Flaring management—a framework for governments and regulatory bodies

This section provides a framework to help national governments address routine flaring through legislation and incentives when sanctioning new hydrocarbon development projects. The framework will also be of benefit in promoting ideas for new initiatives that may encourage the development of gas monetization projects for existing operations.
This section provides a framework for national governments to address routine flaring of associated gas by structuring laws, programs and incentives to eliminate its use when new ‘greenfield’ hydrocarbon development projects are sanctioned. For legacy operations, the path to reducing, and eventually eliminating, associated gas flaring can be more challenging because it involves existing operations working under existing laws, contracts and financial incentives. Nevertheless, the concepts embedded in the framework can offer ideas on new government initiatives or practices that may catalyze the development of gas monetization projects.

Figure 22 Framework for monetizing associated gas resources

The framework covers the following elements:

- **Institutional set-up:** An organizational structure with an agreed mandate and sufficient resources is essential to achieve a sustainable flaring reduction program.
- **Regulations and guidelines:** Rules are needed to define the transactional and commercial structure, and are supported by implementation guidelines.
- **Flaring and production data management system:** Actions by government entities, oil and gas operators, value chain partners and investors are driven by well-defined and transparent data.
- **Flare gas-to-market project origination:** Real progress on reducing flaring relies on a host of actors that come together to effectively execute in-field gas utilization projects.

Overall, this represents a new GGFR framework for monetizing associated gas resources. The traditional model was a bottom-up approach, initiated at the producer level. Projects that went beyond ‘own consumption’ of gas by the producer typically faced delays related to the creation of ‘first-of-their-kind’ commercial structures due to missing institutional elements or unhelpful legal and regulatory provisions. The new model starts by assuring that a conducive legal and regulatory framework exists, and that more standardized commercial structures, which leverage public finance and attract private capital, can be used to meet the risk/reward expectation of the market. These foundational elements create a defined and level playing field on which developers can delineate projects and attract investment. Figure 22 presents the key elements of the framework that are covered in more detail in this section. It illustrates how the key structural elements (set-up, regulatory framework and data management) support the process elements (project origination, project definition and funding) that produce beneficial outcomes.
INSTITUTIONAL SET-UP

The following sections discuss the key elements involved in establishing an effective national capacity to manage the beneficial utilization of a country’s associated gas resources.

Internal and external stakeholder mapping

Defining needs and priorities is among the most important first steps in instituting a national framework for associated gas management and utilization. To facilitate the identification of needs and priorities, a robust stakeholder identification and engagement process is invaluable. This exercise requires a thorough consideration of regional perspectives, requirements and constraints. It promotes a participatory process, captures ‘hidden’ stakeholders, and leverages professional, expert and other human and organizational resources. It includes the mapping of key partners to engage with in the capacity development process, and a discussion on development priorities.

The primary in-country stakeholders include government ministries (such as those responsible for petroleum/energy, finance and environmental protection), regulators (which may not be a part of the ministries) and other related development-focused ministries. The input from these key ministerial entities should drive the definition of needs and priorities. However, to validate assumptions from business and societal perspectives, supplemental input should be sought from others, including scientific and technological institutions, chambers of commerce or industry associations, and certain non-governmental organizations that represent large or otherwise important constituent populations. For example, these non-ministerial stakeholders can offer important feedback on how priorities and goals mesh with ongoing national progress on relevant SDGs.

A country’s energy profile, including its consumption, owned resources and production/generation are rarely managed in isolation from the broader regional (if not global) context. Consequently, it is important that any effort to define needs and priorities looks beyond a country’s borders. Civil society organizations that operate globally and promote good practices in areas such as investment, education, inclusiveness, competition, good governance, anti-corruption and fiscal policy can offer deep technical and policy experience and advice. Examples include the UNDP, the United Nations Environment Programme (UNEP), and the Organization for Economic Co-operation and Development (OECD). Also of importance are the international financial institutions and multilateral development banks that provide financial and other resources for energy development within the context of broader sustainable development goals. Examples of such institutions include the World Bank/International Finance Corporation (IFC), the European Bank for Reconstruction and Development (EBRD), the Asian Development Bank (ADB), among others.

At the early stages of the stakeholder engagement process, it is important to establish accountability, i.e. who will do what, who will ensure that it gets done, and what the consequences will be if progress stalls. Ultimately, an effective capacity building process will encourage participation by all those involved. Engaging stakeholders who are directly affected creates shared ownership and allows for more effective decision-making. Ideally, accountability should flow both upwards and downwards through clearly stated goals and responsibilities, using local conventions and systems for ensuring accountability. However, if an external entity is involved in facilitating the engagement process, effort should be made to avoid creating parallel systems that undermine or compete with the local systems.\[155\]

Organizational structure—design and implementation

The UNDP considers the organizational level of a nation’s capacity (in any area) to be comprised of the internal policies, arrangements, procedures and frameworks that allow an organization to operate and deliver on its mandate, and that enable the coming together of individual capacities to work together and achieve goals.\[155\] With respect to associated gas flaring reduction and utilization, the section on Regulatory framework approaches on page 74 covers policies, arrangements and procedures.

\[11\] Regulators can often be more accessible sources of information than ministries on matters such as price controls, local content requirements, permitting requirements, etc.
Fundamentally, there is no single best institutional alternative for how to effect control over flaring reduction. One approach is to create a durable and adaptable organization for associated gas flaring reduction within the nation’s state-sponsored oil company, oil ministry or environmental protection ministry. Another is to establish an interdisciplinary task force comprised of specialists from all relevant ministries. (Eventually, the task force could transition into a permanent structure after completing certain capacity building tasks.) Ultimately, however, the most important factor is likely to be the evaluation and implementation process employed.

Each country is unique, with specific opportunities and challenges. External forces and numerous country-level characteristics, including political stability, resource base, trade, financial attractiveness, etc., will establish the context within which any work to redirect associated gas from flares to productive use will take place. Extending the work of the UNDP on general country-level capacity building to the management of associated gas in particular, suggests that there should be a focus on strengthening existing core capabilities within a nation’s governance framework, rather than creating new entities or relationships simply because they work well for other nations.

Some examples of specific questions relating to associated gas are listed below:

- **Leadership** — the ability to influence, inspire and motivate others to effect progress, and to anticipate and respond to change:
  - On the disposition of associated gas, do producers receive mixed messages from the oil ministry and the environmental protection ministry?
  - If so, which one carries more importance? Is the country’s position with respect to climate change consistent with its energy development strategy?
  - What role does the national oil company play in setting county-level commitments on climate change?
  - Does the country have a clear message on the importance of implementing the SDGs?

- **Knowledge** — the combination of facts, expertise, know-how and reasoning ability that people possess, and which can be shared within an organization:
  - Does the country maintain a data system for managing associated gas and flaring?
  - Are there experts within the government that can offer direction, guidance and other technical support for flare gas reduction projects?
  - Does the country’s finance ministry have the capacity to support finance from external development institutions?

- **Accountability** — the condition that exists when responsibility for actions is accepted:
  - Are the regulations that apply to associated gas flaring enforced consistently?
  - Does the oil ministry allow the national oil company or concession holders to delay implementation of agreed-to gas utilization projects?
  - Is the national oil company treated in the same way as third-party concession holders if flaring reductions targets are not met?
Capacity building

The UNDP sees capacity development as a process to strengthen or maintain the government’s capabilities to set and achieve development objectives over time. The process should be generated and sustained from within the affected organizations, not by third parties or consultants. A five-step approach is often used as a model, as shown in Figure 23 and discussed below.

Step 1: Engage stakeholders on capacity development

The stakeholder identification and engagement process, described under Internal and external stakeholder mapping on page 71 is a critical first step and a necessary supporting process throughout the full cycle. It includes the mapping of key partners to engage with in the capacity development process, and a discussion on development priorities. It often involves consensus-building on the need to establish capacity development as a political priority.

Step 2: Assess capacity assets and needs

When developing an effective capacity building initiative, some fundamental questions need to be asked in the assessment phase. For example: What kinds of technical capacities related to flaring reduction and gas utilization/monetization are needed? Why is the capacity needed? What will be its purpose? What entities or organizations are responsible for maintaining the capacities? A systematic capacity assessment of desired capacities compared with existing capacities can help to determine which capacity efforts should be prioritized.

In addition to the technical capacities, the assessment should also consider the functional (i.e. management) capacities that provide the foundation for a government organization’s ability to execute its technical mission. These functional capacities are summarized in Annex IX.

Step 3: Formulate a capacity development program

The findings of a capacity assessment can provide the starting point for formulating a capacity development response. This response involves an integrated set of deliberate and sequenced actions embedded in a program or project to address three guiding questions:

- Why more capacity? This concerns the priorities of capacity development.
- Capacity for whom? This addresses whose capacities need to be addressed, whether a ministry (or several), a department or a unit.
- Capacity for what? This addresses what capacities (both functional and technical) are to be developed.

A necessary part of the planning effort is the formulation of a set of indicators to monitor progress of the capacity development response. Each indicator should focus on intended outcomes — i.e. the desired change in capacity — and should have a baseline and target(s). Another necessary element is a budget that reflects the work to be done to facilitate the degree of capacity development that is desired.
Step 4: Implement a capacity development response

The execution of the response plan involves the work to turn intent into practice. Although this step is inherently outcome-focused, its success will require the opportunity for stakeholder feedback and mid-course adjustment loops. The indicators developed at the outset of the transformation process provide the guideposts to prevent drastic deviations. In addition, to ensure the sustainability of changes that are made — whether to strengthen existing capacities or build new ones — implementation should be managed through existing national systems and processes, rather than through new, parallel systems that would likely not be maintained.

