## Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Note to Readers</td>
<td>4</td>
</tr>
<tr>
<td>Acknowledgments</td>
<td>5</td>
</tr>
<tr>
<td>Abbreviations and Acronyms</td>
<td>6</td>
</tr>
<tr>
<td>Units of Measure</td>
<td>8</td>
</tr>
<tr>
<td>Section Guide</td>
<td>10</td>
</tr>
<tr>
<td>Algeria</td>
<td>12</td>
</tr>
<tr>
<td>Angola</td>
<td>18</td>
</tr>
<tr>
<td>Argentina</td>
<td>24</td>
</tr>
<tr>
<td>Brazil</td>
<td>32</td>
</tr>
<tr>
<td>Canada: Federal</td>
<td>40</td>
</tr>
<tr>
<td>Canada: Alberta</td>
<td>48</td>
</tr>
<tr>
<td>Canada: British Columbia</td>
<td>55</td>
</tr>
<tr>
<td>Canada: Saskatchewan</td>
<td>61</td>
</tr>
<tr>
<td>Colombia</td>
<td>68</td>
</tr>
<tr>
<td>Ecuador</td>
<td>76</td>
</tr>
<tr>
<td>Egypt, Arab Republic of</td>
<td>82</td>
</tr>
<tr>
<td>Gabon</td>
<td>88</td>
</tr>
<tr>
<td>Indonesia</td>
<td>94</td>
</tr>
<tr>
<td>Kagalshatan</td>
<td>100</td>
</tr>
<tr>
<td>Libya</td>
<td>108</td>
</tr>
<tr>
<td>Malaysia</td>
<td>114</td>
</tr>
<tr>
<td>Mexico</td>
<td>120</td>
</tr>
<tr>
<td>Nigeria</td>
<td>128</td>
</tr>
<tr>
<td>Norway</td>
<td>136</td>
</tr>
<tr>
<td>Oman</td>
<td>142</td>
</tr>
<tr>
<td>Russian Federation</td>
<td>150</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>156</td>
</tr>
<tr>
<td>United States: Federal Offshore</td>
<td>166</td>
</tr>
<tr>
<td>United States: Federal Onshore</td>
<td>175</td>
</tr>
<tr>
<td>United States: Colorado</td>
<td>181</td>
</tr>
<tr>
<td>United States: North Dakota</td>
<td>186</td>
</tr>
<tr>
<td>United States: Texas</td>
<td>192</td>
</tr>
<tr>
<td>Venezuela, República Bolivariana de</td>
<td>198</td>
</tr>
<tr>
<td>Glossary</td>
<td>204</td>
</tr>
<tr>
<td>References</td>
<td>206</td>
</tr>
</tbody>
</table>
Notes to readers

This report is a product of the staff of the World Bank. The findings, interpretations, and conclusions expressed in this report do not necessarily reflect the views of the World Bank, the Executive Directors of the World Bank, or the governments they represent. The World Bank does not guarantee the accuracy of the data included in this work.

Flare data graphs shown in this report are based on global flaring data estimates of the Global Gas Flaring Reduction Partnership (GGFR) using satellite data from the Colorado School of Mines. This approach is applied globally in a consistent manner. Deviations from other sources, based on reported gas flaring volumes, are possible.

No investment, policy, or other type of decision should therefore be based on this material, without verifying the findings independently.

When referring to legislation, regulations, or presidential decrees, this report cites the first year of enactment in the first and all subsequent references. For example, if a law was initially enacted in 1996 but has been revised several times over the intervening years, it will be referred to as "Petroleum Law, 1996."

In jurisdictions where laws and regulation numbers end in the year of enactment, spelled out in full (for instance, 12345/1996), the year is not repeated as part of the reference.

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This document was edited by Steven B. Kennedy and designed by Mark Lindop.
### Abbreviations and Acronyms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
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<td>Agence Nationale pour la Valorisation des Ressources en Hydrocarbures (National Agency for Valuation of Hydrocarbon Resources), Algeria</td>
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<td>ANLG</td>
<td>Angola Liquified Natural Gas Project, Angola</td>
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<td>Agencia Nacional de Hidrocarburos (National Hydrocarbon Agency), Colombia</td>
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<td></td>
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<td>BSEE</td>
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<td>CASA</td>
<td>Clean Air Strategic Alliance</td>
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<td>CDM</td>
<td>Clean Development Mechanism</td>
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<td>CO₂</td>
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<td>Department of State Control in the Sphere of Hydrocarbons and Subsoil Use, Kazakhstan</td>
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<td>EGAS</td>
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<td>EGPC</td>
<td>Egypt General Petroleum Company</td>
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<td>EIA</td>
<td>environmental impact assessment</td>
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<td>EPA</td>
<td>Environmental Protection Agency, United States</td>
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<td>Kementerian Energi Dan Sumber Daya Mineral (Ministry of Energy and Mineral Resources), Indonesia</td>
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<td>ETS</td>
<td>emissions trading system</td>
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<td>EU</td>
<td>European Union</td>
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<td>EU Emissions Trading System</td>
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<td>Government Accountability Office, United States</td>
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<td>GDP</td>
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<td>LPG</td>
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<td>MEM</td>
<td>Ministry of Energy and Mineral Resources, Kazakhstan</td>
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<td>MER</td>
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<td>MER UK</td>
<td>Maximizing Economic Recovery of UK Petroleum Resources, United States</td>
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<td>MINEC</td>
<td>Ministerio de la Industria y de Energía (Ministry of Industry and Energy), Colombia and Brazil</td>
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<td>MPE</td>
<td>Ministry of Petroleum and Energy, Norway</td>
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<td>MPGHM</td>
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<td>MPM</td>
<td>Malaysia Petroleum Management</td>
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<td>NDAC</td>
<td>North Dakota Administrative Code</td>
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<td>NDIC</td>
<td>North Dakota Industrial Commission, United States</td>
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<td>NEOI</td>
<td>Canada’s National Emissions Dataset Initiative, Canada</td>
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<td>NEITI</td>
<td>Nigeria Extractives Industries Transparency Initiative</td>
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<td>NGFCP</td>
<td>Nigeria Gas Flare Commercialization Program</td>
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<td>NNPC</td>
<td>Nigerian National Petroleum Corporation</td>
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<td>NNPC Ltd</td>
<td>Nigerian National Petroleum Company Limited</td>
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<td>NOCORP</td>
<td>National Oil Corporation, Libya</td>
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<td>NPD</td>
<td>Norwegian Petroleum Directorate</td>
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<td>NSPS</td>
<td>New Source Performance Standards, United States</td>
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<td>NTL</td>
<td>Notice to Lessees, United States</td>
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<td>OCS</td>
<td>(Federal) Outer Continental Shelf, United States</td>
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<td>OGA</td>
<td>Oil and Gas Authority, United Kingdom</td>
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<td>OGOR</td>
<td>Oil and Gas Operations Report, United States</td>
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<td>ONRR</td>
<td>Office of Natural Resources Revenue, United States</td>
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<td>OPRED</td>
<td>Offshore Petroleum Regulator for Environment and Decommissioning, United Kingdom</td>
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<td>PAP</td>
<td>Programa Anual de Producción (Annual Production Program), Brazil</td>
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<td>PDO</td>
<td>Petroleum Development Oman</td>
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<td>Petróleos de Venezuela, S.A.</td>
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<td>Pemex</td>
<td>Petróleos Mexicanos (Mexican Petroleum)</td>
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<td>Petronas</td>
<td>Petrolam Nasional Berhad (National Petroleum Limited), Malaysia</td>
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<td>PPGUA</td>
<td>Petronas Procedures and Guidelines for Upstream Activities, Malaysia</td>
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<tr>
<td>PSC</td>
<td>production sharing contract</td>
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<td>RRC</td>
<td>Railroad Commission, United States</td>
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<td>SEMARNAT</td>
<td>Secretaria de Medio Ambiente y Recursos Naturales (Ministry of Environment and Natural Resources), Mexico</td>
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<td>SENER</td>
<td>Secretaria de Energía (Secretariat of Energy), Mexico</td>
<td></td>
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<tr>
<td>SIP</td>
<td>State Implementation Plan, United States</td>
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<tr>
<td>SKK Migas</td>
<td>Satuan Kerja Khusa Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi (Special Task Force for Upstream Oil and Gas Business Activities), Indonesia</td>
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<tr>
<td>Sonangol</td>
<td>Sociedad Nacional de Combustibles de Angola (Angola National Fuel Company)</td>
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<td>TCEQ</td>
<td>Texas Commission on Environmental Quality, United States</td>
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<td>UKCS</td>
<td>United Kingdom Continental Shelf</td>
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<td>UNFCCC</td>
<td>United Nations Framework Convention on Climate Change</td>
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<td>YPF</td>
<td>Yacimientos Petrolíferos Fiscales (Fiscal Oil Fields), Argentina</td>
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### Units of Measure

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<tr>
<td>bcf</td>
<td>billion cubic feet</td>
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<tr>
<td>bcm</td>
<td>billion cubic meters</td>
</tr>
<tr>
<td>cf</td>
<td>cubic feet</td>
</tr>
<tr>
<td>m³</td>
<td>cubic meter(s)</td>
</tr>
<tr>
<td>mcf</td>
<td>thousand cubic feet</td>
</tr>
<tr>
<td>mmBtu</td>
<td>million British thermal unit(s)</td>
</tr>
<tr>
<td>mmcf</td>
<td>million cubic feet</td>
</tr>
<tr>
<td>mmmscf</td>
<td>million standard cubic feet</td>
</tr>
<tr>
<td>mscf</td>
<td>thousand standard cubic feet</td>
</tr>
<tr>
<td>MW</td>
<td>megawatt(s)</td>
</tr>
<tr>
<td>tCO₂e</td>
<td>tonnes of carbon dioxide equivalent</td>
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Each section in this guide seeks to answer the questions indicated below. The questions are presented here for easy reference and not repeated in each country-specific case study.

Policy and Targets
Role of Reductions in Meeting Environmental and Economic Objectives
Is there a government policy, strategy, plan, or commitment that specifies the role of flaring and venting reductions in achieving the country’s environmental and economic objectives? This section starts with a presentation of recent data on gas flaring.

Targets and Limits
Are there targets, limits, or both on flaring and venting in either primary or secondary legislation at the national or subnational level?

Legal/Regulatory Framework and Contractual Rights
Primary and Secondary Legislation and Regulation
What are the relevant provisions within the legal and regulatory framework that establish the relevant key principles and bring them into effect, so that regulators can deal effectively with gas flaring and venting?

Legislative Jurisdictions
Is gas flaring and venting a matter of national or subnational (provincial or state) jurisdiction?

Associated Gas Ownership
Who owns associated gas? Is there a separate entity that owns associated gas that is flared or vented?

Regulatory Governance and Organization
Regulatory Authority
Who regulates gas flaring and venting?

Regulatory Mandates and Responsibilities
Are the responsibilities for regulating flaring and venting clearly defined? Are there overlapping or conflicting mandates (for example, both the Ministry of Petroleum and the Ministry of Environment are given overlapping oversight roles)?

Monitoring and Enforcement
Does the regulator have adequate monitoring and enforcement powers?

Licensing/Process Approval
Flaring or Venting without Prior Approval
Are there circumstances in which operators can flare or vent associated gas without prior regulatory approval? Are such cases clearly defined in the legislation?

Authorized Flaring or Venting
Aside from the circumstances in which operators can flare or vent associated gas without prior approval, what authorization is required to flare or vent?

Development Plans
Is a development plan for associated gas required as part of the overall field development approval for greenfield projects?

Economic Evaluation
Do regulations require companies to evaluate opportunities, including economic evaluation, to minimize gas flaring and venting?

Measurement and Reporting
Measurement and Reporting Requirements
Do regulations require measurement and reporting of gas flaring and venting? Are measurement and reporting procedures established in the regulations on monitoring and enforcing compliance?

Measurement Frequency and Methods
Is the frequency of volume measurement of associated gas production, flaring, and venting specified? Are the measurement methods (including acceptable levels of accuracy) and what is to be measured (gas composition) specified? What has been the experience with measurement and reporting of flaring and venting?

Engineering Estimates
Are engineering estimates accepted where metering is not practical, or measurement requirements cannot be met?

Record Keeping
Do regulations require operators to keep a log of the measured volume and analyzed composition of associated gas produced and associated gas flared? If so, at what frequency and for how long are the records required to be kept?

Data Compilation and Publishing
Does the regulator or any other government agency compile flaring and venting data submitted by operators and produce reports for public disclosure? How are the reports disclosed? What is the frequency of such report disclosure? What is the time lag between the end of the reporting period and public disclosure? How many such reports have been issued to date?

Fines, Penalties, and Sanctions
Monetary Penalties
Are monetary penalties or fees established in the primary or secondary legislation for flaring or venting? Under what circumstances are they charged? Are there exceptions? What is the procedure for the payment? What has been the experience with the payment of these fees? How much has gone unpaid, and are there consequences for late or no payment?

Nonmonetary Penalties
Are nonmonetary penalties established in the primary or secondary legislation, such as license revocation or other types of administrative sanctions? What is the procedure for imposing such penalties? Is there an appeal process, and if so, how does it work? What has been the experience with the imposition of nonmonetary penalties?

Enabling Framework
Performance Requirements
Are there performance requirements (such as standards or emission limits) for gas flaring and venting?

Fiscal and Emission Reduction Incentives
Does the fiscal regime include incentives to reduce emissions, such as a carbon tax on emissions? Is there a preferential treatment in the fiscal framework for associated gas utilization? What has been the experience with the fiscal incentives?

Use of Market-Based Principles
Does the regulatory framework provide for the use of market-based or other principles to reduce flaring and venting? What has been the experience with nonfiscal incentives for reducing flaring and venting?

Negotiated Agreements between the Public and the Private Sector
Are there public-private partnerships and negotiated agreements between the industry and the regulator for reducing flaring and venting?

Interplay with Midstream and Downstream Regulatory Framework
Are there deficiencies in the legal and regulatory framework of the midstream and downstream gas sectors that adversely affect flare and vent reduction?
Regulation of Gas Flaring and Venting: 28 Case Studies from around the World    May 2022

Algeria

8.16 billion cubic meters of gas flared in 2021
(total oil production 1,132 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th>Year</th>
<th>Change</th>
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<tbody>
<tr>
<td>2015-2021</td>
<td>-11%</td>
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<tr>
<td>2015-2020</td>
<td>2%</td>
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Change in Flare Gas Intensity**

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<tr>
<th>Year</th>
<th>Change</th>
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<tr>
<td>2015-2021</td>
<td>13%</td>
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<tr>
<td>2015-2020</td>
<td>30%</td>
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* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 1 Gas flaring volume and intensity in Algeria, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Algeria increased from 7.6 billion cubic meters (bcm) in 2012 to 8.2 bcm in 2021, and the flaring intensity in 2021 remained high after peaking in 2020 (figure 1). Over the same period oil production dropped by a quarter. Among the countries considered in this review, Algeria’s flaring intensity in 2021 was the third highest. There were 177 flare sites in the last flare count, conducted in 2019.

In September 2015, Algeria submitted its first National Determined Contribution (NDC) to the United Nations Framework Convention on Climate Change (UNFCCC). The NDC has an unconditional target of reducing greenhouse gas (GHG) emissions by 7 percent by 2030 from a business-as-usual scenario and a conditional reduction target of 22 percent. Among the planned actions is the reduction by 2030 of flared gas volumes to less than 1 percent, presumably of the total associated gas volume (and not of total natural gas) produced. In 2018, the national oil company, Sonatrach, endorsed the World Bank’s Zero Routine Flaring by 2030 initiative.

Algeria first prohibited gas flaring in 1966. Law No. 05-07, 2005, formalized the prohibition and empowered two new regulators to implement flaring and venting restrictions. Law No. 19-13, 2019, prohibits routine flaring and venting of natural gas, sets taxes on flared or vented volumes, and outlines the responsibilities of Algeria’s regulatory agencies.

In its 2017 annual report, Sonatrach stated its goal of reducing flaring to less than 1 percent of associated gas by 2021. Sonatrach is responsible for most of the flaring. It produces approximately 80 percent of oil and gas, mostly from older oil fields.

2. Targets and Limits

Law No. 19-13, 2019, prohibits flaring and venting except under certain conditions but does not specify any targets or limits. Implementing regulations for the law had not been published at the time of writing. Algeria’s NDC and Sonatrach have adopted a target of less than 1 percent of total associated gas to be flared by 2030.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Law No. 19-13, 2019 (see footnote 6) empowers two national regulators to deal with flaring and venting: the Hydrocarbon Regulation Authority (Autorité de Régulation de Hydrocarbures [ARH]) and the National Agency for Valuation of Hydrocarbon Resources (Agence Nationale pour la Valorisation des Ressources en Hydrocarbures [ALNAF]).

Executive Decree No. 08-312, 2008, details the conditions of environmental impact assessments (EIAs) in the hydrocarbons sector and the ARH’s role in monitoring and enforcing compliance with EIAs. EIAs must include measures to eliminate, reduce, or compensate environmental impacts from flaring or venting.

4. No Legislative Jurisdictions

The prohibition on flaring and venting is a national policy governed by national regulators. According to Article 44 of Law No. 19-13, 2019, the ARH consults with other ministries and provincial authorities.

Note: These data are shown in this report based on global flaring data estimated by the Global Gas Flaring Reduction Partnership (GGFR) using satellite data from the Colorado School of Mines. This approach is applied to all countries covered in this report in a consistent manner.


3 Launched in 2015, the World Bank’s Zero Routine Flaring by 2030 Initiative commits governments and oil companies to end routine flaring no later than 2030. By declaring support and officially endorsing the Initiative, governments, companies, and development institutions are sending a message that eliminating the routine flaring of gas is a significant and necessary step toward mitigating climate change and ensuring valuable natural resources are not wasted (World Bank n.d.). The initiative is managed by the Global Gas Reduction Partnership. https://www.worldbank.org/ environment/gas-reduction/zero-routine-flaring-by-2030 (accessed December 20, 2021).
Algeria

5. Associated Gas Ownership

All hydrocarbons are the property of the state until extracted. The Ministry of Energy and Mines (Ministère de l’Énergie et des Mines) allocates resource titles to ALNAFT so that the regulator can hold bidding rounds and award titles.

