World Bank, Global Gas Flaring Reduction Partnership (GGFR), Global Gas Flaring Tracker is a global and independent indicator of routine gas flaring; https://thedocs.worldbank.org/en/doc/1692f2ba2bd6408db82db9eb3894a789-0400072022/original/2022-Global-Gas-Flaring-Tracker-Report.pdf

World Bank, GGFR, ‘Imported Flare Gas (IFG) Index’; https://www.worldbank.org/en/programs/gasflaringreduction/global-flaring-data. An indicator that describes and compares the ’flaring footprint’ of different oil corridors from their source to the destination country’s border.

Glossary of terms

- **Additionality:** Indicates a GHG reduction that would not have happened without voluntary involvement. Additionality is essential for the quality of carbon offset credits.
- **Border tax adjustment:** Where a country (or bloc of countries) charges a fee on imported goods set by their carbon emissions to adjust for different climate change policies and make products competitive on comparable terms. For example, the EU Commission presented its proposal for a regulation establishing a Carbon Border Adjustment Mechanism on 14 July 2021. It aims to address the risk of carbon leakage caused by asymmetrical climate policies of non-EU countries (where policies applied to fight climate change are less ambitious than those of the EU).
- **Carbon compliance market:** Carbon markets are tools that are used to limit GHG emissions. As countries cap emissions, companies can purchase carbon credits beyond the acceptable levels. These credits represent carbon offset through an environmental project (such as reforestation or renewable energy). This allows companies to continue operating as they develop the technology needed to reduce their carbon output. The European Union's Emissions Trading System (EU ETS) is responsible for the bulk of the value of credits, but other emissions trading systems are emerging across the world.
- **Carbon Price: real or shadow:** A carbon price aims to allocate a cost to the carbon intensity of products, thus pricing the externality of climate change and creating an incentive to companies to reduce GHG emissions. A carbon price can be imposed by law across economies (becoming a real carbon price as in the EU) or it can be a notional price (or shadow carbon price) used by companies in their modelling of potential investments to see if they would still generate an adequate return if a real carbon price were to be introduced.
- **Enhanced Oil Recovery (EOR)** methods aim to maximise ultimate recovery from a field over the long term. They may include gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide (CO2) that expand in a reservoir to push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improve its flow rate (source: US DoE).

- **Fugitive emissions** are unintentional and undesirable emissions, leaks or discharges of greenhouse gases (e.g. refrigeration, air conditioning units).
- **Process emissions** are released during industrial processes and on-site manufacturing.
- **REDD+:** A framework created by the UNFCCC Conference of the Parties (COP) to guide activities in the forest sector that reduce emissions from deforestation and forest degradation, as well as the sustainable management of forests and the conservation and enhancement of forest carbon stocks in developing countries. It aims at the implementation of activities by national governments to reduce human pressure on forests that result in greenhouse gas emissions at the national level, but as an interim measure also recognises subnational implementation. The implementation of REDD+ activities is voluntary and depends on the national circumstances, capacities and capabilities of each developing country and the level of support received (source: UNFCCC).
- **Scope 1 emissions** are the direct result of activities that occur from owned or controlled sources.
- **Scope 2 emissions** are indirect emissions from the generation of energy purchased from a utility provider.
- **Scope 3 emissions** are all indirect emissions - not included in scope 2 - that the organisation is indirectly responsible for, up and down its value chain including its end use by others.
- **Stranding, Stranded Assets** are assets, projects or investments which become worthless as regulations or circumstances change. For example if a gas project can only produce gas with very high emissions, it will be stranded if carbon taxes are introduced which make it too expensive to produce profitably.
- **Voluntary carbon market (VCM):** Voluntary carbon markets are just that – voluntary. Individuals or organisations choose to purchase carbon credits to reduce their emissions (but are not legally obliged to do so). The VCM is expected to continue to grow as increasing numbers of companies incorporate carbon neutrality goals and other climate commitments into their climate strategies.
- **Wet gas** has more than 15% non-methane gases, for example ethane, propane, butane.

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