Step 5: Evaluate capacity development

Post-implementation, there will be a more effective national capacity to manage the beneficial utilization of a country’s associated gas resources. It is incumbent on the institutions and the affected stakeholders (e.g. production companies, other business partners, local communities) to assess whether the overall outcomes are delivering the desired advancements. Use of the SDGs can facilitate such an evaluation.

REGULATORY FRAMEWORK APPROACHES

It is important that the government sets out a clear resource management and environmental policy, in line with the country’s development goals. As part of developing a relevant policy, it is recommended that the government specifies the strategy for reducing flaring and venting of associated gas, and the role that this can play in achieving the overall environmental and resource management objectives.

The organizational level of a nation’s capacity comprises the internal policies, arrangements, procedures and frameworks that allow an organization to operate and deliver on its mandate, and that enable the coming together of individual capacities to work together and achieve the required goals. If these exist, and are well resourced and well aligned, the capability of an organization to perform will be greater than that of the sum of its parts.

This section offers a brief synopsis of the foundational concepts, including policies/legislation, institutional arrangements and regulatory practice. Also covered are effective practices that have been implemented by governments in addressing the flaring of associated gas. It leverages earlier work by the GGFR[158] and updates it with current developments.

Policies

Generally, countries establish separate primary legislation for natural resource management, including hydrocarbon production and environmental protection. This legislation can either address flaring of associated gas explicitly, or may do so indirectly by delegating the responsibility to regulatory agencies or ministerial bodies. These agencies, in turn, need to establish a framework to deal with gas flaring through secondary legal instruments such as regulations, codes, licenses and guidelines. The advantage of incorporating detailed gas flaring and venting regulations in secondary legal instruments, rather than in primary legislation, is that those instruments are more flexible and adaptable to changing conditions of oil production, natural resource management and environmental protection.
As an example, Algeria Law No. 19-13 prohibits flaring and venting unless a specific authorization is granted by the ministerial agency responsible for the development of hydrocarbon resources, or the activity qualifies for an exemption. It also establishes a non-deductible tax for each thousand cubic meters of gas flared, and delegates gas flaring regulation details to a ministerial agency. For those cases where a country’s policy framework is still developing, or where some components have not yet been finalized, certain options may work better than others in the local context. Figure 24 illustrates some of the high-level possibilities that deserve consideration.

One element that should be incorporated into legislation governing new oil projects is a provision that requires associated gas utilization be included as an integral part of the field development plan. Addressing flaring and venting retroactively is more costly and often more technically challenging than doing so at the inception of a new field development plan.

In addition to policies addressing gas flaring, primary legislation, or in some cases a country’s constitution (or equivalent), specifies the legal ownership of associated gas resources. This has important implications for the latitude that individual companies — acting under some form of a concession agreement — may exercise in monetizing associated gas streams. Where ownership of associated gas remains with the host government, use of the gas resource by the production operator is often limited to in-field consumption coincidental to the production of oil resources. Typical examples include use as fuel for well-site electricity generators or boilers/heaters in gas processing plants, as an injectant to maintain reservoir pressure, or as the working fluid in gas lift operations or pneumatic control systems.

Other options for utilizing associated gas typically require that the operator obtains approval from the national energy ministry. If the alternative creates or significantly expands basic infrastructure (e.g. gas distribution networks or the electricity grid), it is highly likely that other agencies will have a role to play in the approval process. In such cases, a critical review of primary legislation beyond the hydrocarbon sector may be necessary. Also needed is a determination of how legislation should address the price of associated gas. Often, associated gas, especially in situations of long-lived legacy flaring, cannot compete with non-associated gas on equal terms due to quality or deliverability factors. New or modified legislation may be needed to allow decoupling of the pricing structures and the implementation of market pricing for associated gas.
After the high-level market-enabling questions have been addressed, consideration will need to be given to financing and fiscal issues. If external financing (e.g. through a multilateral development bank — see the discussion in the section on Third-party funding opportunities on page 94) is required for the alternative use of associated gas, does the national government have the institutional capacity to qualify for, and/or manage, such funding? Regardless of the source of financing, there is a need to support the project’s financial viability, balancing the required capital expenditure and ongoing costs of the alternative use of associated gas with the anticipated revenue steam. Establishing laws that strengthen accounting frameworks or promote greater transparency may be needed. Amendments may also be required to deal with fiscal policy issues, including royalty payments, taxes and tax incentives. If a third party or a new JV partner are involved in commercializing an alternative use of associated gas, the existing legislative framework will need to be reviewed to determine how such an arrangement can be accommodated.

Additional considerations are how the alternative use of gas helps to achieve progress on the country’s key SDGs and on any relevant country-specific GHG emission reduction target.

Institutional arrangements

In a mature governmental framework, agencies or ministries that regulate hydrocarbon production, and those that regulate the environmental impacts of gas flaring, exhibit the following characteristics:

- They will have clearly defined responsibilities and are accountable for their fulfilment.
- They are independent from regulated operators.
- They adopt clear and efficient regulatory processes concerning gas flaring and venting.
- They will be properly staffed and financed to execute responsibilities and enforce compliance with regulations.

A country’s energy ministry establishes hydrocarbon production regulations for the exploitation of oil and gas resources to achieve a sustainable beneficial outcome for its citizens. This includes balancing the expectations of companies, landowners, resource owners and affected communities while also considering the natural environment. Generally, authority for flaring associated gas is derived from legislation authored by the energy ministry, but it is common for the environmental impacts from gas flaring to be regulated by the environmental protection ministry. In such cases, where the responsibilities are shared across two or more agencies, there is a need for clear definition of the respective roles and responsibilities of the institutional entities to ensure effective cooperation, and avoid overlapping or conflicting requirements or gaps in enforcement.

Other institutional and structural conditions can enhance the prospects for productive use of associated gas resources and the reduction of environmental impacts caused by routine flaring. For countries where non-associated gas is readily available, to limit the unnecessary flaring of associated gas, special consideration could be given to prioritize the utilization of associated gas, as described below:

- Associated gas development should be integrated into the country’s energy sector strategy. For all new oilfield projects, the regulations governing the field development planning and authorization process should include requirements for the utilization of associated gas, with no authorization of routine flaring or venting.
- Promotion of critical local gas utilization projects is needed to ensure fast acceleration of the gas market. It is important for government to facilitate local gas utilization programs and policies.
- The development of local infrastructure, either by government, public/private partnerships, or private investors should be listed as a priority government objective. Regulations could be structured to allow multiple options for developing gas infrastructure, either by government, public/private partnerships (e.g. build-operate-transfer) or private investors.
Incentivizing flaring reduction projects by proposing favorable fiscal policies such as reduced royalties, accelerated depreciation, investment credits, and tax credits or deferments could be used to encourage the consideration of all gas utilization options. In addition, external financing could be used to offset the impact of high up-front capital costs and help support investment returns.

To de-incentivize the practice of gas flaring, consideration should be given to setting a volume-based fee on all gas that is routinely flared. Volumes flared for safety purposes could be exempted. Fee levels could be set so that investment in flare and vent reduction is more attractive than paying the fee.

For flaring at legacy oilfields, reductions require a realistic flare/vent elimination deadline that is built on a cooperative approach in consultation with key stakeholders, particularly oilfield operators.

Developers that advance projects to monetize gas, including gas export, should be granted open access to gas processing and transmission infrastructure, and the gas market should be based upon transparent, market-based pricing. For gas-to-power projects, there should be open access to the grid infrastructure to facilitate the sale and distribution of electricity.

The finance ministry can actively lead efforts to modernize monetary and exchange rate governance and policies, strengthen the country’s ability to negotiate and implement agreements, improve the investment climate, reduce internal impediments to trade, and adopt growth-oriented development strategies that are consistent with the SDGs. Such efforts build confidence in prospective sources of external finance.

**Regulations**

The authority for secondary legal instruments such as regulations, codes, licenses and guidelines that address associated gas flaring is derived from primary legislation. Both the energy ministry and the environmental protection ministry can implement regulatory programs to complement a robust market framework, as long as they do so in a coordinated manner and give operators and investors confidence that there is a level playing field for all. Key issues are presented in Table 12.

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**Table 12  Barriers and regulatory options**

<table>
<thead>
<tr>
<th>BARRIERS</th>
<th>ISSUES THE REGULATORY FRAMEWORK SHOULD ADDRESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas ownership</td>
<td>● Ownership of the associated gas and/or flare gas</td>
</tr>
<tr>
<td></td>
<td>● Differentiate between associated gas for own consumption, associated gas taken to market with producer’s investment, and flare gas that could be monetized by third parties</td>
</tr>
<tr>
<td>Access to flare gas</td>
<td>● Terms and conditions under which third parties can obtain access to flare gas</td>
</tr>
<tr>
<td></td>
<td>● Process to obtain permit/rights/ownership of flare gas</td>
</tr>
<tr>
<td></td>
<td>● Infrastructure interconnections terms and conditions between flare site and midstream flare monetization project</td>
</tr>
<tr>
<td>Access to existing infrastructure with spare capacity</td>
<td>● Free access to existing infrastructure with spare capacity against fair and established compensation</td>
</tr>
<tr>
<td>Flare gas pricing</td>
<td>● The associated gas price should be market-driven</td>
</tr>
<tr>
<td></td>
<td>● Consider the impact of subsidized fuels or derived products (such as electricity) on the demand for associate gas</td>
</tr>
<tr>
<td></td>
<td>● Where an abundant supply of non-associated gas is available, incentives to help prioritize utilization of associated gas should be considered</td>
</tr>
</tbody>
</table>
Regulatory programs can follow one of several models:

- **A prescriptive approach:** This approach is based on specific and detailed regulatory requirements, procedures and operational processes. Creating detailed technical regulations is a challenging task for an agency, especially one with limited experience, and can involve a lengthy process of proposal, comment, review and finalization. Strict enforcement tools and penalties are often applied to promote compliance.