6. Regulatory Mandates and Responsibilities

According to Article 42 of Law No. 19-13, 2019, ALNAFT is primarily responsible for the efficient development of hydrocarbon resources via the assessment of resource and reserve potential, the design and management of bidding rounds, and the administration of various types of upstream contracts with Sonatrach and other operators. It is also responsible for issuing authorizations for flaring in upstream operations.

B. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

According to Article 159 of Law No. 19-13, 2019 (see footnote 6) flaring for safety does not require prior authorization. However, operators must provide a detailed report of the flare to the relevant regulatory agency within 10 days. The law does not define technical reasons for flaring for safety. However, Article 43 charges the ARH with developing regulations concerning industrial safety, well integrity, and prevention of risks to the health and safety of employees. At the time of writing, the ARH had not published relevant regulations for Law No. 19-13, 2019.

10. Authorized Flaring or Venting

Article 158 of Law No. 19-13, 2019, prohibits flaring and venting. Flaring is allowed under certain conditions, such as during well testing or in the absence of sufficient takeaway pipeline or processing capacity. Upstream flares require authorization from ALNAFT; midstream or downstream flares require authorization from the ARH. In exceptional situations, venting during pipeline activities may be allowed, but authorization from the ARH is required.

11. Development Plans

A development plan needs to be approved by ALNAFT, according to Law No. 19-13, 2019. There is no explicit requirement for this plan to include associated gas disposal, but the plan must cover all commercially exploitable hydrocarbons (Article 106). According to Article 107, the plan must also include measurement and delivery points for all extracted hydrocarbons and allow for production optimization throughout the life of the asset.

12. Economic Evaluation

No evidence regarding economic evaluations could be found in the sources consulted.

C. Measurement and Reporting

13. Measurement and Reporting Requirements

Flare volumes must be reported, because they are used to calculate flare taxes (see section 21 of this chapter). Taxes create an incentive for operators to measure or estimate their flare volumes as accurately as possible. Under Article 43 of Law No. 19-13, 2019 (see footnote 6), the ARH is required to develop technical standards and regulations. Article 6 contains a general requirement that producers apply international best practices and techniques in hydrocarbon activities to "prevent, reduce and manage risks" associated with these activities. At the time of writing, the ARH had not published any relevant regulations for Law No. 19-13, 2019.

14. Measurement Frequency and Methods

No evidence regarding specified measurement frequency and methods could be found in the sources consulted. However, there is a tax on flaring (see section 21 of this chapter). Flaring taxes are collected annually, this requires that annual flare volumes be reported, which in turn requires their measurement or estimation.

15. Engineering Estimates

Law No. 19-13, 2019 (see footnote 6) does not mention the estimation of flaring and venting volumes, but the ARH is responsible for developing technical regulations following international best practices. At the time of writing, the ARH had not published any relevant regulations for Law No. 19-13, 2019. No evidence of regulators having approved estimation methods could be found.
16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted. However, the existence of an annual flare declaration to the fiscal authority on flare taxes must include all gas sold to downstream users.

D. Fines, Penalties, and Sanctions

18. Monetary Penalties

Article 227 allows the ARH to assess a daily penalty of 100,000 Algerian dinars (about US$750 as of September 2021) for noncompliance with Law No. 19-13, 2019 (see section 7 of this chapter). However, implementing regulations had not been published at the time of writing.

21. Fiscal and Emission Reduction Incentives

According to Article 210 of Law No. 19-13, 2019, there is a tax on flared volumes. This tax is nonrefundable for the purposes of calculating other payments under the upstream fiscal regime. The tax is 12,000 Algerian dinars (about US$90 as of September 2021) per 1,000 cubic meters (m³). ALNAFT can adjust this tax at the beginning of every year based on the national inflation index. The tax increases by 50 percent if an operator flares without authorization (except for flares for safety reasons as stated in Article 1519) or flares greater than the volumes allowed in the authorization (Article 213).

According to Article 215, the tax is not due under the following conditions:
- during exploration activities or well testing
- during the start-up period, the duration of which is set by ALNAFT or ARH
- in the absence of capacity for gas recovery or takeaway (pipeline) infrastructure
- at facilities built before 2005.

Article 29 of Executive Decree 21-330, 2021 requires that annual declaration to the fiscal authority on flare taxes must include all information necessary for calculation of the tax. According to Article 30, ALNAFT and the ARH are required to provide the fiscal authority a report on each flaring operation. The report must include actual flared volumes.

22. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector

The El Merk Central Processing Facility can be considered a de facto public-private partnership. It was developed and is operated by Groupement Berline, a joint venture between Sonatrach and several private companies. Sharing this central facility reduces the infrastructure footprint of all operators and the unit cost of processing associated gas for each participating operator. ALNAFT and the ARH were created in 2005, but the phase-out of Sonatrach’s regulatory powers took several years to complete. The El Merk Central Processing Facility was conceptualized during the 2000s and the contract awarded in early 2009.

Several other projects processing hydrocarbons from oil fields, including associated gas, were developed or expanded in the 2010s; others are still under consideration. By law, ALNAFT is responsible for the efficient development of hydrocarbon resources and the approval of field development plans. ALNAFT issues the necessary licenses, but guidance from the Ministry of Energy and Mines and Sonatrach helps determine the list of projects pursued.

24. Interplay with Midstream and Downstream Regulatory Framework

Article 67 of Law No. 19-13, 2019, requires both participation contracts and PSCs to include a joint marketing clause for natural gas to be exported. Sonatrach may market the gas on behalf of the partners if all parties agree. Article 121 states that serving the national market is a priority. Partners’ share of gas, or a portion of it, is transferred to Sonatrach if ALNAFT—in consultation with Sonatrach and the Electricity and Gas Regulatory Commission (Commission de Régulation de l’Electricité et du Gaz), which is responsible for forecasting demand—decides that these volumes are necessary to serve the national market (Article 123).

Article 131 grants open access to the gas transmission pipeline infrastructure. The ARH sets the tariff. Article 146 allows gas prices to be negotiated by the sellers (Sonatrach or its upstream partners) and the buyers for volumes above the national needs, as determined by the Ministry of Energy and Mines. The ARH sets the price of gas sold to power plants and distribution companies.

It must cover costs and fiscal and other charges and provide a reasonable rate of return (Article 147).

Gas prices in the domestic market are heavily subsidized. Domestic gas demand increased from about 25 bcm in 2010 to about 45 bcm in 2019, driven largely by subsidized pricing. The government has been pursuing a gasification strategy. There are programs to convert light-duty vehicles to liquefied petroleum gas (LPG) and buses and trucks to compressed natural gas (CNG) to reduce the consumption of oil products. Still, most of the demand growth reflects increased power generation and distributed generation in cities. Phasing out energy subsidies is seen as necessary to avoid a demand-supply imbalance and encourage further development of nonassociated gas fields.

All pipelines are developed and operated by Sonatrach under concessions granted by the Ministry of Energy and Mines (Article 127). Sonatrach delivers gas to liquefied natural gas (LNG), petrochemical and fertilizer plants, and refineries. A state-owned company, Sonelgaz, builds and operates distribution networks and serves other gas consumers. This dependence on state-owned entities for transmission and distribution networks can handicap the timely development of new pipeline capacity during periods of budget constraints, especially with subsidized end-user prices.
Angola

1.80 billion cubic meters of gas flared in 2021
(total oil production 1.123 thousand barrels per day)

Change in Flare Gas Volumes*

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Change in Flare Gas Intensity**

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<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>%change</td>
<td>-31%</td>
<td>-36%</td>
</tr>
</tbody>
</table>

* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 2 Gas flaring volume and intensity in Angola, 2012–21

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A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Angola increased from 3.2 bcm in 2012 to 4.5 bcm in 2016 before falling to 1.8 bcm in 2021 (figure 2). Oil production increased slightly in 2015 and has been falling steadily every year since. The flaring intensity was 12 percent lower in 2021 than in 2012. There were 48 individual flare sites in the last flare count, conducted in 2019.

In 2016, Angola endorsed the World Bank’s Zero Routine Flaring by 2020 initiative (see footnote 3). In mid-2021, it submitted an updated NDC to the UNFCCC and committed to an unconditional reduction in GHG emissions from the business-as-usual scenario of up to 14 percent by 2025.* Emissions under the business-as-usual scenario are projected to be 108.5 million tons of carbon dioxide equivalent (tCO₂e) in 2025. The conditional commitment is another 10 percent reduction by 2025. Base year (2015) emissions were 100 million tCO₂e. Flare reductions account for two-fifths of unconditional and one-third of conditional commitments. However, the target reductions in gas flaring are seemingly based on old data, from a period in which Angola’s oil production was much higher. The flaring intensity was 12 percent lower in 2021 than in 2012. There were 48 individual flare sites in the last flare count, conducted in 2019.

In 2018, as a result of a 2017 Presidential Task Force, the government of Angola responded to lower oil prices with legal reforms. Law 10/2004, Petroleum Law (Petroleum Law, 2004 hereafter),16 as amended by Law 5/2019, repealed Law 13/1978, General Law on Petroleum Activities. This law sets forth the general framework applicable to oil operations in Angola. It governs activities related to prospection, concession, search, assessment, development, and decommissioning. Law 13/2004, the Taxation of Petroleum Activities Law,17 as amended by Law 6/2019, defines the fiscal regime applicable to oil and gas activities. Law 26/2012, the Law on the Transportation and Storage of Crude Oil and Natural Gas, establishes the legal framework for downstream operations—namely, the transportation and storage activities of crude oil and natural gas.

In 2019, the Angola’s Nationally Determined Contributions are set forth in Governo de Angola (2021), which define the role of reductions in gas flaring. 16 Emissions under the business-as-usual scenario are projected to be 108.5 million tons of carbon dioxide equivalent (tCO₂e) in 2025. The conditional commitment is another 10 percent reduction by 2025. Base year (2015) emissions were 100 million tCO₂e. Flare reductions account for two-fifths of unconditional and one-third of conditional commitments. However, the target reductions in gas flaring are seemingly based on old data, from a period in which Angola’s oil production was much higher. The flaring intensity was 12 percent lower in 2021 than in 2012. There were 48 individual flare sites in the last flare count, conducted in 2019.

Most of Angola’s natural gas production is associated with oil produced in the offshore fields off the coast of Cabinda and the deep-water fields in the Lower Congo Basin. Historically, the majority of natural gas extracted has been reinjected in oil fields to enhance oil recovery or flared. In 2011, re-injection and flaring still accounted for 91 percent of all the natural gas produced in the country. The gas utilization policy focused on developing the country’s first LNG facility, in Soyo. Although the first LNG cargo was exported in 2013, exports remained low until 2017 but increased nearly 10-fold by 2020.

2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted. However, there is a de facto zero-flare policy for all new fields.

B. Legal, Regulatory Framework, and Contractual rights

3. Primary and Secondary Legislation and Regulation

In 2018, as a result of a 2017 Presidential Task Force, the government of Angola responded to lower oil prices with legal reforms. Law 10/2004, Petroleum Law (Petroleum Law, 2004 hereafter),16 as amended by Law 5/2019, repealed Law 13/1978, General Law on Petroleum Activities. This law sets forth the general framework applicable to oil operations in Angola. It governs activities related to prospection, concession, search, assessment, development, and decommissioning. Law 13/2004, the Taxation of Petroleum Activities Law,17 as amended by Law 6/2019, defines the fiscal regime applicable to oil and gas activities. Law 26/2012, the Law on the Transportation and Storage of Crude Oil and Natural Gas, establishes the legal framework for downstream operations—namely, the transportation and storage activities of crude oil and natural gas.

Decree 1/2009, Regulation on Petroleum Operations,18 defines and establishes the conditions and procedures to be observed in upstream oil and gas activities. Decree 7/2018 and Law 8/2018 are the first pieces of legislation enacted to regulate natural gas operations and provides more attractive tax rates for small producers. Operators of associated gas fields can re-inject gas to maximize oil recovery, commercialize the surplus, or transfer it to the Angolan LNG plant.

Law 5/1998, the General Environment Law,19 provides the framework for environmental legislation and regulation. Executive Decree

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Angola

97/2014 enacted the Regulations on Management of Operational Discharges. Decree 39/2000 concerns environmental protection in the oil industry and enacts environmental protection regulations for oil and gas activities. Contractors must prepare and submit an EIA to the Ministry for Mineral Resources, Petroleum, and Gas (Ministério dos Recursos Minerais, Petróleo e Gás [MMRPG]) for approval before starting any petroleum activities. The assessment needs to identify predictable environmental damages caused by the proposed petroleum activities and outline the necessary measures to decrease said damages.

4. Legislative Jurisdictions

Gas flaring and venting are matters of national jurisdiction.

5. Associated Gas Ownership

Angola's 2010 Constitution vests all resources in the soil and subsoil, territorial waters, exclusive economic zone, and continental shelf in the Angolan state. The Petroleum Law, 2004, prescribes that all petroleum deposits are an integral part of the state’s public domain, including all onshore and offshore petroleum reserves.

The most common type of association agreement with the national oil company, the Angola National Fuel Company (Sonangol), is for joint development of petroleum reserves.

6. Regulatory Authority

The MMRPG, created in 1978, oversees petroleum activities. It focuses mainly on coordination and cooperation with other entities. Its statute is provided under Presidential Decree 12/2018 as amended by Presidential Decree 15/2020. Other ministries, such as the Ministry of Environment and the Ministry of Finance, also have some degree of oversight and regulatory powers.

Law 5/2019 created a new regulator, the National Oil, Gas and Biofuels Agency (Agência Nacional de Petróleo, Gás e Biocombustíveis). Presidential Decree 49/2019 provides the organic statute of this regulator, which took over from Sonangol as the exclusive holder of mineral rights for oil and gas exploration and production. Law 5/2019 granted Sonangol preferential acquisition and operational rights in oil and gas concessions and operations.

7. Regulatory Mandates and Responsibilities

The primary role of the National Oil, Gas and Biofuels Agency’s, subject to the ministry’s supervision, is to regulate, supervise, and promote the execution of petroleum activities—namely, the exploration, exploitation, development, and production of minerals, crude oil and gas; refining and petrochemicals and the storage, distribution, and marketing of mineral and oil products. Article 7 of the Petroleum Law, 2004, stipulates that oil and gas operations shall be conducted prudently and consider the safety of persons and facilities as well as the protection of the environment and the conservation of nature. Article 24 requires licensees to take the precautions necessary to protect the environment in carrying out their activities. The applicable laws require environmental plans, including environmental impact studies and management and environmental auditing plans.

8. Monitoring and Enforcement

Article 41 of the Regulation on Petroleum Operations, 2009 (see footnote 19) describes the regulator's inspection functions. Article 42 describes the inspector’s rights. Article 49 on competence states that the MMRPG is responsible for monitoring compliance with the regulations.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 73 of the Petroleum Law, 2004, expressly forbids natural gas flaring except for short periods for testing or other operating reasons, which require special permission from the MMRPG.

10. Authorized Flaring or Venting

Article 73 of the Petroleum Law, 2004, states that when gas flaring is authorized, the supervising authority may determine that a relevant fee be charged in accordance with the quantity and quality of the gas flared and its location. No evidence could be found in the sources consulted on enforcement of such a fee. In the case of marginal or small deposits, the MMRPG may authorize the flaring of associated gas to make its exploitation viable. Flaring authorities may be granted only upon submission of an EIA.

11. Development Plans

Article 73 of the Petroleum Law, 2004, states that the development plans for petroleum deposits should always be formulated in such a way as to allow for the use, preservation, or commercial exploitation of associated gas. Article 22 of the Regulation on Petroleum Operations, 2009 (see footnote 19) states that the general development and production plan must include a plan for utilizing the associated natural gas. Article 23 states that annual production plans must include a provision for flaring and venting of natural gas and estimated volumes of special fluids to be injected for enhanced recovery.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Metering and recording practices have to follow methods and use instruments certified under the legal standards in force and in compliance with good technical standards. Article 34 of the Regulation on Petroleum Operations, 2009 (see footnote 19) states that operators must propose to the MMRPG the measurement system, equipment, and procedures for measuring oil and gas production and sales. Article 39 lists the gas measurement system components; Article 40 describes the requirements for measurement facilities. Article 24 requires operators to submit a report providing information on all activities related to natural gas by December 30 of each year. Article 44 requires the quarterly submission to the MMRPG of a report on the systems for measuring, testing, and calibrating the equipment. The reports must include information related to daily production and respective shipments.

For PSCs, contractors are required to record the monthly quantities of crude oil, natural gas, and water produced from each development area. These data must be sent to Sonangol within 30 days of the end of the month reported on.

14. Measurement Frequency and Methods

All petroleum extracted and recovered shall be metered and recorded daily. Article 34 on oil and gas measurement in the Regulation on Petroleum Operations, 2009, states that the operator must propose to the MMRPG the laboratory analysis methods required to determine all physical and chemical parameters. Article 45, on allowable tolerances, states that the maximum permissible error for gas meters must not exceed 0.1 percent of the measured volume. Sonangol and its partners do not systematically measure and report gas flaring figures.

15. Engineering Estimates

No evidence of engineering estimates could be found in the sources consulted.
Angola

16. Record Keeping
For PSCs, contractors must make available for examination daily or weekly statistics and reports regarding a contract area’s production at a time convenient to authorized representatives of Sonangol. Contractors must prepare and, at all times while a contract is in force, maintain accurate and current records of all activities and operations and keep all information of a technical, economic, accounting, or any other nature related to the conduct of petroleum operations.

17. Data Compilation and Publishing
No evidence regarding data compilation and publishing could be found in the sources consulted.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
Article 51 on fines in the Regulation on Petroleum Operations, 2009 (see footnote 19) includes provisions on applicable monetary fines. If a monetary correction is needed, the penalty must be assessed under the terms of the Tax Correction Unit in force.