  A prescriptive approach can minimize the likelihood of failure to achieve the desired outcome (elimination of flaring by a certain date). However, the successful achievement of such a goal may come with high transactional costs because predetermined methods to achieve compliance may be inflexible, or technology implementation costs may be high.

- **A performance-based approach:** This relies on consensus and cooperation between operators and the regulator in setting objectives and targets. The operator then has the responsibility to define a program to achieve these targets and to provide evidence demonstrating that it is complying with the agreement. Typically, the enforcement authority focuses on compliance assistance rather than the imposition of penalties or other sanctions, unless progress on targets stalls.

  A performance-based approach affords a great deal of flexibility to regulated companies in achieving the desired outcome (elimination of flaring), but it does not guarantee that it will occur by a particular date, if at all. Company costs can be much lower than under a prescriptive regime, and there is greater opportunity for innovation in practices and technologies. However, there is a greater burden on agencies to review plans, monitor progress and provide technical assistance than under a prescriptive approach.

- **An economic approach:** This approach relies on pricing mechanisms that harness the economic self-interest of the various entities in the marketplace to achieve the desired policy outcome (elimination of flaring). To encourage actions, market forces are supplemented by fiscal policies such as tax credits, investment incentives or, in the case of flaring, a carbon emissions tax or carbon credit instrument.

  An economic approach can be an efficient way to achieve changes in behavior. If structured appropriately, with reliance placed on market pricing as the primary driver for change, it requires little oversight from agencies. However, if market pricing alone is insufficient to achieve the desired outcome, or as the number and complexity of new fiscal instruments increases, so too does the level of oversight from government entities—from monitoring for fraud to administering new pseudo-market systems, e.g. carbon credit trading.

The following features will need to be addressed by the development of specific regulatory language (prescriptive approach) or as a required element of a flaring management plan (performance-based approach):

- **Definitions and boundaries**
  Because oil and gas production is a complex, multi-step process, the regulatory program should articulate which of these activities is subject to regulation. Definitions for equipment, systems operating conditions, monitoring methods and reporting requirements provide a common language and reliable basis for decision-making.

- **Permits/authorizations/approvals/exemptions**
  For new oilfield development projects, flaring is addressed more effectively, and at lower cost, if it is considered at the field development planning stage. Prior to obtaining ministerial approval for field development, operators should develop associated gas utilization options and commit to the construction of all necessary facilities. For existing fields, each operator should be required to develop a plan with clear targets for the cessation of routine flaring activities, including alignment with the ‘Zero Routine Flaring by 2030’ initiative. In the interim, agencies will need to grant authorizations (permits) on a flare-by-flare basis. Exemptions for flaring, for unavoidable technical reasons or to maintain safe operations, need to be specified.

- **Measurement and reporting**
  To enable government agencies to assess whether oil and gas is being produced in a manner that is aligned with resource extraction and environmental protection policies, operators will need to provide accurate information about gas flaring. Agencies must specify the protocols for measurement, monitoring and reporting to assure consistency across all operators. Metrics and indicators should be defined, such as the number of flaring incidents, duration of flaring, volumes of gas flared, and emissions. Tools should be established for reporting information to government authorities, and should specify the granularity of the data (e.g. a company roll-up versus site-by-site data), the frequency of reports, the data systems to be used, etc.
Flaring management—a framework for governments and regulatory bodies

Monitoring and enforcement

The ministerial agencies responsible for regulating associated gas flaring need to have adequate monitoring and enforcement powers and corresponding tools. These elements establish a framework within which operators are encouraged to align operating practices with national goals. In addition, guidelines for practical implementation of regulatory provisions, including obtaining gas flaring permits and exemption criteria, flare gas measurement, data management and reporting obligations, royalty payments and tax reporting, etc., promote and facilitate operator compliance at the field level.

Monitoring

- Effective agency oversight requires accurate information about the production, use and disposition of associated gas, including the nature, frequency and volumes of gas flared. The agencies should have the right of access to flaring sites and operational data. With this information, the energy ministry and the environmental protection ministry have a common basis for monitoring operator performance and taking enforcement actions if needed. (Operator reporting and agency management of the reported data are covered under Flaring and gas production data management system on page 85.)

- Authority for agency oversight of activities needs to be included in the legislation that addresses energy resources and environmental protection. Agency mandates should be broadly defined and include the right to perform on-site inspections and audits of operating records and underlying data.

- The obligation and procedures for operators to measure and report data on the production, use and disposition of associated gas should be included in the primary legislation that addresses energy resources and environmental protection, and/or in the corresponding secondary legal instruments, i.e. regulations, for each area. These obligations need to be enforceable.

Enforcement

- The legislation that addresses energy resources and environmental protection should include provisions to allow enforcement of all legal/regulatory obligations, giving agencies the power to impose penalties or fines, including termination of the operator’s production license, in cases of non-compliance.

- Enforcement proceedings should follow a structured, fact-based process, and will need to provide an opportunity for the operator to challenge allegations of non-compliance through administrative channels and in court.

Lessons learned from international experience

Generic lessons learned from experiences in oil producing countries, such as Algeria, Canada, Norway, the UK and the US were documented by the GGFR in 2009.[159] These include the following examples:

- Oil and gas legislation and concessions/licenses should be clear, comprehensive and unambiguous on the treatment of associated gas.

- Fiscal terms should encourage the consideration of all gas utilization options, including those projects where governmental incentives could mitigate the impact of high up-front capital costs and marginal returns.

- The gas market should be based upon transparent energy pricing that is market-based.

- Oil and gas producers should have the right to monetize gas, including gas exports, and have open access to infrastructure — including gas processing and transmission facilities, and electricity grids (to sell electricity produced on-site from associated gas).

- Flare and venting regulation should be clear, with effective monitoring and enforcement. Such regulations are necessary to complement a robust market framework that should include investment incentives to give operators and investors confidence that there is a level playing field for all.

- For new oilfield projects, the regulations governing the field development planning and authorization process should include requirements for the utilization of associated gas, with no open-ended option for routine flaring or venting. Associated gas development should be integrated into the country’s energy sector strategy for all new oilfield projects.
For flaring at legacy oilfields, reductions require a comprehensive, measured approach that incorporates the foregoing elements, along with the establishment of a realistic flare/vent elimination deadline that is built on a cooperative approach in consultation with key stakeholders, particularly oilfield operators.

**North America**

**United States**: In 2019, North Dakota and Texas together accounted for 85% (or 1.3 billion cubic feet (bcf) per day) of the reported US vented and flared natural gas. Venting is banned in North Dakota and restricted in Texas. Despite a variety of US federal agency regulatory initiatives, legal challenges and court decisions during the 2016–2020 period, the primary regulations covering flaring of associated gas are those that exist at the state level.

State agencies in Texas and North Dakota have adopted regulatory requirements to drive gas utilization, and are working with oil producers to limit the need for flaring without shutting down or affecting crude oil production. In February 2021, the Texas Methane & Flaring Coalition issued a statement supporting a goal to eliminate routine flaring by 2030. In North Dakota, oil companies must capture a certain percentage (91% as of November 2020) of the gas produced by their operations. An agency order imposes flaring restrictions, and requires upstream firms to create gas capture plans prior to drilling, track and report their status, and draft improvement plans if goals are not being met. The order also seeks to improve midstream firm planning decisions by mandating semi-annual meetings, and by requiring upstream firms to provide production forecasts to midstream firms.

In addition to the state-level regulations, the US EPA has developed a voluntary emission reduction program, the Natural Gas STAR Program, which is aimed at implementing methane-reducing technologies and practices, and encouraging organizations to voluntarily document their emission reduction activities. Through this voluntary program, the US EPA and the Natural Gas STAR Program partners are continuing to improve performance, increasing natural gas supply, saving money and protecting the environment. This program also provides recommended technologies to reduce methane emissions, and gives detailed fact sheets about the economic and environmental benefits of utilizing the technology. From the inception of the program through to 11 January 2021, partners to the program had eliminated 1,700 bcf of methane emissions by implementing 153 cost-effective technologies and practices. In 2020 alone, partner activities resulted in emission reductions of 21.2 bcf.

One of the technologies featured in the Natural Gas STAR Program is an electronic flare ignition device. This technology replaces the intermittently or continuously burning flare pilot with an electrical sparking pilot. These pilots require low electrical power that can be supplied from a solar-rechargeable battery in remote sites. The electrical sparking pilot alleviates methane emissions that occur from the leaking or venting of un-combusted natural gas through an unlit flare. A traditional flare would normally experience periods where the flare is unlit due to flare pilot flames occasionally being blown out by high winds. The primary economic justification for implementing this technology is the value of the fuel gas savings. Flare pilot flames require approximately 70 cubic feet of methane per hour, meaning that yearly fuel gas savings could reach 652,000 cubic feet, assuming that a single pilot is blown out for 24 hours per year and the methane content in the fuel gas is 94%. Based on these fuel gas savings and the ease of installation, the cost of using this technology could potentially be paid back in less than a year.

**Canada**: Gas flaring and venting in Canada is generally a matter of provincial jurisdiction meaning that, for example, the Alberta Ministry of Environment and Parks, a government body, is in charge of regulating emissions in the province and for setting air quality standards. These standards are then applied by the take-away Regulator (AER) to set upstream petroleum industry gas flaring and venting targets. The AER also allows and encourages the participation of industry, public, environmental non-governmental organizations (ENGOs) and regulators to help with

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12 The Texas Methane & Flaring Coalition, which includes seven trade associations and more than 40 Texas operators, was formed to develop industry-led solutions designed to mitigate and reduce methane emissions and flaring. [www.texasmethaneflaringcoalition.org](http://www.texasmethaneflaringcoalition.org)

13 The AER is a successor to the Alberta Energy and Utilities Board (EUB).
assessing air quality issues and recommending management actions. The multi-stakeholder forum of CASA (Clean Air Strategic Alliance), established in 1994, is sponsored by the government of Alberta and helps to provide recommendations on policy and regulation related to air quality. Although the forum has no legislative authority, it works hand in hand with the AER, and actually initiated teams to make recommendations on gas flaring and venting management in 1998 and 2002.

The EUB used CASA’s recommendations from 1998 and established a gas flaring reduction target for Alberta for 2001, which aimed at reducing flaring by 25% of the volume flared in 1996. By 2000 the actual reductions were more than double the target. In 2002, the EUB set a limit of 670 million cubic meters of gas flared in the year, and established that, if the limit was not met, the EUB would limit solution gas flaring at individual operating sites based on the analysis of the most current annual data from each facility. With a limit set, and a firm target reduction of 50%, solution gas flaring in Alberta was actually reduced by 62% in 2002.[166]

Since its formation, the AER has issued directives that require upstream oil and gas operators to reduce methane emissions from upstream oil and gas sites by 45% from 2014 levels by 2025. Most of the requirements have been developed in consultation with CASA. Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting[167] contains the requirements for flaring, incinerating and venting at all upstream petroleum industry wells and facilities. The requirements adopt CASA’s objective hierarchy and its framework for managing routine solution gas flares (see Figure 25 and www.casahome.org) and has extended its application of the hierarchy to include flaring, incineration and venting of gas in general.

Figure 25 Alberta Directive 060 gas flaring/venting management framework[167]
United Kingdom:
The Oil & Gas Authority (OGA)\(^{168}\) is the regulator for flaring and venting under the Energy Act 1976 (as amended by the Energy Act 2016) and the Petroleum Act 1998. This legislation requires operators to have OGA-issued consents in place for the flaring and venting of hydrocarbons during production operations. The objective of the OGA flaring and venting regime for offshore operations (where most production occurs in the UK) is to eliminate any unnecessary or wasteful flaring and venting of gas, throughout the life cycle of a petroleum installation and relevant facilities such as terminals. Under model clauses used in offshore licenses, operators are required to demonstrate that all reasonable steps have been taken to keep flaring and venting to a minimum during operations, and that due consideration has been given to the application of appropriate technology and alternative uses for the gas. The OGA recognizes that some flaring and venting is unavoidable, but requires that these are kept to a technically and economically justified minimum. Operators are required to apply for OGA consent to flare and/or vent gas emitted from their installations.

Before the UK left the EU (via the ‘Brexit’ process) in January 2020, certain offshore operations were also covered under the EU Emissions Trading System (ETS), a cap-and-trade system for GHG emission reductions. However, under the OGA and EU ETS, reductions in gas flaring from offshore operations stalled between 2015 and 2019\(^{169}\). The OGA has noted that flaring alone makes up a quarter of all UK offshore oil and gas production-related CO\(_2\) emissions\(^{170}\). Post-Brexit flaring-related emissions reductions will depend, in part, on the details of the new UK ETS and if/how it will link with the EU ETS. The OGA is exploring more stringent measures to eliminate unnecessary flaring and venting, and intends to integrate net zero considerations into its work, together with benchmarking of flaring and venting data, to drive improved performance across the industry.

Norway:
Routine flaring was banned in Norway in 1971. Emissions from flaring have continued to decrease, not only due to technology improvements but also as a result of incentives that have been created to encourage emissions reductions. Annual flare gas permits, which limit flaring volumes, must be obtained from the regulator. Oil and gas developers are required to make gas utilization plans prior to any field development. These plans are facilitated by the extensive gas pipeline network which can quickly, and at low cost, tie in associated gas from new developments. Nearly all of the gas that is produced is used for production purposes, reinjected or sold (mainly exported).

In 1991 the Norwegian government introduced a tax on CO\(_2\) emissions from offshore platforms, including gas flaring. The tax is assessed on the volume of gas flared, the volume of natural gas vented, and CO\(_2\) separated from petroleum and vented on platforms or other installations used for production or transportation of petroleum\(^{171}\). The tax rate, as of January 2021, is Norwegian Kroner (NOK) 800 or USD 94 per tonne of CO\(_2\) emitted. The government plans to increase the cost of CO\(_2\) emissions per tonne to a ceiling of NOK 2,000 or USD 235 by 2030\(^{172}\).

EU Fuel Quality Directive:
In addition to the country-level information discussed above, the EU Fuel Quality Directive, which is designed to reduce full life-cycle emissions for transport fuels, is seen as a further incentive to reduce the flaring-related GHG footprint of upstream activities. Further discussion is included in Annex X.

South and Central America:

Ecuador:
The country has made progress on reducing flare volumes at its state oil company, Petroamazonas, through a program started in 2009 called Optimization of Electricity Generation and Energy Efficiency (OGE&EE). This program was mainly focused on reducing flare volumes in order to monetize the associated gases. Before the program began, Petroamazonas flared an average of 100 million cubic feet of gas per day. Implementation of the OGE&EE, although challenging due the range of gas volumes and compositions at the site, has achieved success, allowing the company to avoid flaring more than 26 bcf of natural gas by 2018.

Following the reduction in flare volume, mobile generators were brought in to capture the gas so that it could be used as fuel, enabling the company to reduce its use of diesel and crude oil for generating power at its operations. This allowed the company to avoid using 647 million gallons of diesel between 2009 and 2019. In the second implementation phase of the project, the company connected its oilfield facilities to the national grid, which allowed it to...
access other sources of power. In 2018, 11% of the company’s power was generated from hydroelectric sources, compared to 0% in 2009.[173]

- **Brazil**: The National Agency of Petroleum, Natural Gas and Biofuels (ANP) in Brazil is the regulatory body responsible for regulating natural gas flaring and venting. Resolution No. 806/2020 of the ANP establishes new procedures for the control and reduction of flaring, and losses of oil and natural gas in exploration and production activities. Among several new provisions is a requirement that the ANP shall annually approve the forecasts for flaring and associated natural gas losses.

  Petrobras is Latin America’s largest national oil company in terms of oil production. In a sustainability report released in 2018, Petrobras outlined a plan to reduce GHG emissions, which included pledging zero year-to-year growth of its operational emissions by 2025 compared to 2015 figures. The company also pledged to allocate USD 500 million to GHG mitigation projects between 2019 and 2023. In the most recent sustainability report, Petrobras will seek to decrease carbon intensity in its operations to address Scope 1 emissions by reducing gas flaring, improving efficiency in thermoelectric plants, reinjecting CO2 in its pre-salt fields, and developing pilot projects for renewable energy generation.

  By reducing flaring and increasing its use of natural gas, Petrobras has achieved a significant reduction in methane emissions. Flaring was cut by 74% between 2009 and 2015. As oil production continues to grow in the pre-salt areas, Petrobras will seek to monetize the associated gas and avoid flaring. In its refining sector, Petrobras has implemented improved leak management systems and detection methods to improve flaring management. The company has also joined the World Bank’s ‘Zero Routine Flaring by 2030’ initiative, and is currently on track to meet the initiative’s objectives.[173]

- **Africa**

  - **Nigeria**: a comprehensive approach is taken to address associated gas flaring in Nigeria through the Nigerian Gas Flare Commercialisation Programme (NGFCP). Launched in 2016, the NGFCP envisioned achieving its target for eliminating flaring across more than 170 flare sites by 2020. It aimed to accomplish this through a strategy that provided a commercial approach to the elimination of routine gas flares while driving positive social, environmental and economic impacts in the Niger Delta, by mobilizing private sector capital towards flare gas capture projects. Also, the government has provided preferential treatment to gas producers over oil by providing fiscal incentives. Through lower taxes and royalties, Nigeria has helped to develop positive incentives to produce gas and develop downstream gas networks and markets.[174]

    Like Norway, Nigeria has also implemented a tax on gas that is flared. Under the ‘Flare Gas (Prevention of Waste and Pollution) Regulations’ of 2018, an operator that produces 10,000 or more barrels of oil per day must pay the government USD 2 for each 1,000 scf (28.317 cubic meters) of gas that is flared, regardless of whether the flaring is routine or non-routine. A small facility must pay USD 0.50 for every 28.317 cubic meters of methane flared.[175]

    The NGFCP focuses on technically and commercially sustainable gas projects developed by third-party investors who are invited to participate in a bid process. The bid process works by allowing these investors to bid on gas that would normally be flared, and the cost of the gas is defined by the highest bidder. The value put on the gas that would normally be flared creates an incentive for companies to capture the gas.[176]

    - **Algeria**: the Algerian government has prohibited the flaring of gas since 1966. Enforcement of the prohibition began with the 2005 Hydrocarbon Law. A 2006 Ordinance maintained the prohibition but allowed authorization for limited periods of flaring at an operator’s request, which had to be granted by the National Agency for the Valorization of Hydrocarbon Reserves (ALNAFT). The combined effect was a significant reduction in flaring through 2012. Since then, however, flaring has been on an upward trend, suggesting that enforcement of the strong legal framework is challenged.
Contributing to this are: (1) a lack of investment in adequate infrastructure, which is hampered by a combination of fuel subsidies and low oil prices; (2) aging oilfields generating more associated gas; and (3) the lack of foreign investment.[177]

ALNAFT is the primary regulatory agency in the oil and gas sector, and has the responsibilities for gas flaring matters. ALNAFT can grant temporary authorization for flaring in certain circumstances, including during well productivity assessments, at initial production wells, and during maintenance. An application must be prepared that includes a well location report providing the provisional date, duration and estimated volumes of gas to be flared. ALNAFT also has the responsibility for collecting penalties levied for flaring. If permitted to flare, a permittee is subject to a tax (20,000 dinars, or USD 150, per 1,000 normal cubic meters of gas flared in 2016). Flaring at new fields, which are typically operated by private companies, is prohibited; this appears to be strictly enforced, but the same may not be true for older fields operated by the Algerian NOC Sonatrach.[178] It is unclear whether any of these taxes had been paid.