19. Nonmonetary Penalties
No evidence regarding nonmonetary penalties could be found in the sources consulted.

G. Enabling Framework

20. Performance Requirements
No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives
The Angola Liquefied Natural Gas Project (ALNG) is the first LNG project in Angola. It uses associated natural gas, helping to reduce gas flaring and associated GHG emissions. Daily capacity is 1.1 billion cubic feet (bcf). Decree 10/2007 created a special legal regime for the ALNG that includes specific maritime, tax, customs, and foreign exchange regimes. The ALNG is subject to a specific tax regime under which sponsor entities hold a tax credit of 144 months starting from the date of initial commercial production, deductible against the Profit Income Tax. The ALNG is subject to a quarterly gas tax from the first LNG export shipment date. Decree 7/2018 provides more attractive tax rates to gas operations. The gas production tax is 5 percent (compared with 10 percent for oil).

PSCs state that any surplus gas produced by oil companies that is not used for field use must be given free of charge to Sonangol (see section 5 of this chapter). The capital expenditures borne by companies for the storage and delivery of associated gas to Sonangol are cost recoverable. Sonangol will manage the gas infrastructure once commissioned and will also bear the cost of operating it. Should funding the gas infrastructure have a significant negative impact on the economic conditions agreed to in the PSCs for the contractor, Sonangol is required to modify the economic terms of the contract to restore the contractor’s economic position before the gas infrastructure project.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
The fact that midstream licenses do not provide open access rights to third parties in privately constructed infrastructure could be a barrier to the commercialization of associated gas. These licenses are typically granted to companies affiliated with Sonangol. Third parties do not have access to such infrastructure if the right-of-way has already been granted for the midstream license.
Argentina

1.24 billion cubic meters of gas flared in 2021
(total oil production 507 thousand barrels per day)

Change in Flare Gas Volumes*  
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Change in Flare Gas Intensity**  
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* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 3 Gas flaring volume and intensity in Argentina, 2012-21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Argentina doubled from 0.6 bcm in 2012 to 1.2 bcm in 2021 (figure 3). During this period, oil production varied by about 10 percent. After broadly stabilizing in the first half of the 2010s, the flaring intensity increased steadily after 2017, reaching the highest level in 2021 since 2012. There were 110 individual flare sites in the last flare count, conducted in 2019.

Argentina participates in the Global Methane Initiative (n.d.) and the Climate and Clean Air Coalition. It submitted its first NDC in 2016 and its second in 2020. In its second NDC, Argentina committed not to exceed net emissions of 359 million tCO₂e by 2030. This new goal is 26 percent lower than the target in the 2016 NDC. It represents an emissions reduction of 19 percent by 2030 from the 2007 peak emissions level.

2. Targets and Limits

Section 3 of Annex 1 of Resolution No. 563/1998, n.t. sets out limits on and requirements for gas venting at the federal level. Gas venting from production wells is allowed if the gas-to-oil ratio at the venting point does not exceed the maximum limit of 1 m³ of gas per m³ of oil as of January 1, 2000. Section 3 prohibits venting in all wells in which the gas-to-oil ratio exceeds 1,500 m³ of gas per m³ of oil, regardless of the composition of the gas produced. These wells should remain shut if the conditions for the capture and use of the gas have not been resolved with the authorities.

B. Legal, Regulatory Framework, and Contractual rights

Section 7 of Annex 2, on model contracts, of Decree No. 1443/1983, n.t. issued by the Federal Executive Power (Poder Ejecutivo Nacional), prohibits flaring or venting of gas except as authorized by the application authority. Resolution No. 105/1992 regulates flaring and venting standards and procedures to protect the environment during hydrocarbon exploration and production. The resolution states that associated gas with carbon monoxide, sulfur dioxide, or hydrogen sulfide can be flared. Noncombustible...
gas produced (CO₂) can be vented. Resolution No. 14/1998 (see footnote 33), replacing Resolution No. 236/1993, requires that unused gas be burned, allowing vents only when burning is technically infeasible, and sets venting limits and requirements. Certain provinces have issued specific rules governing flaring and venting. They apply the Energy Secretariat's standards in the above resolutions.

The federal Hydrocarbon Law No. 17,319, 1967 (Hydrocarbon Law 1967 hereafter)36—as amended by Law No. 26.197, 2006,37 and Law No. 27.007, 2014,38 among others—regulates oil and gas exploration, development, and production. The 2007 transfer of the domain of oil and gas areas to provinces limited the federal government’s power in the hydrocarbon industry’s design and management. Law No. 27.007, 2014,38 reinstated to the federal government some of its prerogatives by restricting provincial rights. The main aims of the 2014 amendments were to reverse declines in production, increase imports of hydrocarbons, and boost exploration and production, especially of unconventional resources. The law distinguishes between exploration permits for conventional and unconventional hydrocarbons and between exploration in the territorial sea and continental shelf. Law No. 26.609, 201139 as amended by Law No. 26.915, 2013, regulates offshore exploration and production activities.

Some provinces have issued specific legislation for the oil and gas sector, others have adopted the federal standards in their respective laws. In the Neuquén province, Law No. 1,926, 1991,40 and its associated regulation Provincial Decree No. 2,247/1996, establish and define the responsibilities of the Provincial Secretariat of Energy and Mining (currently the Undersecretary of Energy, Mining, and Hydrocarbons) as the authorizing and enforcement authority for oil and gas activities. The Neuquén province—which issued Hydrocarbons Law No. 2,453, 2004,41 and the associated regulation, Provincial Decree No. 3,154/2004,42—established the framework for the exploration, production, industrialization, transportation, and marketing of hydrocarbons and their by-products. Hydrocarbons Law XVII-102, 1973,43 reaffirms that Chubut has complete administrative control over the hydrocarbon deposits located in the province. Provincial Law No. 4,29645 reaffirms that Río Negro has complete administrative control over the hydrocarbon deposits located in the province, including near coastal areas. These provincial laws are within the framework of federal Law No. 17,319, 1967, and Law No. 26,915,2006.

Article 41 of the 1983 National Constitution46 transfers legislative powers with respect to general environmental matters from the provinces to the federal government. At the federal level, general legislation containing minimum environmental protection standards, such as Law No. 25,675 General Environmental Law, 2002, govern the oil and gas sector.47 Resolution No. 25,20448 defines the technical characteristics, structure, and scope of environmental studies and annual environmental monitoring reports to be submitted by oil and gas companies pursuing exploration and exploitation activities. In 2019, the National Congress passed Law No. 27,520, 2019,49 which set minimum standards for climate change adaptation and mitigation. The provinces are empowered to supplement the federal environmental regulations with local regulations, provided they do not overstep the established principle of federal law primacy. Several provincial regulations for controlling gaseous emissions have been passed in connection with environmental matters. For example, Law No. 2,175/1997,50 and its associated regulation Neuquén Provincial Decree No. 29,200151 regulate environmental protection and health issues associated with natural resources development in the Neuquén province.

4. Legislative Jurisdictions

Argentina has a highly decentralized federal system of government in which provinces play a significant role. Law No. 26,197, 2006, which amended the Hydrocarbons Law, provides that the oil and gas fields belong to the federal government or the provinces in which the fields are located. Provincial governments are responsible for granting exploration permits and production concessions, enforcing laws and regulations, and administering the oil and gas fields. Law No. 27,007, 2014 prescribes that provincial governments are responsible for offshore oil and natural gas resources up to 12 nautical miles. Hydrocarbon deposits found within 12 nautical miles of the continental shelf’s outer limit are the federal government’s responsibility. However, the provincial administrative powers must be employed within the framework of the Hydrocarbons Law and its regulations. This requirement means that the power to define the standards for climate change adaptation and mitigation is in the hands of the federal government and Congress. The primary laws and regulations governing flaring and venting are federal.

5. Associated Gas Ownership

Hydrocarbons are exploited primarily via concessions. At the federal level, Article 6 of the Hydrocarbon Law, 1967, states that licensees obtain the rights to extracted hydrocarbons and can transport and commercialize them, complying with the regulations issued by the executive power. Article 63 states that no royalties will be imposed on hydrocarbons used by the licensee. The royalty rate was 12 percent in 2019.52 With the approval of the Undersecretariat of Hydrocarbons,53 the licensee may determine the destination and conditions for the use of the gas.

In the case of the Neuquén province, Article 6 of Hydrocarbons Law No. 2,453, 2004 (see footnote 41) states that the license holders will obtain the rights to the hydrocarbons they extract. As a result, they have the right to process, transport, and commercialize extracted hydrocarbons and their derivatives, subject to compliance with the regulations issued by the provincial executive power.

C. Regulatory Governance and Organization

6. Regulatory Authority

Gas flaring and venting are regulated at the federal and provincial levels. The federal regulatory authority is the Undersecretariat of Hydrocarbons (Subsecretaría de Hidrocarburos), part of the Federal Energy Secretariat (Secretaría de Gobierno de Energía). The federal regulatory authority for natural gas is the Energy Secretariat. Decree No. 7,2019 created the Ministry of Productive Development and placed the Energy Secretariat under its authority. Each oil- and gas-producing province has its own regulator, governed by the Hydrocarbons Law, 1967, and by provincial legislation and regulations. The regulatory authority is the Undersecretariat of Energy, Mining, and Hydrocarbons, under the Ministry of Energy and Natural Resources in Neuquén, the Ministry of Hydrocarbons in Chubut, the Energy Institute55 in Santa Cruz, and the Energy Secretariat56 in Río Negro.

7. Regulatory Mandates and Responsibilities

At the federal level, authorization and enforcement for flaring

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and venting are the responsibilities of the Energy Secretariat. At the provincial level, the regulators listed in the previous section authorize flaring or venting and enforce related regulations. The Ministry of Environment and Sustainable Development is responsible for establishing the minimum environmental protection standards for the sustainable management of the environment, preserving and protecting biological diversity, and implementing sustainable development. Decree N° 2.656/1999 clarifies that the “permitting authority” supervises and inspects the operational aspects of the oil and gas activities. By contrast, the environmental authority, the Undersecretariat of Environment, enforces the environmental aspects.

8. Monitoring and Enforcement

Law No. 26.197, 2006, grants the following powers to the provinces:
- control over all activities related to the supervision and control of the exploration permits and production concessions
- enforcement of all applicable legal and contractual obligations regarding investments, production, provision of information, and surface use and royalty payment
- extension of legal and contractual terms

Federal Resolution No. 143/1998 (see footnote 33), Provincial Law No. 2.175/1997 (see footnote 50), and Neuquén Provincial Decree No. 29/2001 (see footnote 51) fully empower the regulators to monitor and audit the oil and gas industry.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Resolution No. 143/1998 (see footnote 33) prescribes that gas be flared, not vented, through appropriate procedures. If, for technical reasons, the gas cannot be flared, the operator is required to submit a report to justify venting. Annex 1 (“Normas y Procedimientos para Ventas Gas”) lists the circumstances under which gas venting is allowed:
- Section 3.1 permits flaring or venting when the gas-to-oil ratio at the vent point does not exceed 1 m³ of gas per 1 m³ of crude oil produced.
- Section 4.4 permits periodic venting of gas when there are no conduction lines to capture the gas at the wellhead.
- Section 5 permits venting when it occurs during well testing. The authorities should be notified in writing of all flaring and venting for all causes (maintenance, operations, or emergencies) within 24 hours. The reasons for the contingency, flow rates and damages, and the immediate measures and corrective measures implemented must be detailed.
- The Neuquén Province Law 2.175/1997 (see footnote 50) prohibits gaseous emissions from oil and gas wells. Emissions from flares can be authorized for oil wells if the emissions are not characterized as a hazardous waste. Article 2 of Decree No. 29/2001 (see footnote 51) requires the operator to submit a report documenting a justification for venting if the unused gas cannot be flared for technical reasons and to follow the same criteria for venting as stipulated in Resolution No. 143/1998.

10. Authorized Flaring or Venting

Article 4 of Resolution No. 143/1998 requires the operator to submit a request for exemption to the undersecretary for breaching the permitted limits. Annex 1 of the resolution describes the procedure for submitting such a request. The regulator has 90 days from the date of receipt of the request to issue the approval or rejection of the request. Every request for an exemption must demonstrate for each reservoir the technical reasons for exceeding the limits and the maximum flow rate of gas to be flared or vented. The documentation and data should be updated every six months by May 31 and November 30 of each year in which exemptions are requested.

Section 3 of Annex 1 of Resolution No. 143/1998 states that the Energy Secretariat may judge whether venting should be reduced, either temporarily or permanently, on a case-by-case basis. Section 3 requires allowed venting to follow appropriate procedures and minimize the emissions of harmful gases into the environment. Section 3 also states that Sections 3, 4, and 5 of Resolution No. 105 should be followed in all cases. The Neuquén province’s Decree No. 29/2001 (see footnote 51) outlines the same criteria as Resolution No. 143/1998.

11. Development Plans

No information specific to requiring a development plan for associated gas as part of the field development approval for greenfield projects was identified. However, Federal Resolution N° 105/1992 (see footnote 35) requires the operator to prepare an EIA for the development phase. The EIA must specify the installations to manage associated gas or dispose of it after a technical-economic study confirms that its use is not viable. Article 20 of the Neuquén province’s Decree N° 2.656/1999 (see footnote 58) outlines norms and procedures regulating environmental protection during oil exploration and production similar to those in Resolution No. 105/1992.

12. Economic Evaluation

Resolution No. 143/1998, subsection 5 of Annex 1 (“Normas y Procedimientos para Ventas Gas, Section 5, Reasons for Exception—Gas Venting”) requires a technical and economic feasibility study in cases in which gas at the venting point has a high content of inert or toxic gases and the gas-to-oil ratio in each well is less than the 1,500 m³ of gas per m³ of oil, the limit stipulated in Section 3.2. The study should include analysis of the effects of the flow rate and total volume of vented gas. This analysis should demonstrate that neither the flow rates nor the volumes to be vented will reduce the exploitation of the gas. The study should include the flow rates and composition of the vented gas and the disposal method for each type of toxic gas produced. The Neuquén province’s Decree No. 29/2001 sets the same criteria as Resolution No. 143/1998.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Section 6 of Annex 1, on norms and procedures for venting gas, of Resolution No. 143/1998 (see footnote 33) covers flow rate measurement and registering. It requires the establishment and implementation at each venting point of a system to measure and record the flow of flared or vented gas and its composition in all cases. Article 14 of the Neuquén province’s Decree No. 29/2001 includes similar requirements (see footnote 51).

14. Measurement Frequency and Methods

Per Resolution No. 143/1998, flaring and venting of gases should be reported monthly to the authorities, including the location of the installation, flow rate, composition, causes of flaring or venting, measurement points, and points of emission. Article 7 of the Neuquén province’s Decree No. 29/2001 requires monthly submission of an affidavit (sworn declaration) documenting all gas emissions from oil wells. The original documentation of the sworn declaration should be submitted to the Provincial Directorate of Hydrocarbons and Fuels within 10 calendar days of the end of the month being reported.

15. Engineering Estimates

Subsection 6 of Annex 1 (on norms and procedures for venting gas) of Resolution No. 143/1998, which applies nationally, allows estimation of flow rates based on the last determination of the gas-to-oil ratio and the gas composition in the well when the gas is released to unblock a pump.

16. Record Keeping

Section 6 of Resolution No. 143/1998, 1998, states the records should be kept on an annual basis. Article 14 of the Neuquén province’s Decree No. 29/2001 requires flaring and venting records to be retained for five years, not the one year required nationally.

17. Data Compilation and Publishing

Data on oil and gas production and disposition, including vented volumes of gas, are compiled at the national level and posted on a governmental website. The information can be filtered by province, year, concession area, and month. Information on vented gas volumes, which can be found in the “Gas Balances” file, has been compiled since 2009.

F. Fines, Penalties, and Sanctions

Aside from penalties for general violations of the laws,
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regulations, and technical provisions, no specific monetary penalties for flaring or venting were identified. Article 87 of the Hydrocarbon Law, 1967 (see footnote 36) sets fines for failure to comply with any of the obligations arising from authorizations and concessions that do not constitute causes for revocation. Decree No. 488/202060 introduces a new formula for calculating the fines in its Article 10. The fines vary with the severity and incidence of the breach, ranging from a minimum equivalent to the value of 22 m³ of national crude oil in the domestic market to a maximum of 2,200 m³ of the national crude oil in the domestic market for each violation.

Article 6 of the Neuquén province’s Law No. 2.175, 1997 (see footnote 59) subjects emissions of unauthorised associated gas above the limits established in Article 5 to monthly payments. Article 2 in Decrease 29/2001 (see footnote 51) takes only the volume of gases released into account to calculate the rate to be charged for gas venting. Since December 31, 2001, these volumes have been set per cubic meter of gas flared or vented, beginning at 500 percent of the weighted average sales price of natural gas at the custody transfer point. Article 8 states that noncompliance with the limits imposed on associated gas from oil wells is subject to fines, based on the gravity of the offense, determined by the quality and quantity of the gas. The frequency of payments is monthly.

A newspaper article61 dated September 21, 21, indicates that a provincial regulator, the Secretaría de Energía de Río Negro, imposed a penalty on the national oil company, YPF for venting rather than flaring. The fine was Arg$134,000 (about US$1,350 at August 25, 2021). Following the formula introduced in Decrease 488/202020, YPF tried to reverse the fine by appealing to the Civil Chamber of Cipellotti. The ministry stated that YPF had committed 11 infractions since the renegotiation of its oil contracts, when it had agreed to make sizable investments in its infrastructure if they comply with the relevant procedures.

The growth of natural gas production will require substantial new investment in infrastructure and export routes in the near and medium term as well as cost-effective production and transportation systems. The federal government launched a public tender for constructing and operating a new gas pipeline from the Vaca Muerta area in Neuquén to Saliquelo south of Buenos Aires. Construction is underway.