The actions taken by the Algerian government resulted in a significant reduction in CO₂ emissions from flaring between 2009 and 2012. Since then, emissions have been on an upward trend, which can most probably be explained by the declining production at big oilfields where the GOR typically rises as the overall well pressure falls, and reinjected gas comes to the surface displacing some of the liquids being produced.[179]

Algeria is the largest gas producer in Africa. Oil and gas represents a significant portion of the country's GDP and almost all of its export revenues. To encourage gas utilization investments, Articles 88 and 91 of the Hydrocarbon Law provide special fiscal treatment such as investment tax credits or a reduced rate of corporate tax for LNG, LPG and electricity generation projects. The oil and gas infrastructure is well-developed and extensive. There has been recent progress in building additional infrastructure to facilitate more productive use of gas resources. In 2020, Eni and Sonatrach announced the completion of a 16-inch pipeline with the capacity to transport 7 million standard cubic meters of gas per day.

Australia

- Australia is one of the world’s largest LNG exporters. Flaring of gas is typically covered by the relevant petroleum and environmental regulations in each State and Territory. The legislation that regulates flaring differs between jurisdictions. For example, the Queensland Petroleum and Gas (Production and Safety) Act 2004[14] requires that gas should be used commercially or on lease wherever possible, and flared if such uses are not technically or economically feasible. In addition, venting of gas is only allowed if it is not possible for the gas to be flared, or if it would be unsafe to do so. Before the regulatory agency will authorize flaring or venting, the operator is required to provide evidence of the likely impact that the flaring and venting will have on the environment. This information would be similar to that which is typically required in an environmental impact assessment (EIA), which would need to be submitted as part of the flare permit or field development application process. The EIA has become a part of the regulatory approval procedures and helps to set the conditions under which flaring and venting are authorized. For example, the use of flares was authorized in the Gorgon Gas Development project, but restricted to: commissioning, start-up, venting, draining, purging, and heating and cooling of equipment and/or piping; process upsets; emergencies; and, for the BOG flare system, emergency operational releases from the low-pressure LNG storage and loading system, and excess pressure in the LNG tanks beyond the capacity of the BOG compressor/recycle compressor.[180]

Australia has also liberalized its gas markets, and encourages private participation and competition in gas supply. The regulatory institution is able to ensure that these pipeline operators are able to recover their investment costs through regulated transportation tariffs, and provides open access to pipeline networks for third parties. This sort of market liberalization has allowed the operator to market and sell the associated gas in the downstream market, which helps to improve the economics of associated gas and create opportunities for these operators to use the gas rather than flare or vent it.[181] According to the Australian Energy Market Commission, other than in the state of Victoria, pipelines operate on a

contract carriage basis, where trading is voluntary. Access to such pipelines is allocated on the basis of contracts between the pipeline operator and the pipeline user. The terms and conditions of access are negotiated, and pipeline users are able to trade their contracted pipeline capacity on a secondary market. The primary and secondary market for capacity enables market led investment in pipelines.15

Saudi Arabia

- In 2020, the gas market in Saudi Arabia was among the world’s largest. A significant factor contributing to its position was the government’s decision in the 1970s to begin diversifying the economy and reducing the use of oil as a domestic power source. The Master Gas System (MGS) was initiated to enable the capture of associated gas that would previously have been flared, and use the gas in the domestic power generation sector.

In 1975, Saudi Aramco began the work to design, develop and install a gas gathering, treating, processing and transmission system, which would collect gas from Saudi Aramco’s producing fields and take it to markets in the Kingdom. The MGS was unprecedented in scope, scale and cost, and became one of the most ambitious engineering projects undertaken in the region, requiring significant technology development. As new non-associated and unconventional gas fields were discovered, they were tied into the MGS for delivery to customers. By 1986 the MGS had been expanded to include offshore fields. System capacity reached 2 bcf/day and was supplying gas for power generation, NGL production and feedstock for petrochemical manufacturing, as well as supplying distribution networks for industrial, commercial and residential consumers. Plans include increasing the total capacity of the MGS network.

Since the inception of the MGS, Saudi Aramco has recovered close to 99% of the total gas produced, nearly eliminated the flaring of associated gas, and is removing approximately 100 million tonnes of CO₂e each year. Along with other initiatives, such as the Flaring Monitoring System used to monitor and mitigate flaring in real time, a methane LDAR program, the installation of numerous flare gas recovery systems, and enhanced equipment maintenance standards across its operations, Saudi Aramco aims to achieve zero routine flaring by 2030.

FLARING AND GAS PRODUCTION DATA MANAGEMENT SYSTEM

Compliance with legislation and regulations that address utilization or flaring of associated gas resources requires a system for the measurement, management and reporting of the produced and vented/flared gas. Such a process is generally referred to as a gas production data management system (GPDMS), and should:

- facilitate the collection and management of data from production facilities (preferably over the internet using standardized data exchange methods to populate a government-established template);
- provide tools for data consolidation and analysis to allow monitoring of progress against goals, and the preparation of summary reports; and
- assist in the identification and quantification of environmental impacts and potential opportunities to commercialize flared gas streams.

Some specific outcomes include:

- Maintaining an accurate inventory and accountability system for the production and utilization of hydrocarbon resources.
- Creating a baseline of associated gas production, flared volumes, gas consumption for productive use (non-flare) and flaring reductions by source.
- Tracking flaring reductions by source/geography/producing company.
- Linking with the national finance system to drive the collection of fees for flared gas (accounting for exemptions such as safety flaring).
- Creating a database that can support third-party funding of potential gas commercialization projects, including financing by multilateral development banks.

15 The Australian Energy Market Commission is the expert energy policy adviser to Australian governments, responsible for making the energy rules and providing advice. See https://www.aemc.gov.au/energy-system/gas/gas-markets
Important elements of a GPDMS are summarized below:

- All producers should use the GPDMS.
- Responsible agencies should establish the required frequency of reporting by production operators.
- A producer’s failure to report data accurately and timely is subject to enforcement and penalties.
- Producers should maintain a current inventory within the GPDMS of all locations where associated gas is produced, consumed, otherwise utilized, flared or vented.
- Producers should maintain, for a period specified by the responsible agency, daily logs, by source, of natural gas produced, consumed, otherwise utilized, flared and vented, and should maintain a daily log of each occurrence of gas flared or vented at its facilities.
- Key parameters for flaring logs are, for each flaring event: the date; time; duration; rates; volumes; and gas source or type.
- All data logs maintained by a producer should be available to an agency inspector at any time and be reconcilable with data reported into the GPDMS.
- For each source of associated gas that is flared or vented, producers report:
  - on a frequency specified by the responsible agency — the temperature, pressure, GOR and compositional analysis; and
  - annually — a 10-year forecast of gas production, with a reconciliation of actual volumes produced with the prior year’s forecast.
- All data reported into the GPDMS should conform to the standards and units specified by the responsible agency, including those for estimating volumes, measuring flow rates, and for calibrating flow measurement and gas testing equipment.

The GPDMS should be designed to support analysis and reporting, and should include the following:

- Validation of flared gas volume with gas production, in-field consumption by the producer, gas sold to third parties, gas converted to liquids and gas flared.
- Tools to perform data validation of actual and forecasted gas volumes reported versus oil production parameters and reservoir models.
- Analysis and consolidation of discrete sources of flared associated gas using geographic information system (GIS) tools.
- Demonstration of adherence to the ‘Zero Routine Flaring by 2030’ initiative, and other international commitments.
- The producer’s compliance with regulations and corresponding guidelines.
- Identification of opportunities to monetize associated gas still being flared.

**PROJECT ORIGINATION**

The work to create an effective institutional framework and the ministerial capacity to manage associated gas monetization projects bears rewards when flaring reduction opportunities are identified, projects are conceived, and in-field work is undertaken to bring gas that was formerly flared to a productive end use. The essential elements and work flow that facilitate these efforts are discussed below.

**Independent analysis of the potential for commercializing flared gas**

There are two independent sources of data upon which a flare gas commercialization strategy can be based: the volume of gas currently being flared; and the volume of gas reserves. The best approach to developing a baseline volume estimate combines both data sources.

Flared volumes can be obtained from top-down estimates, such as from satellites, or from bottom-up estimates, such as annual production reporting or meters on flared gas lines. Regarding satellite data, there are weaknesses due to the intermittent nature of the data capture, filtering routines to eliminate spurious data and reliance on difficult-to-corroborate correlations between captured data and flare volumes.
As for producer-reported data, weaknesses are introduced by lack of actual flow rate measurements, estimated data derived from GOR or other parameters, and accounting conventions that introduce systemic bias. Within a country’s borders, total gas reserves, including the portion that exists as associated gas, set the upper opportunity boundary for an overall program of gas utilization. On a field level, the quantity of associated gas establishes the potential scope for any particular project which aims to commercialize gas that is currently flared. A nation’s oil or energy ministry has access to country-level and field-by-field data that have been developed by the national oil company or by third-party producers operating in-country concessions. External sources of information (e.g. the IEA, US Energy Information Agency, BP (Statistical Review of World Energy), Wood Mackenzie, Rystad Energy) provide independent assessments of data to generate outlooks for reserves and production. When combined together, these data sources can be used to develop a robust and reliable country-level baseline perspective on associated gas utilization opportunities and potential reductions in flare-related GHG emissions.