19. Nonmonetary Penalties

Section 9 of Resolution No. 143/1998 (see footnote 33) on inspections and sanctions, cites noncompliance with it as a sufficient reason for revoking the corresponding authorizations, except where the Energy Secretariat deems the noncompliance justified. Section 9 sets out the appeal process. Any transgression of the resolution will make the concessionaire or permit holder liable to the sanctions imposed in Law N° 17.319, 1997 under the law’s Titles VI and VII. The Energy Secretariat may request the revocation of the concession or exploration permit granted in the event of the assumptions outlined in Article 80 of the law.

20. Performance Requirements

No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives

Section 8 of Annex 1 of Resolution 143/1998 (see footnote 33) states that as a condition for granting the exception to gas venting, the licensees must provide a guarantee of investments in emission abatement within 15 calendar days from the notification of the approval to the company. The amount of the guarantee depends on the emission flows during the exception period and the abatement investments to be made. Guarantees are set for each project by semester or as a fraction of the exception period and of the investment to be made. The guarantee will be called if the company does not execute the agreed investments for each project at the expiration of each term.

22. Use of Market-Based Principles

YPF has two projects registered under the CDM, intended to reduce emissions in the La Plata and Lujón del Cuyo industrial complexes. In 2019, the two projects combined avoided about 486,687 tCO₂, emissions. YPF also engages in carbon offset programs, such as reforestation in the Neuquén province. Started in 1998, these efforts are estimated to have sequestered 760,000 tCO₂e over the course of 30 years.

23. Negotiated Agreements between the Public and the Private Sector

YPF has committed to minimising gas flared and vented, in compliance with the requirements established in Federal Resolutions No. 236/1993 and No. 143/1998. Through its innovation department, YPF is developing two pilot projects that seek to eliminate gas flaring and venting. One project, implemented in the Bajada de Añelo area, compresses captured associated gas to make CNG. The second project, carried out in a partnership with Galileo, involves an on-site mini-plant that liquefies the gas, which is transported in cryogenic tanker trucks. After ten liquefaction plants were installed in 2017 to capture gas at seven wells in Neuquén and Mendoza, 150,000 m³ of gas were supplied daily for power generation.

24. Interplay with Midstream and Downstream Regulatory Framework

Natural gas provides more than 60 percent of power generation and more than half of the total energy consumed. Law No. 24.076, 1992, known as the Natural Gas Law, established the basis for deregulation of natural gas transportation and distribution industries. The Federal Gas Regulatory Authority, created in 1992 by Decree No. 2255/92, oversees the transportation and distribution of natural gas.

Natural gas prices are a mix of regulated and market prices. Before the 2015 energy reform, domestic oil and gas prices were significantly lower than those at trade parity, and public services tariffs did not cover operational costs. The domestic supply of oil and gas was insufficient to meet demand. After 2015, domestic oil and gas prices started to align with international levels. Resolution No. 46/2017,62 as amended by Resolution No. 419/2017 and 12/2018, introduced producer subsidies to attract investments in unconventional natural gas reservoirs in the Neuquén Basin. A minimum price of US$7.50 per million British thermal units (mmBtu) was guaranteed during 2018, decreasing by US$0.50/mmBtu a year to US$6/mmBtu by 2021. On December 31, 2021, the program will end, at which point prices are expected to match import-parity values.

Law No. 26.197, 2006, vests the federal government with the authority to grant concessions for interprovincial and export transportation. Transportation concessions located within the territory of only one province and not connected to export facilities were transferred to the provinces. Operators of pipelines and other transport and distribution infrastructure are required to provide open access to third parties if they have available capacity. Third parties have the right to access this transport infrastructure if they comply with the relevant procedures.

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0.91 billion cubic meters of gas flared in 2021
(total oil production 2,906 thousand barrels per day)

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Brazil decreased from 1.6 bcm in 2012 to 0.9 bcm in 2021. During this period, oil production rose by more than two-fifths, but associated emissions were more than offset by the 56 percent decline in flaring intensity (figure 4). The last flare count, conducted in 2019, found 63 individual flare sites.

In 2018, the national oil company, Petrobras, endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). Petrobras also participates in the Global Methane Initiative (n.d.; see footnote 29). In 2020, Petrobras submitted an updated NDC to the UNFCCC and committed to reducing its GHG emissions from 2005 levels by 37 percent by 2025 and 43 percent by 2030. However, the NDC does not specifically mention gas flaring and venting.

As a result of flaring reduction and other initiatives, upstream carbon intensity declined by 25 percent between 2009 and 2015. Between 2008 and 2018, almost 10 million tCO₂ from associated gas was re-injected. Petrobras estimates that the company’s average gas use in 2018 was 97 percent.

Resolution 17/2017 issued by Brazil’s National Council of Energy Policy’s (Conselho Nacional de Política Energética) outlines the policy on oil and gas exploration and production. It establishes a guideline to increase, on an economic basis, the share of natural gas production for the domestic market, including by reducing the flaring of natural gas in upstream activities.

B. Legal, Regulatory Framework, and Contractual rights

Law 9478/1997, Petroleum Law (Petroleum Law, 1997, hereafter),66 governs oil and gas upstream activities in Brazil. Article 7 establishes the ANP67 as the lead oil and gas agency. Article 25 states that only companies that meet the ANP’s technical, legal, and economic requirements can be awarded oil and gas exploration and production concession. Article 26 states that operators should submit their development and production projects and plans for the ANP’s approval.

Law 11.909/2009, Natural Gas Law,68 covers the transportation of natural gas, previously covered by Article 77 of the Constitution, as well as treatment, processing, storage, liquefaction, regasification, and commercialization of natural gas.

Resolution 806/2020 replaces ANP Ordinance (“Portaria”) 249/2000 and details the criteria and procedures for controlling and reducing gas flaring and venting in upstream activities. Article 4 states that the flaring or venting of nonassociated natural gas...
Regulation of Gas Flaring and Venting: 28 Case Studies from around the World

Brasil

is prohibited unless authorized for reasons of safety, emergency, testing, or the cleaning of wells. Other articles of the resolution detail conditions and requirements for flaring and venting and with prior authorization (see sections 9 and 10 of this chapter). ANP Ordinance 123/2000 (see footnote 69) establishes the technical rules for the oil and gas PAP.

Article 177 of the Federal Constitution, 1988, as modified by Constitutional Amendments 9/95, 33/97, and 49/06, establishes the federal government’s monopoly over the exploration and exploitation of Brazil’s oil and natural gas deposits. Brazil currently has three legal regimes applicable to upstream oil and gas activities:

- concession, regulated by Petrochemical Law, 1997
- production sharing, regulated by Law 12351/2010
- transfer of acreage in the pre-salt zone to Petrobras, regulated by Law 122/67/10, 2010.

Article 225 of the Federal Constitution, 1998, provides the main framework and provisions for environmental protection in Brazil. The most important piece of legislation is Law 6,938, the National Environmental Policy Act, 1981.

4. Legislative Jurisdictions

Articles 3 and 21 of the Petroleum Law, 1997, place all oil and gas activities under national jurisdiction.

5. Associated Gas Ownership

Articles 20 (items V and IX) and 176 of the Federal Constitution, 1988, and Article 3 of the Petroleum Law, 1997, vest the oil and gas deposits in the territory, the continental shelf, and the exclusive economic zone in the federal government. Article 26 of the Petroleum Law, 1997, states that the concessionaire owes measured volumes of extracted oil and gas at the production measurement point, with charges related to the payment of the applicable taxes and the corresponding legal or contractual obligations. There is no difference in the treatment of oil and gas.

Gas flared and vented is subject to royalties. The Concession Agreement for Exploration and Production of Oil and Gas states that natural gas that is flared or vented should be included in the total production volume calculated for the purpose of paying royalties to the government.

C. Regulatory Governance and Organization

6. Regulatory Authority

According to Article 7 of the Petroleum Law, 1997 (see footnote 71), the ANP under Minister of Mines and Energy (Ministerio de Minas y Ener‐gía [MME]) is responsible for regulating all petroleum industry activities. It is responsible for formulating Brazil’s policies in the energy sector. The council comprises government representatives (including seven ministers), outside energy experts, and nongovernmental organizations. The Energy Research Office (Empresa de Pesquisa Energética [EPE]) was established by Law 10064/2000. It supports the MME’s energy policies with studies and research on energy planning, including for electricity, oil, natural gas, and biofuels. Law 7735/1989 created the Brazilian Institute of Environment and Renewable Natural Resources (Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais), the administrative arm of the Brazilian Ministry of the Environment.

7. Regulatory Mandates and Responsibilities

The oil and gas sector is under federal jurisdiction; the ANP regulates all activities related to the industry. According to Article 8 of the Petroleum Law, 1997, the purpose of the ANP is to oversee the regulation, engagement, and inspection of economic activities in the oil, gas, and biofuel industries. Resolution 806/2020 (see footnote 70) regulates the flaring and venting of associated gas.

According to Chapter 4 of Ordinance 422/2011, the Brazilian Institute of Environment and Renewable Natural Resources is responsible for environmental licensing of oil and gas activities. The institute can also impose environmental permit conditions related to flaring and venting, with a focus on the prevention and mitigation of GHG emissions.

8. Monitoring and Enforcement

Chapter 4 of the Petroleum Law, 1997 (see footnote 71) empowers the ANP to undertake all measures necessary to regulate, monitor, and control activities related to the oil and gas industry.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 2 of Resolution 806/2020 (see footnote 70) defines “ordinary flares” as flaring or venting of gas that does not require prior authorization. Article 3 states that the volume of ordinary flaring or venting of natural gas carried out each month cannot be higher than that corresponding to the Associated Gas Utilization Index (Índice de Utilização de Gás Associado [IUGA]) for the same month in the approved PAP with a permitted exceedance of 15 percent. Sanctions are applied to each monthly infraction. Article 14 states that authorization is not needed in case of emergency flaring or venting. Operators should provide ANP validation of the volume of gas flared or vented during emergencies.

Article 6 states that flaring or venting associated gas does not require the ANP’s prior approval in the following cases:

1. Flaring or venting of associated gas in volumes equal to or less than
   a. 3 percent (IUGA greater than or equal to 97 percent) of monthly offshore production of associated gas in fields in operation five years before the date of the publication of the resolution (before January 17, 2025) and 2 percent (IUGA of 98 percent or greater) in fields that start production five years or later after the date of the publication of this resolution (after January 17, 2025)
   b. 1.5 percent (IUGA of 98.5 percent or greater) of the monthly associated gas handled by a marine production unit for lifting oil or received from other units in volumes equal to or greater than 50 percent of the volume of gas handled
   c. 3 percent (IUGA of 97 percent or greater) of the monthly onshore production of associated gas

2. When the volumes of associated gas flared are greater than those approved, but the new (or revised) IUGA is equal to or greater than the one considered in the most recent approved PAP

3. Flaring of petroleum or flaring or venting of natural gas during well testing with a flow period of 72 hours or less per interval tested.

4. Flaring or venting of associated gas in fields that produce a total monthly volume equal to or less than that corresponding to an average flow rate of 5,000 m³/day as long as the field does not have wells with an average flow rate above 1,500 m³/day, for which a project using associated gas should be proposed.

5. Flaring or venting of associated gas produced in onshore fields or marine production units with a gas-to-oil ratio of 20 m³ of gas per m³ of crude oil or less.

6. Flaring for safety reasons. For onshore production units, a limit on a maximum monthly volume of 1,000 m³/day for each pilot/flare. The offshore limit is 2,000 m³/day for each pilot, provided that such pilots are operational.

Articles 7–16 define the criteria and procedures for authorization and validation of extraordinary flares and circumstances under which extraordinary flaring and venting of associated gas are allowed without prior approval.

10. Authorized Flaring or Venting

Article 2 of Resolution 806/2020 defines “extraordinary flaring” as associated gas flaring and venting subject to the ANP’s prior authorization or subsequent validation. Article 3 requires the ANP’s approval of the PAP, which must include forecasts of routine gas flaring and venting and volumes flared or vented that would not be subject to royalties. Article 7 states that the ANP’s authorization of extraordinary flaring should be requested.
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with notice of a minimum of 30 days. Articles 8–16 establish the procedures and criteria for authorization or subsequent validation of “extraordinary flaring.”

The annual production programs approved by the ANP may contain specific conditions, including those related to flaring or venting, in addition to those imposed by Resolution 806/2020. ANP Ordinance 123/2000 (see footnote 69) provides the procedures to be followed for approval. Resolution 806/2020 provides the technical criteria. Chapter 4 of Ordinance 422/2017 (see footnote 82) authorizes the Brazilian Institute of Environment and Renewable Natural Resources to set conditions for environmental licenses, including controlling emissions discharged to the atmosphere.

11. Development Plans

Article 44 of the Petroleum Law, 1997 (see footnote 71) requires the inclusion of associated gas use in the field development plan submitted to the ANP for approval after the declaration of commercial viability for a given project. The plan should consist of a schedule and investment estimate. Resolution 17/201584 provides guidelines for field development plans. Article 16(3) requires the submission of volumes expected for gas lift, internal consumption, re-injection, and flaring and venting, as well as mitigation plans for reducing gas flaring.

12. Economic Evaluation

Section 8.1.6 of ANP Ordinance 123/2000 (see footnote 69) stipulates that the PAP should include the volume of associated gas that would not be used or re-injected. The PAP must also demonstrate, based on economic evaluation, that the oil or gas production of the field would not be economically feasible if the gas so identified cannot be flared.

To reduce flaring, the production of oil and gas may be started only after the installation of a system that utilizes or re-injects any natural gas, unless the ANP grants an exception upon consideration of the economic evaluation.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

ANP/Inmetro Joint Resolution No. 12/2013 contains the technical regulation for the measurement of oil and natural gas. According to Article 9 of Resolution 806/2020 (see footnote 70), operators should provide the ANP with monthly production reports that include gas flaring and venting data. The report must be submitted by the 15th day of each month. Operators should report estimates of flared or vented associated gas for each of the following categories:

• safety
• scheduled maintenance
• works in progress, such as facilities under construction
• low gas production (insufficient volume of gas to be used)
• economics (associated gas whose use or re-injection would make the field uneconomic)
• venting in tanks (associated natural gas vented)

The Model Contract-Concession Agreement for Exploration and Production of Oil and Gas94 explicitly mentions the requirement for reporting the volumes of gas flared or vented in Section 12. According to Subsection 12, licensees should submit to the ANP a monthly report on the production of each development area or field according to the applicable laws and regulations. Gas flaring and venting of natural gas with a variation above 15 percent of the volumes authorized in the PAP must be accompanied by due justification. According to Subsection 12, the licensee’s flaring and venting of gas should be included in the total production volume to be calculated for the purpose of paying royalties to the government. In this case, the flared volumes are monitored daily through the Production Inspection System (Sistema de Fiscalizacao da Producao).

14. Measurement Frequency and Methods

Resolution 806/2020 (see footnote 70) requires the concessionaire to regularly measure the volume and quality of the oil or gas produced in each development area or field from the production start date, using the measurement methods, equipment, and tools established in the development plan and in the applicable laws and regulations. The specifics of the frequency of volume measurements or measurement methodology could not be identified in the sources consulted.

15. Engineering Estimates

No evidence regarding engineering estimates could be found in the sources consulted.

16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted.

17. Data Compilation and Publishing

The ANP’s Development and Production Superintendence produces a monthly report entitled “Oil and Natural Gas Production Bulletin,” which provides information on Brazilian oil and gas production, including flaring data. The most recent data are from March 2020.95 Reports are published on the government’s website.96

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

According to the ANP’s interpretation of Article 2 of Law 9867/1999 and subsequent decisions, infractions involving flaring or venting subject to fines or nonmonetary sanctions. Article 3 states that the monetary penalty ranges from R$5,000 to R$2,000,000 (about US$960–US$3,800 as of September 2021). The ANP determines the monetary penalty for flaring or venting according to the seriousness of the infringement and the operator’s previous infraction history under ANP Ordinance 397/2016. Article 13 provides for the right to appeal.

Decree 2953/199989 sets forth the administrative procedure for applying penalties for infractions committed in activities related to the oil industry and the national supply of fuels. Administrative sanctions may take the form of fines and nonmonetary sanctions (see the next section). According to Article 26, the fine should be paid within 30 days of the date of acknowledging the infraction. Failure to pay the fine within the specified period will subject the offender to a default interest rate of 1 percent and a late payment penalty of 2 percent a month or a fraction thereof.

Section 3 of Resolution 806/2020 (see footnote 70) states that the operator is subject to a sanction each month the volume of gas flared or vented exceeds the level authorized in the most recently approved PAP. Articles 1 and 2 of Resolution 774/201997 allow operators to make the penalty payment in up to 60 monthly installments, in accordance with the conditions to be negotiated with the ANP.

Data on fines imposed by the ANP during 2011–2015 are available for download on the ANP website.98 Information on fines for flaring and venting after 2015 has not been posted. During 2011–15, 177 fines were imposed, of which 94 were for flaring gas in volumes higher than authorized. These fines totaled R$121,700,000 (about US$23 million). The fines applied from 2016 to 2018 have been published, but there is no specific information on flaring and venting during that period.

In October 2014, the ANP fined Petrobras a total of R$6 million (about US$1.1 million as of September 2021) for flaring violations committed in the production of the onshore field of Fagenda Santa Luzia in the north of the Espirito Santo state. According to the ANP, Petrobras flared associated gas in April, May, September, October, and November 2010 in an amount higher than provided for in the Annual Production Plan. The company asked for the suspension of fines. On October 15, 2020, the courts upheld the fine imposed by the ANP. In another action, Petrobras requested the suspension of the collection of fines, totaling about R$16 million, for irregularities found in the measurement system of the Zapir I Platform in the Santos Basin.99 The irregularities were
detected during an inspection by the ANP in March 2012.

19. Nonmonetary Penalties
According to the ANP’s interpretation of Article 2 of Law 9847/1999, infractions involving flaring or venting may be subject to suspension of operation. Article 13 provides for the right to appeal.

Under Decree 2953/1999, nonmonetary sanctions can take the form of suspension of product supply; temporary suspension, total or partial, of the facility or installation; cancellation of registration of an installation; and revocation of authorization to carry out the associated activity. Sections 1 and 2 of the decree provide administrative penalty procedures; Sections 3 and 5 describe the appeal procedures. The defendant has 15 days to present evidence to contest the charges, and the ANP has 30 days to evaluate and decide on the case. If the decision rules against the operator, a second appeal can be mounted within 10 days. The ANP director will decide on the appeal within a maximum period of 30 days, starting from the date of the submission of the appeal.

20. Performance Requirements
No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives
According to Law 9847/1999 (see footnote 88), the volume of gas flared under the responsibility of the concessionaire will be included in the total volume of production used for calculating royalties. The royalty rate is typically 10 percent but can be as low as 5 or as high as 15 percent. Royalties on oil and gas production are fully tax-deductible.

The royalty rate is typically 10 percent but can be as low as 5 or as high as 15 percent. Royalties on oil and gas production are fully tax-deductible.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector
The main instruments for controlling gas flaring and venting in Brazil are the field development plan, the PAP, the monthly production reports, and the Terms of Commitment. The Terms of Commitment are agreements for the reduction of volumes flared over the medium term that contain targets for the use of associated gas and action plans that guarantee compliance with them. Three such agreements have been signed, two with Petrobras and one with Chevron.

Important initiatives on flaring reduction in Brazil are Petrobras’ 2009 Gas Optimization Program and the signing of the second Term of Commitment between Petrobras and the regulator, as a direct consequence of the finding that the volume of gas flared exceeded the limits allowed by ANP’s Ordinance 249/2000.

Under the Adjustment Program to Reduce Natural Gas Flaring in the Campos Basin, Petrobras reduced emissions by more than 40 percent between 2009 and 2019, despite increasing oil production. Since then, the ANP has been restricting authorized volumes of extraordinary flaring of natural gas. Petrobras has committed to eliminating the absolute growth of its operational emissions by 2025 and eliminating routine flaring by 2030.

The company has developed technologies to capture and re-inject CO₂ into the oil fields, especially in the pre-salt area. The company has also invested in research through its association with the Oil and Gas Climate Initiative. Petrobras has also released its second climate supplement, outlining its climate commitments and explicitly supporting the Task Force on Climate-Related Financial Disclosures.

24. Interplay with Midstream and Downstream Regulatory Framework
Petrobras was instrumental in creating Brazil’s gas sector, but the company’s control over the industry discouraged new investors from entering the sector and constrained its growth. The New Gas Market is a government program intended to create an open and competitive natural gas market in Brazil. It aims to make the most efficient use of existing infrastructures, attract new investments, and promote competition in the natural gas market. The program has reduced Petrobras’ market power and end-user prices.

Petrobras held a monopoly in Brazil’s oil and gas industry until 1995, when Constitutional Amendment No. 9 was approved, making it possible to introduce competition. The Petroleum Law, 1997 (see footnote 71) implements the constitutional amendment. In the case of natural gas, however, it did not promote a significant change in the market structure, with Petrobras remaining the dominant player and a monopolist by default. Law 11,909/2009, Gas Law (see footnote 73) was adopted to address issues specific to the natural gas industry and attract new investments. It did not achieve the desired objectives.

Resolution 16/2019 established guidelines for an energy policy aimed at promoting competition in the natural gas market and reducing the influence of Petrobras over the market. A Term of Commitment of Assignment (Termo de Compromisso de Cessão) was signed between Brazil’s competition authority and Petrobras. It ended the de facto monopoly of Petrobras. Tax amendments were made providing incentives for gas pipeline transportation (Ajuste SINEF no 03/2018) and Ajuste SINEF no 17/2018.

One of the objectives of Resolution 16/2019 was to improve the recovery of associated gas in the pre-salt basin. The discovery of pre-salt gas could double the potential of natural gas supply in Brazil in the next 15 years. However, pre-salt gas fields are more than 1,500 meters below sea level and about 300 kilometers from the coast. In addition, the pre-salt gas is rich in CO₂, the release of which would increase GHG emissions substantially. The delivery of associated gas will require significant investments in capture and gas treatment infrastructure and offshore pipelines.

\[95\] https://www.globo.com/estadao/blog/capital-e-energia/noticia/2022/03/10/instituto-brasil-e-petrobras-terminam-acordo-para-venda-de-ativos-no-mercado-de-gas-natural.htm
Canada

1.08 billion cubic meters of gas flared in 2021
(total oil production 4,455 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th></th>
<th>2015-2021</th>
<th>2015-2020</th>
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</thead>
<tbody>
<tr>
<td>Flare gas volume</td>
<td>-41%</td>
<td>-41%</td>
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Change in Flare Gas Intensity**

<table>
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<th></th>
<th>2015-2021</th>
<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flare gas intensity</td>
<td>-51%</td>
<td>-48%</td>
</tr>
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</table>

* Annual volumes in billion cubic meters

** Cubic meters of gas flared per barrel of oil produced

Figure 5 Gas flaring volume and intensity in Canada, 2012–21

Change in Flare Gas Volume and Intensity

The country’s GHG emissions from the oil and gas sector have been increasing for several decades. However, nationwide emissions have stabilized since the mid-2000s, thanks to the replacement of coal-fired power generation with gas-fired generation and renewable energy. With the Pan-Canadian Framework on Clean Growth and Climate Change, 2016, Canada committed to reducing methane emissions from the oil and gas industry by 40–45 percent by 2025. In 2018, Environment and Climate Change Canada (ECCC), a Canadian government agency, published Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SOR-2018-66.

2. Targets and Limits

The ECCC’s Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) S.O.R. 2018-66 contain standards for extraction, primary processing, long-distance transport, and storage. The regulations apply to facilities producing or receiving more than 60,000 m³ annually of hydrocarbon gas, which includes methane and certain volatile organic compounds. Upstream oil and gas facilities are required to take the following actions, among others:

- Limit vented volumes to 250 m³ a month, starting in 2023.
- Implement leak detection and repair, starting in 2020. Regular inspections will be required three times a year, and detected leaks are to be repaired within 30 days unless the facility is required to be shut down, in which case an action plan must be prepared and implemented.
- Conserve or flare instead of venting, starting in 2020. Register and keep records to demonstrate compliance.

Provinces set their own flaring and venting rules and emissions limits, which provincial regulators implement. Provincial emission limits must meet or exceed federal targets.

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Canada increased from 1.3 bcm in 2012 to 2.1 bcm in 2014 before falling to 1.1 bcm in 2021 (figure 5). During this period, oil production rose by about a third, but associated emissions were more than offset by the decline in flaring intensity. There were 266 individual flare sites in the last count, conducted in 2019.

Canada has considerable onshore and offshore resources. It produced 6 percent of the world’s crude oil and 4 percent of natural gas in 2019. Alberta, Saskatchewan, and offshore east coast sites accounted for about 50 percent, 30 percent, and 15 percent of Canada’s oil production, respectively. The growth of crude oil production since 2010 can be attributed mainly to increased output from the oil sands in Alberta. Natural gas production is concentrated in Alberta (nearly 70 percent) and British Columbia (nearly 30 percent). The great majority of oil and gas production occurs on state and private land, with the rest coming from federal and tribal lands.

In 2016, Canada endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). It also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 28) and the Climate and Clean Air Coalition (n.d.; see footnote 28). It also participates in the Global Methane Initiative (n.d.; see footnote 29). In July 2021, Canada submitted an updated NDC under the UNFCCC that commits it to reducing GHG emissions by 40–45 percent below 2005 levels by 2030, raising the level of ambition substantially from the original NDC in 2016. There is an increased focus on reducing methane emissions from the oil and gas sector.

The updated NDC is consistent with the federal government’s pledge of Canada’s reaching net-zero emissions economy-wide by 2050.

101 Primary governance of flaring and venting for this majority of production is covered under provincial laws and regulations, as implemented by provincial regulators (see chapters on Alberta, British Columbia, and certain other provinces). Provincial emission limits are to be set in accordance with federal standards. Provincial regulations apply to facilities producing or receiving more than 60,000 m³ annually of hydrocarbon gas, which includes methane and certain volatile organic compounds. Provincial regulations set their own flaring and venting rules and emissions limits, which provincial regulators implement. Provincial emission limits must meet or exceed federal targets.

Canada: Federal

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Canada Oil and Gas Drilling and Production Regulations, 2009,108 ban flaring and venting unless the federal energy regulator permits it or it is necessary because of an emergency. The Canada Oil and Gas Operations Act, 1999,119 governs the exploration, production, processing, and transportation of oil and gas in marine areas controlled by the federal government. Provincial governments have specific legislation governing the exploration and production of oil and natural gas as well as flaring and venting.

The Canadian Environmental Protection Act, 1999,110 regulates pollution prevention and waste management in matters of exploration and production of oil and natural gas, including associated gas, as well as flaring and venting. The mandate, roles, and responsibilities of the CER include designing and collecting royalties.127 The ECCC reports to the federal government’s minister of the environment and is the lead environmental federal agency. The department delivers its mandate through acts and regulations, such as the Canadian Environmental Protection Act, 1999 (see footnote 110). It sets the national ambient objectives for different air pollutants, including those from flaring and venting.

Depending on the jurisdictional and environmental nature of the oil and gas project, an environmental assessment may be required by the provincial government, the federal government, or both per the Impact Assessment Act, 2019.128 Each province has its own regulatory authority to oversee energy and environmental policy and the legal and regulatory framework for upstream, midstream, and downstream operations.

The provincial authorities enforce regulations and standards, operating procedures for managing flaring and venting activities as well as reporting emissions (see the chapters on Alberta, British Columbia, and Saskatchewan).

5. Associated Gas Ownership

The ownership of oil and gas resources is split between the provincial government, the federal government, private freehold owners, and First Nations. Since 1867, the usual practice has been to reserve mineral rights in the granting of land. The Canada Petroleum Resources Act, 1985,123 governs the lease of federally owned oil and gas rights on “frontier lands,” including the “territorial sea” (12 nautical miles beyond the low water mark of the outer coastline) and the “continental shelf” (beyond the territorial sea). Under the act, subsurface oil and gas rights in unexplored areas are issued during a public call for bids, and the successful oil and gas company must pay royalties to the federal government. The rights to explore for, develop, and produce oil and gas, including associated gas, are then transferred to participants through licenses.

C. Regulatory Governance and Organization

6. Regulatory Authority

The Canada Energy Regulator (CER)129 was formed under the Canada Energy Regulator Act, 2019,129 replacing the National Energy Board. It regulates the Northwest Territories, Nunavut and Sable Island, submarine areas not within a province in the internal waters of Canada, and the territorial sea or continental shelf of Canada, as defined in the Canada Oil and Gas Operations Act, 1999 (see footnote 109). The act provides a clear separation between the operational and adjudicative functions of the regulator.

The Canada–Newfoundland and Labrador Offshore Petroleum Board is an independent agency that regulates exploration and production of oil and gas in offshore waters of Canada, and the territorial sea. The mandate, roles, and responsibilities of the Canada–Newfoundland and Labrador Offshore Petroleum Board include the regulation of offshore petroleum and natural gas activities in the Canada–Newfoundland and Labrador offshore area. The Canada–Newfoundland and Labrador Offshore Petroleum Board and the Canada–Nova Scotia Offshore Petroleum Board jointly regulate oil production off the coast of the maritime provinces and set limits on the volumes of gas flared in offshore installations in their respective jurisdictions.

Canada’s constitution grants exclusive authority to the provinces to regulate mineral development within their boundaries. The major producing provinces have independent oil and gas regulators. Federal and provincial (as well as territorial and indigenous) governments share authority over environmental matters. Each province has its own environmental laws.
Canada: Federal

and can be escalated if violators do not take correction actions as ordered by the CER. Provincial regulators have monitoring and enforcement powers that are more directly applicable to oil and gas operations in their provinces.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

The definition of “waste” in the Canada Oil and Gas Drilling and Production Regulations, 2009 (see footnote 108) includes gas flared or vented when it could have been economically recovered and processed or injected into an underground reservoir. Section 67 states that no operator should flare or vent gas unless an emergency requires it to do so. The CER must be notified in the daily drilling report, daily production report, or any other written or electronic form. The notification should include the volume of flared or vented gas. The same provisions can be found in the Newfoundland Offshore Petroleum Drilling and Production Regulations, 2009 (see footnote 120) and the Nova Scotia Offshore Petroleum Drilling and Production Regulations, 2009 (see footnote 121).

Section 48 of the Processing Plant Regulations requires companies to report to the CER within one week of any flaring of hydrocarbon gas occurrence or a by-product of the processing of hydrocarbon gas that occurs as a result of an emergency. Section 6 of the CER Event Reporting Guidelines, 2018 states an emergency as any situation in which emergency or contingency procedures, such as process upsets because of automated or manual emergency shutdowns, were used. Also applicable are flaring events that may have a significant adverse effect on property, the environment, or safety. Companies are not required to report nonroutine flaring, such as that resulting from regulator-required maintenance. Provincial regulators have more specific guidelines on flaring and venting that do not require permits (see the chapters on Alberta, British Columbia, and Saskatchewan).

10. Authorized Flaring or Venting

Section 5 of the Canada Oil and Gas Drilling and Production Regulations, 2009 (Management System, Application for Authorization and Well Approvals, see footnote 108) requires that the application for authorization be accompanied by information about any proposed flaring or venting of gas. This information should include the rationale, rate, quantity, and duration of the flaring or venting. Provincial regulators have more specific guidelines on applying for and obtaining flaring and venting authorizations.

11. Development Plans

Development plans are required and published on the Canada–Newfoundland and Labrador Offshore Petroleum Board website. An example is the public review of the Hebron Development Plan Application, 2011.

12. Economic Evaluation

No evidence regarding economic evaluations by the federal government could be found in the sources consulted. However, provincial regulators consider the economic assessment of options to prevent or reduce flaring and venting.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Part 7 of the Canada Oil and Gas Drilling and Production Regulations, 2009 (‘Measurements Flow and Volume’, see footnote 108) states that unless otherwise included in the approval, the operator should ensure the rate of flow and volume of any produced fluid that enters, leaves, is used, or is flared, vented, burned (incinerated), or otherwise disposed of are measured and recorded. This requirement encompasses any oil storage tanks, treatment facilities, or processing plants. The Newfoundland Offshore Petroleum Drilling and Production Regulations, 2009 (see footnote 120) and the Nova Scotia Offshore Petroleum Drilling and Production Regulations, 2009 (see footnote 121) have similar provisions. The CER Event Reporting Guidelines, 2018 (see footnote 130) require operators to submit an annual production report covering the previous year no later than March 31 of each year. This report must include details on the production forecast and gas conservation as well as efforts to maximize recovery and reduce costs. The report must also demonstrate how the operator manages or intends to manage the resource and avoid waste.

An annual environmental report must also be submitted. This report should include a summary of any incidents that may have had an environmental impact, discharges that had occurred and the waste material produced, and a discussion of the efforts undertaken to reduce pollution and waste material. The ECCC first developed the GHG reporting program in 2004. It has updated reporting and GHG quantification requirements several times. Compliance with the annual reporting of GHG is mandatory. All facilities emitting more than 10,000 tCO₂e in a given year must submit a report on their GHG emissions by June 1 of the following year. Facilities emitting less than the threshold can report voluntarily.

The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SOR-2018-66 (see footnote 106) include reporting requirements to improve emissions estimates. They include inventories of emitting components at upstream facilities; reports on volumes of gas vented, flared, and delivered off-site; and results of leak-detection-and-repair inspections and monitoring.

14. Measurement Frequency and Methods

Under Sections 67 and 79 of the Canada Oil and Gas Drilling and Production Regulations, 2009 (see footnote 108), flows and volumes are reported through daily drilling and production reports. In an emergency, the CER should be notified of the volume of gas flared or vented in the daily drilling report, daily production report, or in any other written or electronic form as soon as the circumstances permit. Provincial regulators have their own reporting requirements, which in many cases are more detailed.

15. Engineering Estimates

No evidence regarding federal engineering estimates could be found in the sources consulted. However, provincial regulators provide detailed guidance on metering and estimation methodologies. The ECCC provides detailed instructions on how to calculate GHG emissions, including from flares and vents, in its periodically updated guidance.

16. Record Keeping

According to the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SOR-2018-66 (see footnote 106), operators must maintain records that show that they have collaborated monitoring and leak detection devices. Provincial regulators provide detailed guidance on reporting and record-keeping requirements. Regulators may issue penalties for documents containing false or misleading information.

17. Data Compilation and Publishing

The National Pollutant Release Inventory is Canada’s legislated, publicly accessible inventory of pollutant releases. Its reports are published monthly and annually. Operators must prepare a complete inventory of pollutant release quantities and report emission sources to the National Pollutant Release Inventory if they exceed thresholds. Reporting is mandatory for facilities in the oil and gas sector that meet specified air contaminant threshold criteria. Reports for the previous year are due by June 1 of each year. Provincial energy and environmental regulators often have more detailed reporting on flared volumes and emissions available (see the chapters on Alberta, British Columbia, and Saskatchewan).

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

No monetary penalties or fees relate explicitly to gas flaring and venting at the federal level (although provincial regulators can impose such them). However, noncompliance with regulations and rules issued by the CER, which include reporting requirements on gas flaring and venting, can result in monetary penalties of up to Can$100,000 (about US$79,000 as of September 2021) a day per violation.
Canada: Federal

The violation of any specified provision of the Canada Oil and Gas Operations Act, 1999 (see footnote 109) or any of its regulations may result in a penalty. Such violations include failure to comply with any term, condition, or requirement of an operating license or authorization or any approval, leave, or exemption granted under the act. Under paragraph (7)(b), the penalty for a violation should not be more than Can$25,000 (about US$20,000 as of September 2021) for an individual and Can$100,000 (about US$79,000 as of September 2021) for any other entity.137 Compliance measures reported include a record of the sanctions imposed via a downloadable spreadsheet at both the federal and provincial levels. The CER website provides notices of noncompliance, orders, directions, and prosecution. The enforcement tool to complement other types of sanctions, such as monetary penalties, to provide regulatory agencies with an enforcement tool to complement other types of sanctions, such as monetary penalties.