Use of this baseline will enable the institutional entity charged with developing the framework for a country-level flaring reduction program to conduct its work. Within the context of national needs and SDG plans, assessments can be made of the positive environmental and gas savings effects of strategic themes (e.g. gas to power, LNG export, etc.). Identification of obvious gaps in critical infrastructure, institutional capacity or other enabling aspects can also occur. This information will enable remedial work to begin on the foundations needed to support the most promising options. These might include legal, economic or fiscal reforms, readiness assessments to secure and manage multilateral financial support, or major infrastructure work (e.g. roads, ports, electrical grid).

Studying the market for flare gas

The outcome from the baseline work is an opportunity horizon that shows the best thematic options for significant use of associated gas resources. It also indicates those options that are likely to face significant hurdles or that do not have sufficient scale to make a difference. However, the baseline work product generally does not provide sufficient information to enable an assessment of specific project concepts that lie on the opportunity horizon. More granular data would be needed for such an assessment.

Flare gas market studies for each of the high-potential gas utilization options should be conducted. The audience for such studies is the national government, in-country oil and gas producers, and prospective third-party project developers looking to obtain access to associated gas resources. As discussed in Section 1, the objective of the value chain feasibility studies is to characterize the source of the associated gas, its final disposition and each of the intermediate links along the chain. These comprehensive studies, which rely on field-level information and selected gas utilization technologies, determine the feasibility, attractiveness and sustainability of projects. Analyses include options for rates of gas utilization, capital expenditures, operating and maintenance costs, market demand and pricing for end products. Risk analyses and sensitivity studies are performed for each of the key parameters. The level of detail and specificity enables an evaluation of potential emission reductions, the potential scale of revenue and tax generation, contributions to GDP growth and an assessment of multiplier potential.

One option for performing market feasibility studies is for the national flaring reduction entity to work with a multilateral development bank (MDB) — see footnote 16 and the section on Third-party funding opportunities on page 94.

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16 A multilateral development bank (MDB) is an international financial institution chartered by two or more countries for the purpose of encouraging economic development in poorer nations. MDBs consist of member nations from developed and developing countries. Unlike commercial banks, MDBs do not seek to maximize profits for their shareholders. Instead, they prioritize development goals, such as ending extreme poverty and reducing economic inequality. They often lend at low or no interest or provide grants to fund projects in infrastructure, energy, education, environmental sustainability, and other areas that promote development.

See: https://www.investopedia.com/terms/m/multilateral_development_bank.asp
Due to their interest in fostering new development projects, MDBs are often willing to share their technical expertise on feasibility studies that can lead to development outcomes aligned with the SDGs. Having extensive experience with mature and new technologies, MDBs are willing to work on such studies even where other investors may be involved in project finance. For large gas utilization projects, the Global Infrastructure Facility (GIF)\(^\text{17}\) can support governments in bringing well-structured and bankable infrastructure projects to market. The GIF’s project support can cover design, preparation, structuring and transaction implementation activities. More details on the GIF can be found on page 95.

**Identification of project structures**

The primary objective of a producer of associated gas is crude oil production and sale. Consequently, the structure of any project to utilize associated gas will need to address the inherent uncertainties of gas volume and quality. Referring back to the discussion on the uncertainty in associated gas production (see Developing a utilization strategy on page 46), it is clear that there is a natural ordering of risk associated with its corresponding project structure (from simple to complex) as the extent of gas capture increases. Figure 26 illustrates the flare gas monetization concept which was developed by the GGFR team to support the utilization of flare gas in different countries. This approach bundles gas volumes into four tranches of riskiness:

- **Tranche 1:** This is the lowest risk, and any volumes are reserved for the producer (typically for reservoir pressure maintenance or small-scale electricity generators) to facilitate crude oil production.
- **Tranche 2:** The producer may offer this tranche (with certain volume guarantees) to flare-gas project developers.
- **Tranche 3:** With the proper risk/reward structure — containing more sophisticated volume risk mitigation instruments and government guarantees — developers may be incentivized to pursue development projects.
- **Tranche 4:** With the highest degree of volume risk, it is difficult to support profit-generating projects without creative business models and technological solutions.

Figure 26 Risk tranches for associated gas volumes\(^\text{182}\)
There are four general models for associated gas utilization projects, as shown in Table 13. Of these, Types A and C are considered to be more straightforward from a project structuring perspective. Only the oil production operator (as the gas supplier), the gas buyer and, perhaps, a third party (as the provider of technology or as a standalone project operator) would come together to frame the venture. In some cases, the NOC, as the resource owner, may also be involved. The government, acting through various ministries, would have a limited role — such as issuing permits, determining applicable regulations, and collecting taxes. In most cases, the contractual provisions can be handled as an addendum to the original oil production agreement. Types B and D have more involved structures because of the involvement of third-party investors, financiers or providers of proprietary technology or services. Type D projects are the most complex.

Table 13 General models for associated gas utilization projects

<table>
<thead>
<tr>
<th>TYPE</th>
<th>INVESTOR IN GAS UTILIZATION PROJECT</th>
<th>TYPICAL SUPPLY AND USE SCENARIOS</th>
<th>COMMENTS</th>
</tr>
</thead>
</table>
| A    | The operator is the sole investor in the gas utilization project | Source: Tranche 1. The operator uses gas in its own operations. | Own use/own investment.  
- The field operator plans, implements and operates the flare reduction program. |
| B    | A third party (usually just one) invests directly in the utilization project or provides proprietary technology or services | Source: Tranche 1 or Tranche 1 and 2. The operator uses gas, or gas-derived product (e.g. CNG, LNG, electricity) in its own operations. | Own use/on-site conversion.  
A third party invests in, or owns/operates, the technology/facilities that consume the gas, and the field operator and third party enter into an:  
- energy conversion agreement;  
- equipment lease agreement; or  
- build-own-operate (BOO) or other transitional agreement. |
| C    | The operator is the sole investor in the gas utilization project | Source: Tranches 1 and 2 or Tranches 1, 2 and 3. The gas or gas-derived product is sold to a customer. | Flare gas to market by field operator.  
- The entire value chain from source to customers is owned and operated by the field operator. |
| D    | One or more third parties (often, there are multiple entities) invest directly, provide financing, or provide technology or services | Source: any combination of Tranches 2, 3 and 4. The gas or gas-derived product is sold to an intermediary (e.g. a gas- or electricity-distribution company) or directly to an end user. | Flare gas to market by third party.  
Independent entities purchase the gas, add value and then sell the output to customers.  
- The operator may be a co-investor in the downstream value chain entities. |
A number of factors influence the choice of project structure, especially for Type D projects. Key factors include the following:

- **Legal regime and taxes:** The host country’s legal regime and local taxes often have a major impact on project structure. Regulations (e.g. local content requirements) and tax rates for the upstream sector may be different from the sector applicable to the associated gas project.
- **Governance:** A typical oil production operation receives oversight from the host national government through its oil ministry and day-to-day direction through an operating committee. For an associated gas project, the governance arrangement may need to be broadened to include local stakeholders, lenders and key customers.
- **Efficient use of project facilities:** The associated gas project structure should encourage efficient use of all project facilities, by the project owners and by third parties. The structure should encourage sharing of common facilities, open access for third parties to utilize spare capacity and reduction of unnecessary facilities and their related costs, thereby making the project more profitable for all stakeholders.
- **Flexibility in ownership:** There may be a desire by the government, other local stakeholders, and lenders to have a direct ownership interest in all, or specified portions of, the project. The choice of a particular structure can enable different levels of ownership in the different components of the project.
- **Risk management:** All projects carry some risk. The more complex the technology, the greater the number of participants in the value chain, the more layered the financing, and the more untested the regulatory and fiscal structures are, the greater the risk to successful execution of the project. Each aspect can be managed (‘de-risked’) through contractual terms or financial instruments. Where a third party is involved in a venture, the decision drivers and thresholds may be different, as it may have a lower hurdle rate for investment than the oil producer, or a different perspective regarding risk.
- **Desire for limited recourse financing:** If the project intends to attract limited recourse project financing, a special purpose corporate entity will generally need to be set up as the finance partner.

- **Marketing arrangements:** The marketer of the final gas or derivative products can be different from the producer, depending on the project structure.
- **Transfer price:** The transfer price is the price of gas sold by the upstream gas producer to the utilization project entity. Pricing is often a contentious issue, since the major sponsors of the utilization project must negotiate benefit sharing with the upstream gas producer. When the gas is moved from the upstream (production) to the downstream (e.g. LNG) sector, an ‘arm’s length’ price may be difficult to negotiate. Each segment of the gas value chain may fall under a different fiscal regime. The overall profit of the sponsor will be influenced by determining where the economic value is captured.

One other important consideration is the in-country gas distribution network or power grid readiness (e.g. physical infrastructure, such as transmission pipelines, grid management systems, and distribution networks), plus the management and administrative structures to support a major associated gas development project. Furthermore, the way in which markets are structured can have a significant effect on the likelihood and rate of implementation of any gas utilization project. The supply, wholesale, and retail market segments for natural gas and electricity can be structured as exclusive, competitive, or a hybrid with prices that are either regulated or market-based. Of critical importance in any energy market is a clear and dependable path through which end users pay for the gas or electricity received. The flow of energy from the gas developer through to the end user, and the flow of funds in the opposite direction, are the key features of any market and the critical facilitating features of any project.

Establishing a creditworthy buyer can also present challenges in some countries. Due to the lack of buyers with a pre-existing credit position who are able to support financing requirements, project developers and lenders may need to examine the value chain down to the source of the cash flow, i.e. the end user of the gas or power produced. This is especially important in the case of traditional take-or-pay contracts. Guarantees and third-party risk sharing can be essential for ensuring that the market is structured to support the project. Where the government plays an important role in catalyzing a project, development of standard templates for key commercial agreements can foster a more productive review by prospective project developers and financiers.
Table 14 highlights several agreements that come from the experience of the Nigerian Gas Flare Commercialisation Programme.