Regulations (Federal-SOR/2016-25)136 establish administrative monetary penalties to provide regulatory agencies with an enforcement tool to complement other types of sanctions, such as monetary penalties. It also introduced minimum fines and increased maximum fines for serious offenses. The Environmental Violations Administrative Monetary Penalties Act, 2009139 details enforcement tools and penalty regime by adding ranges for fines tailored to different offenses. It also introduced minimum fines and increased maximum fines for serious offenses. The Environmental Violations Administrative Monetary Penalties Act, 2009139 details enforcement tools and penalty regime by adding ranges for fines tailored to different offenses. It also introduced minimum fines and increased maximum fines for serious offenses.

The Environmental Enforcement Act, 2010140 enhanced the enforcement tools and penalty regime by adding ranges for fines tailored to different offenses. It also introduced minimum fines and increased maximum fines for serious offenses. According to the Canada Oil and Gas Operations Act, 1999, the CER may suspend or revoke an operating license or an authorization for failure to comply with, contravention of, or default in respect of a fee or charge payable per the regulations made under Section 4 or a requirement undertaken in a declaration referred to in Subsection 5.11.

G. Enabling Framework

20. Performance Requirements

No evidence regarding federal performance requirements could be found in the sources consulted. However, provincial regulators provide detailed guidance on the performance of oil and gas operations, including flaring and venting.138

21. Fiscal and Emission Reduction Incentives

Resource owners in Canada (the federal or provincial government, private freehold owners, or First Nations) generate revenues primarily through royalties and taxes paid to them by developers from selling extracted oil and gas. Royalties can be up to 45 percent in federal offshore and offshore fields (see footnote 52). No evidence regarding federal fiscal and emission reduction incentives could be found in the sources consulted. However, provinces have fiscal incentive programs, such as royalty waivers, to induce gas capture, thereby reducing flaring and venting (see the chapters on Alberta, British Columbia, and Saskatchewan).

22. Use of Market-Based Principles

In December 2016, Canada’s First Ministers adopted the Pan-Canadian Framework on Clean Growth and Climate Change, setting a federal benchmark on carbon pricing for end-use fuels. The framework requires all provinces and territories to implement carbon pollution pricing systems by 2019. The federal legislation, the Greenhouse Gas Pollution Pricing Act, 2018141 introduced a carbon price of Can$10 (about US$7.9 as of September 2021) per tCO₂e on fuels, increasing to Can$30 (about US$24 as of September 2021) in 2021 and Can$50 (about US$39 as of September 2021) by 2022. This price applies in all provinces that do not set their own prices.

The federal carbon pricing regime does not cover all industries. Methane emissions from the oil and gas value chain, for example, are not universally covered, and some provinces have not adopted the federal carbon pricing benchmark. In 2019, Canada began designing the GHG offset program to encourage the cost-effective reduction of domestic GHG emissions or GHG removal projects from activities not covered by carbon pricing.141 The government issues offset credits only to projects that produce real, quantified, verified, and unique reductions in GHG. This offset program could provide incentives for upstream oil and gas producers to invest in offset projects.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

Market diversity and access is a crucial consideration for the Canadian oil industry. The Canadian natural gas market has been fully liberalized since gas prices were deregulated in 1985. Most oil and gas producers rely on pipelines and require provincial and federal policies that allow infrastructure to be built to deliver natural gas to new markets. A license from the appropriate provincial regulator must be obtained to construct and operate a pipeline. The CER, as the federal regulator, has jurisdiction if the pipeline crosses provincial or international boundaries. Federally regulated gas pipelines are generally considered to be contract carriers. The CER sets tariffs and the terms and conditions of access through regulation. The CER has the power to ensure that pipeline tolls are just and reasonable. Access to gas transmission is generally by agreement, but the CER has the power to direct a gas pipeline to provide any available capacity to a third party.

Canada: Alberta

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives


With the Pan-Canadian Framework on Clean Growth and Climate Change in 2016 (see footnote 104), Canada committed to reducing methane emissions from the oil and gas sector by 40–45 percent from 2012 levels by 2025. Alberta committed to reducing methane emissions from the oil and gas industry by 45 percent from 2014 levels146 to 2018, the ECC (see footnote 105) published Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SDIR-2018-66 (see footnote 106). Provinces can choose to adopt these regulations or draft their own to meet or exceed the stated targets. Section 10 of the Canadian Environmental Protection Act, 1999147 authorizes the minister of the environment and parks, known as the Alberta Environment and Parks (AEP), a governmental body, regulates air quality and is responsible for setting emissions and air quality standards under the Climate Change and Emissions Management Act, 2002.148 Flaring and venting are subject to gas emission limits and emission offsets to achieve reductions.

2. Targets and Limits

Directive 060, 2020, follows CASA recommendations; it defines limits on the total annual volume of gas flared, incinerated, and vented at all upstream wells and facilities. If flaring and venting of solution gas exceed the limit in any year, the AER will impose reduction limits for individual operating sites based on the analysis of the most recent annual data available.

Section 2.1 sets an annual solution gas flaring limit of 670 million m³. Acid gas volumes from gas sweetening (which are typically continuously flared) are excluded. Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period.

Per Section 2.3, the combined flaring and venting volume is limited to no more than 900 m³ a day. Operators must follow the decision tree approach recommended by CASA and demonstrate the feasibility of conservation options (see sections 12 and 21 of this chapter).

Section 8 sets an overall vented gas (routine and nonroutine) limit at a site of 15,000 m³ or 9,000 kilograms of methane a month. The limit on the volume of routinely vented gas at a site is 3,000 m³ or 1,800 kg of methane a month. Section 8.6 prescribes equipment-specific limits on venting.

Facilities that emit more than 100,000 tonnes of GHG a year are required to reduce their emissions intensity by 12 percent under the Climate Change and Emissions Management Amendment Act, 2003.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Responsible Energy Development Act, 2012150 created the AER from the existing Energy Resources Conservation Board. Several laws governing oil and gas activities in the province, including their conservation, lay the foundation for the AER’s regulation of flaring and venting along with the following other acts:

- the Alberta Mines and Minerals Act, 2000151
- the Oil and Gas Conservation Act, 2000152
- the Gas Resources Preservation Act, 2000153 and implementing regulations, Alberta Regulation 15/1: Oil and Gas Conservation Rules, 1977
- Oil Sands Conservation Act, 2000 (see footnote 149)

AER Directive 060, 2020 (see footnote 148) provides comprehensive guidance on flaring and venting. The requirements set forth in the directive are aligned with the Alberta Ambient Air Quality Objectives.154 Alberta Regulation 244/18: Methane Emission Reductions (see footnote 145) is an implementing regulation issued under the Environmental Protection and Enhancement Act, 2000.155 It applies to all upstream oil and gas facilities except processing plants approved under Section 15 of the Oil Sands Conservation Act, 2000.

The Climate Change and Emissions Management Act, 2003 (see footnote 156) created the framework for regulators setting limits and pursuing various strategies to reduce emissions. Emissions limits are regulated under the Technology Innovation and Emissions Reduction Regulation, 2019157 which superseded and replaced the Carbon Competitiveness Incentive Regulation, 2018.158 Companies have three ways to meet their reductions: make operating improvements, buy an Alberta-based credit (see section 22 of this chapter), or contribute to the Climate Change and Emissions Management Fund.

4. Legislative Jurisdictions

Alberta has jurisdiction over flaring, venting, and incineration, for which the province has comprehensive regulations. Emissions regulations are aligned with federal legislation and regulations.

5. Associated Gas Ownership

The ownership of oil and gas resources is split between the provincial government, the federal government, private freehold owners, and First Nations. Alberta owns about 80 percent of the mineral rights. The federal government owns 9 percent, including on most Indian reserves and national parks. The remainder is held privately under freehold ownership. The rights to explore, develop, and produce oil and natural gas, including associated gas, are transferred to participants through licenses.

C. Regulatory Governance and Organization

6. Regulatory Authority

The AER159 is the sole, independent regulator responsible for upstream oil, gas, and oil sands activities in the province, including flaring and venting. The AER’s governance structure is designed to provide both strong corporate oversight and independent supervision.
adjudication. The AEP[^165] regulates the air quality and emissions generated during oil and gas activities.

7. Regulatory Mandates and Responsibilities

At both the federal and provincial levels, the respective energy regulators have clearly defined responsibilities, with no overlapping or conflicting mandates. Agencies coordinate through collaboration.[^166] The AER’s statutory powers, mandates, and functions are governed by the Ministry of Energy, Ministry of Environment and Parks, and Ministry of Indigenous Relations.

The AER is responsible for environmental assessments of energy projects; the AEP is responsible for environmental assessments of non-energy resources. Environmental approvals are required if any substance that could harm the environment is released. All oil and gas activities receive such approval from the AER.

8. Monitoring and Enforcement

The enforcement mechanism is outlined in the AER’s Manual 013: Compliance and Enforcement Program, 2020[^167], which ensures enforcement of a risk-informed approach that balances compliance components: education, prevention, and enforcement.[^168] Numerous tools are available to the AER, including notices, warnings, orders, administrative sanctions, penalties, and prosecution. The AER has similar compliance enforcement tools. It also regularly publishes orders related to noncompliance.[^169]

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Section 3 of Directive 060, 2020 ("Temporary and Well Test Flaring and Incinerating", see footnote 148) does not require a permit for unplanned nonroutine flaring and incineration, such as during process upsets and emergencies. In addition, the AER does not require permits for flaring at oil and bitumen batteries. Under certain other conditions for example, compliance with the percentage of hydrogen sulfide limits or with the Alberta Ambient Air Quality Objectives, permits are not required. These conditions are confirmed by the decision-tree tool adopted from CASA recommendations (Section 3 of AER Directive 060, 2020).

10. Authorized Flaring or Venting

According to Section 3 of Directive 060, 2020, planned nonroutine flaring and incineration events require a temporary flaring or incineration permit from the AER, with advanced filing of proper documentation. Section 3 lists the conditions that require a temporary flaring permit and describes the requirements for obtaining the permit. All permit applications are published on the Public Notice of Application web page.[^170] The AER may issue a single "blanket" permit to cover several flaring events at different sites in an area if requested by the licensee. Companies may request a variance from the requirements if they have sufficient justification. Licensees must provide specific engineering, economic, and operational information to justify flaring or incinerating gas volumes above the volume allowance threshold. The AER does not consider venting an acceptable alternative to flaring or incineration (except for inert gases). It requires that gas be flared if gas volumes are sufficient to sustain stable combustion or conserved.

11. Development Plans

Directive 056: Energy Development Applications and Schedules, 2021[^171] presents the requirements and procedures for filing a license application to build or operate any petroleum industry on-site installations and the volume that is disposed of by burning in a flare or incinerator. Applicants proposing to flare, incinerate, or vent gas should comply with the requirements of Directive 060, 2020; and Section B of Alberta Regulation 151/71: Oil and Gas Conservation Rules, 1971 (see footnote 156).

Since 2018, management of fugitive emissions has been based on a systematic program of detecting and repairing leaks and malfunctioning equipment. The AER requires operators to develop and document a Methane Reduction Retrofit Compliance Plan containing a schedule to replace and retrofit existing equipment and allocating funding to reduce venting. The plan must set an overall limit on the volume of vented gas at all existing and future oil and gas sites by 2023.

12. Economic Evaluation

The framework for managing flaring and venting prescribed by Directive 060, 2020, Section 2 (Economic Evaluation of Gas Conservation, see footnote 148) requires firms to conduct an economic analysis following the decision-tree framework. All new and existing flares and vents must be evaluated, except for small intermittent sources (less than 100 m³ a month). Alberta has more than 450,000 oil wells of mainly lower productivity and a small number of large oil sands projects. A facility’s individual energy needs will determine the optimal utilisation strategy, how much associated gas it produces, and the well’s access to processing and pipeline infrastructure. The break-even economic criteria allow for the recovery of financing costs as well as capital and operating expenses. Conservation options include delivering gas to the market and using it on site as a fuel and for electricity generation and reservoir pressure maintenance. A conservation project is considered economic, and thus requires that the gas be conserved, if the net present value of the project before tax is greater than Can$50,000 (about US$39,500 as of September 2021). Every 12 months, licensees should update the conservation economics for any site that is flaring or venting a combined volume of more than 900 m³ a day. How much associated gas it produces, and the well’s access to processing and pipeline infrastructure. The break-

13. Measurement and Reporting

Some companies must accurately measure and report volumes of associated gas at all oil facilities, in accordance with Directive 060, 2020 (see footnote 148). Section 5 requires separate reporting of all monthly flared and vented volumes at gas plants. Flaring of sour gas must also be reported on the 5-30 Monthly Gas Processing Plant Sulphur Balance Report. According to Section B, the operator must include the following information in its annual methane emissions report:

- the volume of fugitive emissions by facility
- the corresponding mass of methane emitted by facility
- the type and date of survey
- the number of sources per site per facility.

The AER also requires a Fugitive Emissions Management Program following the survey and equipment guidance from the AER.[^170] The Fugitive Emissions Management Program should identify preventative maintenance practices; procedures for conducting surveys of fugitive methane emissions; screenings at a facility level (annually or three times a year depending on the type of facility or equipment); training programs; and procedures to track, manage, and verify the status of equipment repairs. Repairs to equipment with fugitive emissions must be made within 24 hours if the methane emissions cause an off-site odor, a pilot or ignition on a flare stack has failed, or the emissions pose a safety risk. Otherwise, the equipment must be repaired within 30 days, unless a shutdown is required to complete the repair. The emissions have a hydrocarbon concentration of 10,000 parts per million or less, or the source is a surface casing vent flow. The AER will consider innovative and science-based alternatives to the Fugitive Emissions Management Program. Alternative programs may incorporate the use of various technologies, such as unmanned aerial vehicles, vehicle-mounted sensors, and continuous monitoring devices to detect, track, repair, and report fugitive emissions (Section B of AER Directive 060, 2020).

14. Measurement Frequency and Methods

Most reporting is monthly. Section 2 of Directive 060, 2020 requires flared and vented solution gas to be reported monthly through Petrinex (Canada’s Petroleum Information Network). According to Section B of Directive 017, 2018 (see footnote 147), an annual methane emissions report must be submitted electronically to the AER by June 1 of the following calendar year. The first reporting period was 2019.
15. Engineering Estimates
According to Directive O77, 2018, measurements of continuous or intermittent flare and vent sources must be undertaken at all oil and gas facilities where annual average volumes per facility exceed 500 m³ a day, otherwise flare volumes can be estimated. Single-point measurement uncertainty must be ±0.5 percent, and monthly volume uncertainty must not exceed ±2.0 percent.

According to Section 5 of Directive O60, 2020 (see footnote 148), when metering is not required and is not carried out, engineering estimates must be used to report any flared gas that is not measured. According to Section 8, methane emissions may be quantified using continuous metering, periodic testing, or estimates based on accepted engineering practices.

According to Manual O15: Estimating Methane Emissions, 2020, emissions may be estimated using emission factors, the equations included within the manual, or engineering estimates as described in the Guide for Reporting to the National Pollutant Release Inventory. Any updates in Directive O60, 2020 or Directive O77, 2018, superseded the guidance in the manual.

16. Record Keeping
According to Section 10 of Directive O60, 2020, operators should maintain a log of flaring, incineration, and venting events and respond to public complaints. Records should be kept for at least 12 months. Section 8 requires operators to retain records of methane emissions for four years from the data they were created unless otherwise noted and provide them to the AER upon request. Section 5 requires gas plant operators to provide documentation for metering or estimating flared and vented gas volumes upon request from the AER.

17. Data Compilation and Publishing
The AER regularly publishes comprehensive reports on industry activity at daily, weekly, monthly, annual, and any other relevant frequency. For example, the ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data show historical data on crude oil and bitumen production from crude oil and bitumen batteries and flaring and venting at the batteries by location, type, and operator, they also indicate where the conservation of gas has been economically feasible. The AER also publishes monthly enforcement reports (ST108) and year-end reports (ST60B: Upstream Petroleum Industry Flaring and Venting Report). Reports include flared and vented volumes reported to the AER.

18. Monetary Penalties
AER Manual 013: Compliance and Enforcement Program, 2020 (see footnote 165) states that flaring, incinerating, and venting audits are required to ensure that flare systems are designed and operated appropriately and in accordance with approved conditions. The manual outlines the various tools available to the AER, including fines and monetary penalties. A schedule of fees can be found in Alberta Regulation 157/71: Oil and Gas Conservation Rules, 1971 (see footnote 156).

According to 244/18: Alberta Methane Emission Reductions Regulation, 2018 (see footnote 145), an operator that violates venting limits, reporting requirements, or any other obligations imposed by the AER (mainly via Directive O60) faces a maximum fine of Can$500,000 (about US$395,000 as of September 2021) for an individual and Can$500,000 (about US$395,000 as of September 2021) for a corporation.

The Alberta Administrative Penalty Regulation, 2003, is an implementing regulation of the Environmental Protection and Enhancement Act, 2000 (see footnote 158). The maximum administrative penalty that environmental regulators may impose is Can$5,000 (about US$3,950 as of September 2021) for each contravention or each day or part of a day on which the contravention occurs and continues.

19. Nonmonetary Penalties
Alberta’s legislation includes rising levels of sanctions depending on the seriousness of the violation, including production shut-in or suspension of application processing. Section 25 of the Oil and Gas Conservation Act, 2000 (see footnote 154) authorizes the AER to cancel or suspend a license or approval for a definite or indefinite period. In particular, the AER may suspend flaring permits for noncompliance. The AER’s decisions may be appealed under Section 36 of the Reasonable Environment Development Act, 2012 (see footnote 152).

The AER Compliance Dashboard provides a compliance history of companies since 2014. The dashboard is searchable. Between 2015 and mid-2021, it recorded 51 flaring violations. The AER handled almost all of them via notices of noncompliance or site inspections. Facilities are shut in if operators do not take corrective actions to comply with AER instructions within the time provided.

20. Performance Requirements
Section 7 of Directive O60, 2020 (see footnote 148) details performance requirements for flaring and venting. They apply to flares and incinerators—including portable equipment used for temporary operations—in all upstream oil and gas industry systems for combusting sweet, sour, and acid gas during activities that include well completion, servicing, and testing.

The AER has adopted CASA’s objective hierarchy and decision-tree framework for managing solution gas volumes and extended its application of the hierarchy to include flaring, incineration, and venting. The goal is to eliminate routine flaring, incineration, and venting. The objective hierarchy ranges from eliminating routine flaring, incineration, and venting of unburned gases to reducing the volume of such gas and improving the efficiency of the related systems.

21. Fiscal and Emission Reduction Incentives
In 1998, the government of Alberta announced the Otherwise Flared Solution Gas Royalty Waiver Program. Flaring gas that could economically be conserved makes the gas ineligible for a royalty waiver. The waiver is independent of the end-use of the gas and lasts for 10 years. Companies are also exempt from royalties if gas is used for on-site power generation. The gas royalty rate is 5 percent during the cost-recovery period, after which the royalty rate is a function of the reference gas price and production level.

According to Directive O60, 2020, gas conservation economies should account for royalties paid for incremental gas that would otherwise be flared or vented. If the economic evaluation results in a net present value of less than Can$5,000 (about US$4,000 as of September 2021), the operator should reevaluate the gas conservation project on a before-royalty basis. If the evaluation results in a net present value of Can$5,000 or more, the operator should proceed with the conservation project and apply to the AER for an ‘otherwise flared solution gas’ royalty waiver.

22. Use of Market-Based Principles
Alberta put a price on carbon emissions for large industrial emitters in 2007. It put a carbon levy on fuel from 2017 until its repeal in 2019. In December 2019, Alberta’s Technology Innovation and Emissions Reduction Regulation, 2019 (see footnote 159) set a price of Can$30 (about US$24 as of September 2021) per tCO2e on emissions from the oil and gas, electricity, cement, agriculture, and other sectors. The benchmark price rises to Can$40 (about US$32 as of September 2021) per tCO2e in 2019 and Can$50 (about US$39 as of September 2021) per tCO2e in 2022. This regulation meets the federal criteria.

The carbon price used to apply to facilities that had emitted 100,000 tCO2e or more a year in 2016 or subsequent years. An amendment in July 2020 allowed facilities that emit less to voluntarily comply with the regulation and reduce the administrative burden for regulated conventional oil and gas.
Canada: Alberta

facilities<sup>183</sup> in exchange for an exemption from Canada’s federal carbon price (see section 22 in the previous chapter). Also, firms are offering a lease-to-own program for nonemitting facility equipment. This program allows companies to voluntarily reduce emissions and generate carbon credits to pay down equipment leases.

23. Negotiated Agreements between the Public and the Private Sector

The AER allows flaring when conducted in accordance with Directive 060, 2020. However, an applicant for drilling and the landowner or land occupant may sign a zero-flaring agreement and file it along with the well application (Section 3.10). Once filed, the agreement becomes a condition of the well license. Should the licensee, operator, or approval holder fail to adhere to this agreement, operations at the well may be suspended. This agreement, including the condition, expires when production begins.

24. Interplay with Midstream and Downstream Regulatory Framework

AER regulations on flaring, venting, and emissions cover pipeline and storage facilities. Most oil and gas produced in Alberta is exported to other provinces or the United States via pipelines. Occasionally, an imbalance between demand and supply, bottlenecks in pipelines, or permitting delays can affect upstream operations. In 2018, for example, western Canadian oil supply outgrew the export pipeline capacity, resulting in record crude price differentials. Alberta’s government mandated a production curtailment effective January 2019, later extended to December 31, 2020. Such a curtailment would likely reduce emissions from associated gas flaring but only temporarily.

Canada: British Columbia

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

In 2016, British Columbia introduced regulations to eliminate routine flaring at oil and gas production facilities, following the province’s 2007 energy plan. British Columbia’s production of liquid fuels (including oil, condensate, and pentanes plus) accounts for less than 2 percent of Canadian liquids production. Gas production in British Columbia accounts for nearly 30 percent of total gas production in Canada. Oil production declined to roughly one-fourth its level in the early 2000s, but production of condensate increased, along with natural gas production from the unconventional Montney play in the province’s northeast.

Gas production increased by a factor of 2.5 over 20 years; flaring volume decreased by approximately a third, accounting for 6 percent of GHG emissions from British Columbia’s upstream oil and gas sector.<sup>185</sup>

As part of the 2016 Pan-Canadian Framework on Clean Growth and Climate Change (see footnote 104), the government of Canada committed to reducing methane emissions from the oil and gas sector by 40–45 percent by 2025 from 2012 levels. British Columbia committed to reducing fugitive and vented methane emissions by 45 percent by 2025 from 2014 levels (Clean BC Plan).<sup>186</sup>

In 2018, the ECCC (see footnote 105) published SOR-2018-66, entitled ‘Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) Do Not Apply in British Columbia.’<sup>187</sup>

Section 10 of the Canadian Environmental Protection Act, 1999 (see footnote 144) authorizes the minister of the environment to defer to “equivalent” regulations promulgated by a provincial government. In April 2020, an equivalency agreement between federal and British Columbia regulations was published.<sup>188</sup> Accordingly, the federal government exempted British Columbia from federal regulation via SOR/2020-60, entitled ‘An Order Declaring that the Provisions of the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) Do Not Apply in British Columbia.’<sup>189</sup>

2. Targets and Limits

The cumulative volume of flaring authorized for well workover or maintenance operations cannot exceed 50,000 m<sup>3</sup> in a year. There are also various limits on flared volumes that trigger different reporting. British Columbia’s new methane regulations are designed to reduce methane emissions by 10.9 million tCO<sub>2</sub>E over a 10-year period starting in 2020.<sup>190</sup>

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Together with the Ministry of Energy, Mines and Petroleum Resources and the Climate Action Secretariat of the Ministry of Environment and Climate Change Strategy, the BCOGC has developed the Flaring and Venting Reduction Guideline, 2018 (see footnote 186). This guideline covers flaring, incinerating, and venting and includes guidance on flare approval requests; dispersion modeling; and the measuring and reporting of flared, incinerated, and vented gas. The guideline contains methane emission regulations to address the following primary sources of methane from the upstream oil and gas industry: pneumatic devices, equipment leaks, compressor seals, glycol dehydrators, storage tanks, and surface casing vents. The guideline aims to meet methane emission reduction targets and ensure that they are equivalent to federal regulations and targets. British Columbia’s carbon tax is applied to these emissions for the first time.

Canada: British Columbia

The following provincial laws govern the exploration for and production of oil and natural gas in British Columbia:

- the Oil and Gas Activities Act, 2008 190
- the Petroleum and Natural Gas Act, 1996 191
- the Environmental Management Act, 2003 192
- the Climate Change Accountability Act, 2007 (formerly GGRTA) 193
- the Clean Energy Act, 2010 194

For large oil and gas operations, the BCOGC issues site-specific air discharge permits under the Environmental Protection and Management Regulation, 2010 195 Each permit contains requirements for limiting the release of air contaminants such as carbon monoxide, sulfur dioxide, oxides of nitrogen, hydrocarbons, carbon monoxide, and particulate matter. Requirements limiting air contaminants for smaller operations are specified in the Oil and Gas Waste Regulation, 2000 196 and the Drilling and Production Regulation, 2010 197 Other relevant secondary legislation includes the Administrative Penalties Regulation, 2011 198 and the Carbon Neutral Government Regulation, 2008 199.

4. Legislative Jurisdictions

British Columbia has jurisdiction over flaring, venting, and incineration, for which the province has comprehensive regulations. Emissions regulations are aligned with federal legislation and regulations.

5. Associated Gas Ownership

The ownership of oil and gas resources is split between the provincial government, the federal government, private freehold owners, and First Nations. The rights to explore for, develop, and produce oil and natural gas, including associated gas, are transferred to operators through licenses or leases.

C. Regulatory Governance and Organization

6. Regulatory Authority

The BCOGC is the sole provincial regulatory agency responsible for overseeing oil, gas, and geothermal operations as defined by the Oil and Gas Activities Act, 2008 (see footnote 190). It is governed by a board of directors that sets the strategic direction and establishes accountability and transparency, including corporate risks, as part of the strategic planning process. The board has the power to create regulations concerning oil and gas activities. The BCOGC, in consultation with stakeholders, monitors progress to reduce the volume of solution gas that is flared or vented.

7. Regulatory Mandates and Responsibilities

The BCOGC and the CER (the federal regulator) have clearly defined responsibilities, with no overlapping or conflicting mandates. The BCOGC regulates flaring and venting activities in the province. The Environmental Assessment Office, a regulatory agency within the provincial government, manages environmental assessments.

8. Monitoring and Enforcement

The BCOGC has the authority to inspect, audit, and enforce compliance with laws and regulations, and sanction noncompliance under several laws (see sections 18 and 19 of this chapter). It publishes the results of inspections, tickets and fines, warning letters, enforcement orders, and contravention decisions on the Compliance and Enforcement website. 200

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

British Columbia’s Flaring and Venting Reduction Guideline, 2018 (see footnote 186) does not allow routine venting. If gas volumes are sufficient to sustain stable combustion, the gas should be flared or conserved. If venting is the only feasible alternative, it should meet the following requirements, set out in Section 7 of the guideline:

- All continuous and temporary venting and their sources must be evaluated using the vent evaluation decision tree.
- Permit holders must burn all nonconserved volumes of gas if volumes and flow rates are sufficient to support stable combustion.
- The quantity and duration of vented gas must be minimized.
- A permit holder must have an adequate program for managing fugitive emissions.

According to Section 1 of the guideline entitled “Approvals and Notifications for Non-Conserving Facilities,” nonroutine flaring (such as for maintenance and emergencies) does not require a specific approval but may be subject to limitations specified in the facility permit. Permit holders should notify residents and the BCOGC of nonroutine flaring at facilities.

10. Authorized Flaring or Venting

Section 2 of the Flaring and Venting Reduction Guideline, 2018 on temporary flaring approval for well testing, states that flaring for purposes other than those previously specified (in Section 4), including well testing, must be approved in the facility permit. Approval to flare may be requested in the well permit application or by amending the well permit.

The Drilling and Production Regulation, 2010 (see footnote 197) authorizes flaring at wells if the flaring is in line with the well’s permit or is related to drilling operations and is necessary because of an emergency. Flaring is also authorized for well workover or maintenance operations and when the cumulative quantity of flared gas does not exceed 50,000 m³ a year. Section 43 of the Drilling and Production Regulation, 2010, on flaring notification and reporting, requires a permit holder to notify the BCOGC at least 24 hours before a planned flaring event if the quantity of gas to be flared exceeds 10,000 m³. If an unplanned flaring event occurs and the amount of flared gas exceeds 10,000 m³, the permit holder should notify the BCOGC within 24 hours.

11. Development Plans

No evidence regarding development plans could be found in the sources consulted.

12. Economic Evaluation

Section 5 of the Flaring and Venting Reduction Guideline, 2018, on economic evaluation of gas conservation, is similar to Section 2 of Alberta’s Directive 060 (see section 12 of the chapter on Alberta). British Columbia’s guidance considers a solution gas conservation project with a net present value of less than Can$55,000 (about US$43,400 as of September 2021) uneconomic. The project economics should be reevaluated annually (within 12 months of the last evaluation) using updated prices, costs, and forecasts.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Chapter 10 of the Flaring and Venting Reduction Guideline, 2018 (see footnote 186) states the requirements for measuring and reporting volumes of gas flared, incinerated, or vented. These requirements are in addition to the requirements specified in the Measurement Guideline for Upstream Oil and Gas Operations, 2020 201; Oil and Gas Activity Operations Manual, 2020 202; the Oil and Gas Royalty Handbook, 2014 203; and the Drilling and Production Regulation, 2010 (see footnote 197). Permit holders of oil and natural gas production and processing facilities must report volumes of gas greater than or equal to 100 m³ a month that are flared, incinerated, or vented. These volumes are to be reported through the BC-S2 or BC-19 forms of the Ministry of Finance. All flaring, incinerating, and venting from routine operations; emergency conditions; and depressurizing pipelines, compressors, and processing systems must be disclosed. Gas used for a pilot, a purge, or a blanket must be reported as either flared or vented.
Canada: British Columbia

The Greenhouse Gas Emissions Reporting Regulation, 2015, details the conditions and criteria for the mandatory reporting of GHG emissions by operators. Operators that emit more than 10,000 tCO2e a year must collect and report data on their emissions to the BCOGC. Submissions must be based on a process-flow diagram and include emissions from flaring, venting, and other fugitive emissions. The regulation also establishes verification bodies to evaluate reports from operators.

14. Measurement Frequency and Methods
Chapter 10 of the Flaring and Venting Reduction Guideline, 2018, requires permit holders to demonstrate that gas volumes are determined accurately and reliably. They must have written documentation detailing the methodology used to determine flared, incinerated, and vented gas volumes for all their wells, pipelines, and facilities that must be available for review by an official.

Meters designed for expected flow conditions and range must be used to measure continuous or nonroutine flare and vent sources at oil and gas production and processing facilities at which the total volumes of gas flared, incinerated, and vented per facility exceed 500 m³/day (excluding dilution gas) on an annual average basis. Chapter 2 of the Measurement Guideline for Upstream Oil and Gas Operations, 2020, provides details regarding calibration and proving the accuracy of measurement devices.

15. Engineering Estimates
Section 10 of the Flaring and Venting Reduction Guideline, 2018, states that the BCOGC will accept flared, incinerated, and vented gas estimates if measurement is not stated as a requirement. The operator’s estimates should account for all gas flared, incinerated, and vented at their facilities (as estimated to the nearest 100 m³/month) during routine, emergency, and maintenance operations, including emissions while depressurizing vessels, compressors, and pipelines. Volume estimates should be based on engineering calculations. The BCOGC recognizes the Canada Association of Petroleum Producers’ Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, 2002, as containing acceptable practices for estimating.

16. Record Keeping
Section 10 of the Flaring and Venting Reduction Guideline, 2018, requires permit holders to produce documentation describing estimation of the volume of flared and vented gas and reporting procedures as well as operating logs if requested by the BCOGC. The documentation provided should include assumptions, mathematical formulas, estimation methodologies, and details on the means used to obtain and update input data. Permit holders should maintain a log for a minimum of 12 months of flaring and venting events and respond to any public complaints.

17. Data Compilation and Publishing
The BCOGC publishes monthly and annual flaring data on its website in the Air Summary Report – Flaring Data. The reports can be downloaded from the BCOGC website, which also has a range of other publications, tools, and data sets designed to inform and educate the general public, First Nations, communities, and government officials.

F. Fines, Penalties, and Sanctions
18. Monetary Penalties
The Administrative Penalties Regulation, 2011 (see footnote 198) establishes that a person who contravenes various responsibilities related to flaring and venting (Sections 41-44 of the Drilling and Production Regulation, 2010) is subject to fines ranging from Can$20,000 (about US$16,000 as of September 2021) to Can$250,000 (about US$200,000 as of September 2021). The documentation provided should include assumptions, mathematical formulas, estimation methodologies, and details on the means used to obtain and update input data. Permit holders should maintain a log for a minimum of 12 months of flaring and venting events and respond to any public complaints.

19. Nonmonetary Penalties
The BCOGC also uses the following tools to sanction operators that do not comply with laws and regulations:

- Orders are issued if there is a failure to comply with the Oil and Gas Activities Act, 2008 (see footnote 190), associated regulations, permits or authorizations, or a previous order.
- Tickets are issued under the authority of provincial acts for which the BCOGC has regulatory responsibility, including the Water Sustainability Act, 2014, and the Forest Act, 1996.
- Charges are recommended to the Crown Counsel for prosecution and possible court action.

20. Performance Requirements
Section 44 of the Drilling and Production Regulation, 2010 (see footnote 197) sets performance standards for the flare stacks operated by permit holders of a well or a facility. It also specifies the measures to be considered if the hydrogen sulfide content of the gas to be flared exceeds 1 mole percent. Flare and incinerator systems installed after the date the regulation came into force must be designed and operated within limits specified by a professional licensed or registered engineer. Flaring should not result in the emission of black smoke. Section 2.6, “Site-Specific Requirements Related to Well Flaring,” and Chapter 6, “Performance Requirements,” of the Flaring and Venting Reduction Guideline, 2018 (see footnote 186) provide additional information.

21. Fiscal and Emission Reduction Incentives
British Columbia has fiscal incentives in place to induce the lease use or marketing of associated gas. There are two broad classifications for calculating natural gas royalties: conservation gas and nonconservation gas. Conservation gas is natural gas that has been produced as part of oil production that is conserved and marketed instead of flared. All other gas is considered nonconservation gas. Section 5 of the Oil and Gas Royalty Handbook, 2014, shows how royalties are calculated under various gas prices and well classifications. Royalties paid for conservation gas are often as low as 8 percent, compared with up to 27 percent for nonconservation gas. This difference in royalty rates creates an incentive for producers to capture and market associated gas.

22. Use of Market-Based Principles
In 2008, British Columbia implemented the Carbon Tax Regulation. The tax applies to the purchase and use of fossil fuels burned for transportation, home heating, and electricity. It covers approximately 70 percent of provincial GHG emissions. The impact of the tax on consumers is compensated for by a reduction in personal and corporate income taxes by an approximately equal amount. The carbon tax increased gradually from Can$10 (about US$7.9 as of September 2021) per tCO2e in 2008 to Can$30 (about US$24 as of September 2021) per tCO2e in 2012, at which point the government froze the rate at Can$30 per tCO2e until further notice. The carbon tax was increased to Can$40 (about US$32) per tCO2e in April 2019. In 2019, it rose to Can$440 (about US$332) as of September 2021 per tCO2e, which for natural gas corresponds to Can$0.076 per m³. In response to COVID-19, the carbon tax will remain at its current level until further notice.