**Private sector participation framework**

Creating an enabling environment for private sector participation in an associated gas project should involve most of the government’s ministries, and should take into account the following:[184]

- Aligned and consistent policies on ease of doing business need to be put in place. This includes registration of new businesses and, for foreign investors, ease of capital repatriation.
- The country’s creditworthiness is a fundamental requirement in encouraging project finance, including attracting offshore financing interests. Availability of local financing enables more attractive structuring of deals and lowers attendant financing costs.
- Frameworks should enable the aligned and smoother implementation of infrastructure; these include right-of-way laws, sectoral regulations and arbitration processes.
- There should be a clear indication of the sectors in which the government seeks private participation. This should be communicated consistently from the onset of planning. Major changes in government policies will almost certainly impact private sector confidence and commitment.

Table 14  Key commercial agreements[184]

<table>
<thead>
<tr>
<th>TYPE</th>
<th>PARTIES</th>
<th>DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Milestone development agreement</td>
<td>• Flare gas buyer (project proponent)</td>
<td>The buyer commits to implement the project according to a set of milestones. Buyer performance is encouraged by a bond or other surety instrument.</td>
</tr>
<tr>
<td></td>
<td>• Government or producer</td>
<td></td>
</tr>
<tr>
<td>Gas supply agreement</td>
<td>• Flare gas buyer</td>
<td>Involves transfer of gas ownership from government (or resource owner/producer) to buyer; take-or-pay terms apply.</td>
</tr>
<tr>
<td></td>
<td>• Government or producer</td>
<td></td>
</tr>
<tr>
<td>Connection agreement</td>
<td>• Flare gas buyer</td>
<td>Delivery terms and conditions, rules for the physical connection of facilities, and nomination procedures apply.</td>
</tr>
<tr>
<td></td>
<td>• Producer (and/ or pipeline transporter)</td>
<td></td>
</tr>
<tr>
<td>Deliver or pay agreement</td>
<td>• Producer</td>
<td>The producer guarantees that a specified volume of gas will be delivered or a fee will be paid by the producer to the buyer.</td>
</tr>
<tr>
<td></td>
<td>• Flare gas buyer</td>
<td></td>
</tr>
</tbody>
</table>

Associated gas utilization projects that have significant scale and scope, where there are multiple investors, and for which external finance is necessary, can sometimes get stuck at the conception phase. Often this is due to the perceptions of investors and project owners that the risk is too high and the returns too low versus alternative uses of capital. An example of a high-level risk register is shown in Table 15 on page 92.
Proper structuring at the project development stage can facilitate success by addressing a project’s risks across a variety of dimensions, including feasibility, viability, financial security, liquidity and value generation. There are many financial tools, such as guarantee insurance, hedging, derivatives and swaps, risk tranche offloading, special purpose vehicles, etc. to help de-risk a project.

When the proponent (e.g. the production company, NOC, an independent venture entity or, in some cases, a responsible government ministry) starts to prepare the project description with the intent to attract private capital, it will need to decide on a risk-sharing protocol for the project. If it is perceived that the risks are not allocated appropriately, the project may not find investors and lenders, i.e. it does not pass the ‘bankability’ test. Designing an optimal risk-sharing protocol at the project development phase is the key to ensuring bankability. Two approaches, which are complementary to each other, can play an important role at this stage.¹⁸⁶

<table>
<thead>
<tr>
<th>TYPE OF RISK</th>
<th>RISK DESCRIPTION</th>
<th>RISK MITIGATION OPTIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market</td>
<td>Market demand, balance and competition</td>
<td>● End-use demand, competition and economic analyses</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Payment guarantees</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Verified credit rating of off-taker</td>
</tr>
<tr>
<td>Political/</td>
<td>Policy change, government stability, energy regulatory framework</td>
<td>● Engage government as a partner in financial and development negotiations</td>
</tr>
<tr>
<td>regulatory</td>
<td></td>
<td>● Political risk insurance</td>
</tr>
<tr>
<td>Development</td>
<td>Land rights and ownership, and delays and complications relating to completion</td>
<td>● Follow conventional, known and reliable development processes, leases, contracts and</td>
</tr>
<tr>
<td></td>
<td>of front-end engineering design (FEED) study, site and land access</td>
<td>other documentation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Maintain close coordination with regulatory authorities responsible for issuing</td>
</tr>
<tr>
<td></td>
<td></td>
<td>construction and operating authorizations</td>
</tr>
<tr>
<td>Financial</td>
<td>Creditworthiness of product (gas, gas-derived or power) off-takers, Capital for</td>
<td>● Manage financial actions through known, transparent international monetary vehicles</td>
</tr>
<tr>
<td></td>
<td>major facilities and other auxiliary investments</td>
<td>● Engage investors willing to support long-term sustainable programs</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Include loss limits or first-loss provision for events not under the control of the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>investor</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Sovereign guarantees, World Bank guarantees</td>
</tr>
<tr>
<td>Environmental</td>
<td>Natural disaster potential, endangered species, air and water quality emissions,</td>
<td>● Follow international environmental standards from the World Bank and ISO and main</td>
</tr>
<tr>
<td></td>
<td>proximity to populated areas</td>
<td>treaties to mitigate future environmental or regulatory issues</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Project preparation facility (PPF): Development bank PPFs are used to develop</td>
</tr>
<tr>
<td></td>
<td></td>
<td>bankable, investment-ready projects. Under PPFs, technical and/or financial support is</td>
</tr>
<tr>
<td></td>
<td></td>
<td>provided to project owners or concessionaires. This can include undertaking project</td>
</tr>
<tr>
<td></td>
<td></td>
<td>feasibility studies, developing procurement documents and project concessional agreements,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>undertaking social and environmental studies, and creating awareness among the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>stakeholders.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>● Market sounding: Through market sounding exercises, important feedback from the lender</td>
</tr>
<tr>
<td></td>
<td></td>
<td>community can contribute to the project preparation phase and shape the risk allocation</td>
</tr>
<tr>
<td></td>
<td></td>
<td>matrix in a market-acceptable manner. This can also include an assessment of the ability</td>
</tr>
<tr>
<td></td>
<td></td>
<td>and willingness of:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(a) associated gas producers to provide a guaranteed supply; (b) midstream value chain</td>
</tr>
<tr>
<td></td>
<td></td>
<td>participants to guarantee transportation of processing capacity; and (c) external</td>
</tr>
<tr>
<td></td>
<td></td>
<td>financiers to participate in one or more segments of the project.</td>
</tr>
</tbody>
</table>

Table 15  Associated gas project high-level risk register
A project that has a risk-sharing protocol based on broad-level, early feedback from the lending community will be more likely to raise the required funding with fewer complications.

**DEFINITION OF SPECIFIC PROJECTS**

In some countries, individual associated gas projects that are considered strategic are developed and operated by state oil companies. Examples of strategic projects are those where all gas resources are directed to one end use, such as export LNG, electricity grid transformation, seawater desalination, etc. In such cases, the process for defining and implementing the project is characterized by a screening, evaluation, and engineering design, procurement and construction process. Projects can take years to move from conception to start-up, and many other ministries can be involved in directing or executing portions of the project.

For most other (i.e. smaller) projects, the government’s role is typically one of oversight, and is limited to setting policies that define development objectives for the gas sector, establishing institutions that set priorities, creating legal and fiscal frameworks governing associated gas development, and monitoring governmental entities and private sector partners to ensure that the rules and priorities are followed. Typically, for these non-strategic projects, a matter of overriding concern for the delegated governmental authority will be how soon the gas can be diverted from flares and brought to market for productive use.

To enable the quick realization of benefits from its associated gas resources, the government should select appropriate flaring reduction/associated gas utilization projects based on relevant decision-making criteria and a transparent administrative process. It should develop a plan to promote the opportunities for associated gas monetization in order to attract qualified companies or consortia, and/or prompt additional investment by producers that are already active in the country. Aspects that should be addressed when communicating these opportunities include: the terms of reference for any bid or prequalification process; the model contract language; and the key decision criteria (see Table 16) that will be used to select winning project proposals. Not all aspects will be viewed from the same perspective by the project developer and the national government, hence it is important to obtain alignment where differences of opinion exist.

<table>
<thead>
<tr>
<th>FACTOR</th>
<th>IMPORTANCE TO GOVERNMENT</th>
<th>IMPORTANCE TO DEVELOPER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustainable demand for product(s)</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Time to start-up</td>
<td>High</td>
<td>Medium</td>
</tr>
<tr>
<td>Need for economic or fiscal support from the country</td>
<td>High</td>
<td>Medium</td>
</tr>
<tr>
<td>Profit generated for the national government</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Reduction in flared gas volume versus the national total</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Replicability to other flare sources in the country</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Infrastructure investment by the country (if needed)</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Contribution to progress on SDGs</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>GDP multiplier potential</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Technology risk/reliability</td>
<td>Medium</td>
<td>High</td>
</tr>
<tr>
<td>Rights of way/land acquisition requirements</td>
<td>Medium</td>
<td>High</td>
</tr>
<tr>
<td>Stakeholder acceptance</td>
<td>Medium</td>
<td>Medium</td>
</tr>
<tr>
<td>Profit generated for the developer</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Infrastructure investment by the developer (if needed)</td>
<td>Low/high*</td>
<td>High</td>
</tr>
</tbody>
</table>

* Dependent on the type of infrastructure
THIRD-PARTY FUNDING OPPORTUNITIES

Marrying the technological solution with the capital needed to construct the infrastructure and facilities is a critical step in any project that is designed to monetize associated gas that had previously been flared. The most expedient path is when the oil and gas producer can self-fund or self-finance the entirety of the project. However, this typically requires that the project: (a) meets the investment hurdle rates established by the company; (b) is required by law, regulation or an agreement with a host government; or (c) is driven by a company policy.

For those cases where the oil and gas producer cannot support an entire associated gas flaring reduction/monetization project, other (external) sources of finance will be required. Key among such funding sources are those that focus on ‘climate finance’, a broadly defined term that encompasses local, national or transnational financing that comes from public, private and alternative sources, and which seeks to support mitigation and adaptation actions that address climate change. In the two-year period from 2017–2018, annual climate finance flows reached USD 579 billion, representing an increase of USD 116 billion (25%) compared with the 2015–2016 period (see Figure 27). This rise in finance flows reflects increases in financing across nearly all types of investors.[187]

Not all external finance that falls under the umbrella of ‘climate finance’ is available to help support an associated gas monetization project. Some sources focus only on renewable energy projects. Others consider a broader portfolio of projects, but may still restrict or avoid investing in any initiative that involves fossil fuel assets, even where there is potential for significant GHG emissions reductions. The following sections describe the most likely sources of external assistance (including funding) for an associated gas monetization project—private equity funds, the GIF, and climate and concessional funds.

Private equity funds

Private equity (PE) is an investment class consisting of capital that is not listed on a public exchange. The private equity industry is comprised of institutional investors such as pension funds, and PE firms funded by accredited investors. Pension funds generally act as passive investors, whereas PE firms are often active investors, providing operational support to the management of the target company. Typically, PE firms have a higher risk tolerance (as compared to pension funds) and seek higher rates of return from their investments over shorter investment horizons of 4–7 years compared with other types of investors.
A typical role for PE investors in addressing flaring reduction opportunities is to provide capital for developers of new gas utilization technologies or service companies. Equity investments can provide benefits to a project owner by offsetting certain costs (for example the capital cost of equipment) and spreading the risk to other parties. Lease financing is another option for some flaring reduction/gas monetization projects. In this approach, the project developer leases all or part of the project assets to a private equity investor.

PE can also play a role in underwriting project finance for defined portions of large gas infrastructure or development projects such as compression and pipeline infrastructure, gas plants, LNG export terminals or other midstream/downstream ventures. Investors can also develop and own the flare reduction/gas monetization projects or provide portfolio equity and sell their equity shares over time. In such cases, it is not uncommon for PE to be part of a consortium of investors that includes other financial institutions, such as commercial banks.

**Global Infrastructure Facility (GIF)**

On a different end of the spectrum from PE funds lies the GIF — a global, open platform that facilitates the preparation and structuring of complex infrastructure public-private partnerships to enable the mobilization of private sector and institutional investor capital. The GIF does not fund projects directly. Instead, it works with client governments to support the development or enhancement of infrastructure assets. The projects are implemented primarily by privately-operated entities, or by public sector entities operating on a commercial basis. The key requirements for GIF involvement are that the project: (a) provides infrastructure as a public service; (b) has strong potential to achieve financial viability and sustainability; and (c) will attract long-term private capital.

The GIF platform (Figure 28) coordinates and integrates the efforts of MDBs, private sector investors and financiers, and governments interested in infrastructure investment in emerging markets and developing economies (EMDEs). The GIF helps to develop EMDE infrastructure as an asset class that is attractive to the full range of private investors seeking diversification into long-term assets in faster growing economies. This approach enables collaboration and collective action on complex projects that no single institution could achieve alone.\[188\]
The GIF’s project preparation and transaction support activities can include advisory support for client governments as needed through the following project stages:

- **Project definition and enablement** — preliminary work to prioritize investments and test a project concept through ‘pre-feasibility’ analysis, as well as support for legal, regulatory or institutional reforms as required to enable successful development and/or participation of long-term private capital in the financial structure of a particular project.

- **Project preparation and investment feasibility** — support for the full range of project preparation and appraisal activities required to bring the project to a point where the government is able to make an informed decision to proceed with a transaction.

- **Transaction design and implementation** — support in preparing transaction documentation and managing a competitive transaction process, including initial design of risk mitigation/credit enhancement packages.

- **Post-transaction and financing** — continued support provided to the client government as a project moves from commercial to financial close, including updates to pricing and fiscal analysis related to government contributions, as well as guidance on the selection of the most appropriate credit enhancements.

With regard to associated gas flaring reduction projects, the GIF’s project preparation and structuring activities have been approved for the feasibility analysis of a ‘virtual pipeline’ project in Ecuador that aims to capture, store and transport untreated gas from multiple oilfields to processing facilities using a network of specialized trucks. The gas is intended to be used for power generation or to produce natural gas-derived products.

**Climate and concessional funds**

Between PE funds and the GIF are many different organizations that exist to facilitate projects that generate positive climate outcomes. Fundamentally, they all exist to address the high cash flow demand/high-risk portion of a project’s life cycle noted in Figure 29.

Climate-focused finance flows in diverse ways. Funding originates from different public and/or private sources, flows through a variety of multilateral, bilateral and national public or private channels, and is invested in various ways (on commercial or concessional terms) to satisfy activity- and recipient-specific needs and circumstances.

*Figure 29 Variation in risk and cash flow over the typical project life cycle\(^{1}\)*
MDBs are international financial institutions chartered by two or more countries for the purpose of encouraging economic development in poorer nations. They consist of member nations from developed and developing countries. Unlike commercial banks, MDBs do not seek to maximize profits for their shareholders. Instead, they prioritize development goals, including climate-related outcomes, and promote development.

In 2019 MDBs reported a total of USD 46.6 billion in financial commitments to the mitigation of climate change. Investment loans are the most common financial instrument used by MDBs, often at low or no interest rates. The reduction of gas flaring in the oil and gas industry is an activity that is eligible for classification as climate mitigation finance under the Common Principles for Climate Mitigation Finance Tracking. Among the global climate funds, those that are categorized as multilateral climate funds (MCFs) include the Green Climate Fund (GCF); the Global Environment Facility (GEF), which has responsibility for several subsidiary funds, and the Clean Technology Fund (CTF), which is part of the Climate Investment Funds (CIF).

These MCFs provide the majority of dedicated climate finance for mitigation activities (see Table 17) to support the development and deployment of technologies in fast growing countries. The cumulative amount of total finance approved for mitigation from all climate funds was USD 10.4 billion as of December 2019. Like all MCFs, these funds, which are administered by the World Bank, typically work through blended finance instruments (see page 98) but also provide direct loans and grants.

The most common forms of climate finance provided by MCFs and MDBs are forms of concessional or ‘soft’ loans. These instruments are repayable loans provided on terms that are more favorable than those prevailing on the market, and include lower interest rates, longer terms, longer grace periods and reduced levels of collateral. Concessional loans of varying degree and type have been established as the main financing instruments through which bilateral and multilateral development banks provide support to public sector entities and local banks. In general, bilateral finance institutions and national finance institutions disburse a majority of their mitigation finance as concessional loans.

Table 17 The primary MCFs supporting climate mitigation (2003–2019, USD millions)[191]

<table>
<thead>
<tr>
<th>FUND</th>
<th>FOCUS</th>
<th>PLEDGED</th>
<th>APPROVED</th>
<th>NUMBER OF PROJECTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTF</td>
<td>Promotes scaled-up financing for demonstration, deployment and transfer of low-carbon technologies</td>
<td>5,404</td>
<td>5,205</td>
<td>137</td>
</tr>
<tr>
<td>GEF (funding cycles 4-7)</td>
<td>Focuses on developing countries or those with economies in transition to meet the objectives of the international environmental conventions and agreements</td>
<td>4,006</td>
<td>2,136</td>
<td>499</td>
</tr>
<tr>
<td>GCF</td>
<td>Focuses on developing and vulnerable countries, in particular least-developed countries, Small Island Developing States, and African States</td>
<td>10,319</td>
<td>2,114</td>
<td>32</td>
</tr>
</tbody>
</table>

Table 17 The primary MCFs supporting climate mitigation (2003–2019, USD millions)[191]
An increasingly important form of climate finance is known as blended finance (see Figure 30). In general, blended finance is a structuring approach that allows organizations with different objectives to invest alongside each other while achieving their own objectives (whether financial return, social impact, or a combination of both). In the context of addressing climate-related challenges and opportunities outlined as part of the SDGs, blended finance can leverage capital from public or philanthropic sources to increase private investment.

The blended finance approach addresses the main investment barriers for private sector investors in SDG-driven projects in developing and emerging markets, including high perceived and real risk, and poor returns for the risk relative to comparable investments. Through a blended finance arrangement, these barriers are overcome using financing structures developed by teams of finance experts, often sponsored by development banks or private institutions (foundations and NGOs), that match projects to investment capital. The majority of the required capital is supplied by private sector institutional investors (banks, insurers, asset managers, etc.) that seek profitable risk-adjusted returns.

The key to securing this large private (i.e. commercial) investment is linking it to capital (a much smaller amount) supplied by so-called concessionary investors. These consist of public development assistance institutions (MCFs and MDBs), foundations and philanthropic investors that are willing to accept a higher risk of loss, or to earn below-market rates of return. Their motivation in participating in such an arrangement is invaluable in terms of the public good (i.e. infrastructure) that is created, wherever it advances progress on one or more SDGs in a particular location.

Strategies, objectives and approaches to blended finance can vary greatly across providers of development finance, such as donor governments, development cooperation agencies, philanthropies and other stakeholders. The OECD’s Development Assistance Committee (DAC) has developed a set of blended finance principles to provide definition and to advance accepted quality standards to ensure that blended finance has the required impact.

A final note on climate finance concerns two relatively new instruments — green bonds and transition bonds — which are discussed in the section on Green/climate change financing opportunities on page 52. Both are evidence of the innovation under way in the marketplace as project developers, environmentalists and financiers are working on ways to achieve carbon emissions reductions with the right balance of risk and return. Standards for both types of bonds are being developed to improve transparency and allow alignment between bond issuers and investors.