The Ministry of Environment and Climate Change Strategy has been managing a carbon offset program since 2010. In the oil and gas sector, offset projects have reduced flaring or venting, typically by using gas for electricity generation.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.
Canada: British Columbia

24. Interplay with Midstream and Downstream Regulatory Framework

Most gas production in British Columbia is exported to other provinces or the United States via pipelines. Gas production increasingly comes from remote unconventional plays (reservoirs), such as Montney and Horn River in the northeast corner of the province, which are far from consuming regions. The coordination of drilling activity with the development of sufficient midstream capacity can avoid bottlenecks in transport capacity and hence reduce flaring. The regulator encourages producers and third parties to pursue such coordination of midstream capacity and new production.

Canada: Saskatchewan

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Saskatchewan accounts for nearly 30 percent of liquids production in Canada. Gas production is associated mostly with gas from oil wells; it accounts for only 2–3 percent of total Canadian production. Associated gas production was rising until 2020, along with increased oil activity.

The largest GHG sources in Saskatchewan are emissions from flaring and venting during oil, natural gas, and coal and oil sands mining operations. They account for approximately 17 percent of total emissions in the province (see footnote 107). Between 2005 and 2018, overall GHG emissions in Saskatchewan increased by 12 percent, or 8.9 million tCO₂e, while the amount of GHG emissions from associated gas decreased as part of the 2016 Pan-Canadian Framework on Clean Growth and Climate Change (see footnote 104).

As part of the government of Canada committed to reducing methane emissions from the oil and gas sector by 40–45 percent from 2012 levels by 2025. The Saskatchewan government committed to reducing GHG emissions from flaring and venting in the province’s upstream oil and gas sector by 40–45 percent of the 2015 levels as part of the province’s Methane Action Plan.216

As of January 2020, the Saskatchewan government introduced the O-2 Reg 7: Oil and Gas Emissions Management Regulations, 2019, to reduce GHG emissions from flaring and venting in the upstream oil and gas sector, including the Oil and Gas Emissions Management Regulations, 2019.217 Directive PNG036: Venting and Flaring Requirements, 2019,218 and Directive PNG017: Measurement Requirements for Oil and Gas Operations, 2015.219

Section 50 of the Canadian Environmental Protection Act, 1999 (see footnote 144) authorizes the minister of the environment to defer to equivalent regulations promulgated by a provincial government. In May 2020, the federal government concluded that the Saskatchewan regulations would not be equivalent to federal regulations, mainly because the latter fixed the emission intensity limits after 2025 with no further reduction required. As the equivalency agreement between the government of Canada and the government of Saskatchewan terminates at the end of 2024, the government of Saskatchewan will have to introduce additional regulatory measures for a new equivalency agreement to be concluded beyond 2024.220

2. Targets and Limits

Directive PNG036: Venting and Flaring Requirements, 2019, imposes several restrictions on flaring and venting:

- Section 5.1 states that oil wells and facilities that flare and vent a combined volume of associated gas greater than 900 m³ a day should flare all nonconserved associated gas unless it must be vented to avoid emergencies. All existing oil wells or oil facilities should comply by July 1, 2020. All new wells must comply immediately.
- Section 5.2, on “Associated Gas Venting,” states that no operator should vent any volume of gas from a well or facility that contains hydrogen sulfide in a concentration greater than 10 mole per kilomole of gas, cause off-lease odors, or exceed Saskatchewan Ambient Air Quality Standards.221

The O-2 Reg 7 Oil and Gas Emissions Management Regulations, 2019, aim to reduce methane emissions in the province by more than 40 percent between 2020 and 2025. Table 2 (Appendix) limits...
Canada: Saskatchewan

the methane emission intensity by production class and year, starting in 2020 and ending in 2030. An Emissions Reduction Plan is due if the combined potential annual emissions are higher than 50,000 tCO2e, calculated by Saskatchewan’s Ministry of Energy and Resources (MER) based on government data or Integrated Resource Information System (IRIS) reporting information.

B. Legal, Regulatory Framework, and Contractual rights

3. Primary and Secondary Legislation and Regulation


Directive PNG017: Measurement Requirements for Oil and Gas Operations (see footnote 219) details how fuel gas, vented gas, and flared gas are measured for accounting and reporting purposes in Saskatchewan. It also requires enhanced quantification of associated gas at heavy-oil facilities. Directive PNG032: Volumetric, Valuation, and Infrastructure Reporting in Petrinex227 provides guidance on reporting volumes in Petrinex.

Directive S-20: Saskatchewan Upstream Flaring and Incineration Requirements, 2019,228 applies company-level GHG emissions intensity limits to venting emissions from oil facilities. The Oil and Gas Emissions Management Regulations, 2019 (see footnote 216) require mandatory results-based methane emissions reduction at the company level, not at the level of individual facilities or pieces of equipment.

4. Legislative Jurisdictions

Saskatchewan has jurisdiction over flaring, venting, and incineration, for which the province has comprehensive regulations. Emission regulations are aligned with federal legislation and regulations.

5. Associated Gas Ownership

Ownership of oil and gas is split between the provincial government, the federal government, private freehold owners, and First Nations. The rights to explore for, develop, and produce oil and natural gas, including associated gas, are transferred to participants through licenses or leases.

C. Regulatory Governance and Organization

6. Regulatory Authority

The MER228 is the primary regulatory authority for the oil and gas industry. It develops and implements policies and programs to promote responsible growth and development of the province’s natural resources.

7. Regulatory Mandates and Responsibilities

The MER is responsible for regulating licensees of oil and gas wells and facilities and managing flaring and venting in accordance with Directive PNG036: Venting and Flaring Requirements, 2019 (see footnote 218). It is responsible for gathering and analyzing data, reporting requirements for flaring reduction, compliance, and enforcement.

The environmental screening process for oil and gas exploration and development activities is outlined in the Environmental Review Guidelines for Oil and Gas Activities.229 They clarify which branch of the Saskatchewan Ministry of Environment should be contacted first.

8. Monitoring and Enforcement

Directive PNG076: Enhanced Production Audit Program, 2016,230 describes the procedures of the province’s audit program for the oil and gas industry. Section 15 of the Oil and Gas Emissions Management Regulations, 2019 (see footnote 217) empowers the minister to audit and reporting of volumes of associated gas at oil facilities of the licensee at any time to determine whether the measurement and reporting comply with the act, implementing regulations, and any applicable directives. Section 10 of the Oil and Gas Conservation Regulations, 2012 (see footnote 226) provides that the minister may issue administrative penalties (see sections 18 and 19 of this chapter).

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

The Oil and Gas Conservation Regulations, 2012 (see footnote 226) stipulate that gas flared or vented at an oil well or facility should not exceed 500 m³ a day unless it is an emergency and a reasonable level of precaution has been taken to protect human health, public safety, property, and the environment. Section 6 of Directive PNG036: Venting and Flaring Requirements, 2019 (see footnote 218) states that gas venting from a well or facility, including gas plants, is permitted unless there is an emergency and venting is required to protect human health, public safety, property, or the environment, including prevention of a fire or explosion.

10. Authorized Flaring or Venting

Operators of oil wells and facilities are authorized to flare all nonconserved gas volumes of more than 900 m³ a day if they meet the requirements of Directive S-20: Saskatchewan Upstream Flaring and the Incineration Requirements, 2019 (see footnote 228). However, if flared volumes exceed 900 m³ a day, and the flare is within 500 meters of an occupied dwelling, public facility, or an urban center, the gas should be conserved unless the operator obtains consent from the occupants or approval from the regulator.

11. Development Plans

No evidence regarding development plans could be found in the sources consulted.

12. Economic Evaluation

Section 50 of Part VIII, ‘‘Production Operations,’’ of the Oil and Gas Conservation Regulations, 2012 (see footnote 226) states that for conservation purposes, the minister may require the operator of an oil well to collect and either use or sell the gas produced. Section 50 states that the minister may require the operator to analyze gas composition. If a product is present in a quantity that can be economically extracted, the minister may require the product’s separation, conservation, and utilization.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Directive PNG017: Measurement Requirements for Oil and Gas Operations, 2015 (see footnote 219) provides the regulatory requirements for the measurement, accounting, and reporting of flaring and venting across a variety of oil and gas operations, including flaring and venting at various sites. Directive PNG032: Volumetric, Valuation, and Infrastructure Reporting in Petrinex, 2016 (see footnote 227) require all operators to provide well and facility infrastructure information, monthly pipeline split, and volumetric and valuation information electronically via the website of Petrinex.233 This requirement is stipulated in Section 66 of the Oil and Gas Conservation Act, 1976 (see footnote 225) and Section 3 of the Petroleum Registry and Electronics Documents Regulations, 2012.234 Directive PNG032 also requires all emissions to be calculated and expressed in CO2e. Directive PNG076: Enhanced Production Audit Program, 2016 (see footnote 231) sets out the requirements
Canada: Saskatchewan

for operators to declare the degree to which they have the infrastructure in place to ensure compliance with the regulator’s measurement and reporting requirements.

14. Measurement Frequency and Methods

Directive PNG017: Measurement Requirements for Oil and Gas Operations, 2015 (see footnote 219) provides regulatory requirements with respect to measurement points used for accounting and reporting purposes. It specifies what volumes must be measured and how (including estimation methods), the volumes to be reported to the regulator, the accounting procedures to determine those volumes, and the data to be kept for auditing. The principal measurement technologies and procedures include, among others, meters for flow volumes, calculated volumes using a proration formula based on test volumes, estimates of volumes based on production facility and product characteristics, and gauge boards for tanks. The directive provides “standards of accuracy for gas and liquid measurement that take into account potential impacts to royalty, equity, reservoir engineering, declining production rates, aging equipment, environment, public safety, accuracy and completeness.”

There are detailed guidelines specifically for venting from different facilities in Guideline PNG035: Estimating Venting and Fugitive Emissions, 2019.238 An Excel-based gas estimation tool has been developed to aid operators in estimating vent volumes consistently and accurately.239 There are also special guidelines for heavy-oil projects.240

15. Engineering Estimates

Section 4 of Guideline PNG035: Estimating Venting and Fugitive Emissions, 2019, allows the use of vent gas factors or engineering estimates unless an operator is otherwise required to meter or test, as per Directive PNG017: Measurement Requirements for Oil and Gas Operations, 2015.

16. Record Keeping

Section 9 of Directive PNG016: Venting and Flaring Requirements, 2019 (see footnote 216) states that the licensee should maintain a log of flaring and venting events and respond to public complaints. The log should:
• include information on complaints related to flaring and venting events and their resolution
• describe each nonroutine flaring and venting incident and any changes implemented to prevent future nonroutine events
• include the date, time, duration, gas source, hydrogen sulfide concentration, and volumes of each incident
• keep records for a minimum of 12 months.

Flaring and venting records should be made available to the MER upon request. Everyone who submits a report or return following Section 29 of the Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations, 2019,177 should retain all documents, methodologies, and information used to prepare the report for a minimum of seven years.

17. Data Compilation and Publishing

The MER publishes monthly Natural Gas Volume and Value Summary reports.218 Reports detailing the gas produced from wells, total gas production, gas flared or vented, and gas available for use or sale can also be downloaded. Under Section 20 of the Oil and Gas Emissions Management Regulations, 2019 (see footnote 217) the minister is required to publish an annual report setting out:
• the total of combined emissions at all oil facilities in Saskatchewan
• the total of combined potential emissions at all oil facilities in Saskatchewan
• the emissions for all oil facilities that are licensed by each licensee for the year.

Starting in 2021, the government of Saskatchewan will release an annual progress report on all commitments, targets, programs, and policies listed in the Methane Action Plan.219

18. Monetary Penalties

Section 10 of the Oil and Gas Conservation Regulations, 2012 (see footnote 226) provides that the minister may issue administrative penalties if an operator exceeds the combined emissions limit at its oil facilities according to the formula defined in the regulations. The operator may apply to the minister within 30 days of receipt of the assessment notice to defer payment of all or part of the assessed penalty.

The Oil and Gas Emissions Management Regulations, 2019 (see footnote 216) set out the penalties for failing to comply with the regulations and directives with respect to submitting the information in Table 1 of Part III of the Appendix. Section 10 states that the minister may impose a penalty on a company whose oil facilities produce, in any year, combined emissions that exceed the limit determined in the regulations calculated using the formula $A = B × C$, where $A$ is the total penalty to be paid; $B$ is the amount by which the combined emissions exceed the combined emissions limit, expressed in tCO₂e and calculated for the year in accordance with subsection 11; and $C$ is the dollar amount per tonne of excess emissions set out in Table 3 of the Appendix. The penalty per tCO₂e increases every year until 2024, when the unit penalty is fixed in nominal terms (Table 3 in Appendix)

If a correction results in a change in the combined emissions for a license on December 31 of the year for which the combined emissions are calculated, the licensee is required to pay within the period specified by the minister, a penalty on any amount by which the combined emissions at the oil facilities exceed the limit on combined emissions, calculated in accordance with Subsection 11, plus interest, calculated at a rate of 10 percent a year. This payment is in addition to any penalty already paid for that year.

Section 13 of Directive PNG017: Enhanced Production Audit Program, 2016 (see footnote 231) states that if a declaration is not submitted via Petrinex, the Petrinex error EPP001 will trigger a penalty in accordance with the Oil and Gas Conservation Regulations, 2012. Penalties can also be charged for failing to promptly submit the documentation requested by the regulator.

19. Nonmonetary Penalties

Part XII of the Oil and Gas Conservation Regulations, 2012, authorizes the minister to suspend or shut down wells and other production facilities and seal any meter valves.

20. Fiscal and Emission Reduction Incentives

Associated gas that is flared or vented within permitted levels is not subject to royalties. According to the Administrative Procedures Related to Associated Gas Royalties/Taxes243 and Crude Oil and Natural Gas Royalty/Tax Factors Information Circulars,232 companies are exempt from royalties if royalties make gas production uneconomic. In addition, any gas used for on-site power generation is exempt from royalties. The gas royalty rate may be as high as 12 percent, depending on the type of gas well and the production rate of the well. Saskatchewan is launching a new Associated Gas Conservation Program to create more opportunities in the upstream sector for the sale and movement of methane between oil production facilities for on-site use.

The Saskatchewan Petroleum Innovation Incentive244 provides a royalty credit for commercial innovation projects new to Saskatchewan that can better manage GHG emissions. The Oil
Canada: Saskatchewan

and Gas Processing Investment Incentive offers transferable royalty or freehold production tax credits at a rate of 15 percent of eligible program costs to value-added projects across all oil and gas industry segments such as gas-gathering transportation infrastructure and methane gathering projects. The Oil and Gas Conservation Regulations, 2012 (see footnote 226) allow operators to build pipelines to capture associated gas as qualifying conservation projects to avoid paying penalties.

22. Use of Market-Based Principles

The 2016 Pan-Canadian Framework on Clean Growth and Climate Change set a federal benchmark, requiring all provinces and territories to implement carbon pollution pricing systems by 2019. Saskatchewan’s system for large GHG emitters started in January 2019. The federal pricing system is being applied to electricity generation and natural gas transmission pipelines.

23. Negotiated Agreements between the Public and the Private Sector

The Saskatchewan Petroleum Industry/Government Environment Committee was formed in 1992 to respond to the need for the government and industry to work cooperatively to resolve provincial environmental management issues. The provincial government agencies represented include the Ministry of Environment, the MER, and the Ministry of Agriculture, on a project-specific or issue-specific basis. Several industrial associations are also represented. The committee addresses matters including climate change, flaring and venting, remediation guidelines, and management standards.

24. Interplay with Midstream and Downstream Regulatory Framework

Many of the regulations on flaring, venting, and emissions cover pipeline and storage facilities. Most oil production in Saskatchewan is exported to other provinces or the United States via pipelines. The gaps in the synchronization of drilling activity with the development of sufficient gas midstream capacity can create bottlenecks and lead to increased flaring or venting.

### Colombia

**0.33 billion cubic meters of gas flared in 2021**
(total oil production 737 thousand barrels per day)

<table>
<thead>
<tr>
<th>Change in Flare Gas Volumes*</th>
<th>Change in Flare Gas Intensity**</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>2015-2020</td>
</tr>
<tr>
<td>-60%</td>
<td>-52%</td>
</tr>
<tr>
<td>2015-2021</td>
<td>2015-2020</td>
</tr>
<tr>
<td>-46%</td>
<td>-39%</td>
</tr>
</tbody>
</table>

* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 6 Gas flaring volume and intensity in Colombia, 2012–21

Note: Data shown is from the report based on data submitted by the Global Gas Flaring Reduction Partnership (GGFR) using verified data from the Colombian School of Mines. The approach is applied to all countries covered in this report in a consistent manner.

This approach is applied to all countries covered in this report in a consistent manner.

In 2020, Ecopetrol endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). Colombia also participates in the Global Methane Initiative (n.d.; see footnote 30). At the end of 2020, Colombia submitted an updated NDC to the UNFCCC, increasing its commitment to reducing GHG emissions by 2030 from 20 percent to 51 percent, albeit from a slightly higher business-as-usual scenario emission level. The new 2030 target for GHG emissions is 169 million tCO₂e, down from 265 million tCO₂e in the original NDC submitted in 2018.

### A. Policy and Targets

1. **Background and the Role of Reductions in Meeting Environmental and Economic Objectives**

   The volume of gas flared in Colombia declined by almost 70 percent, from 1 bcm in 2012 to 0.3 bcm in 2021 (figure 6). Oil production also declined but by only one-fifth. The flaring intensity declined steadily year after year during this period. There were 43 individual flare sites in the last flare count, conducted in 2019.

   In 2020, Ecopetrol endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). Colombia also participates in the Global Methane Initiative (n.d.; see footnote 30). At the end of 2020, Colombia submitted an updated NDC to the UNFCCC, increasing its commitment to reducing GHG emissions by 2030 from 20 percent to 51 percent, albeit from a slightly higher business-as-usual scenario emission level. The new 2030 target for GHG emissions is 169 million tCO₂e, down from 265 million tCO₂e in the original NDC submitted in 2018. Many mitigation measures are proposed across all sectors of the economy, including reducing fugitive emissions across the oil and gas sector and using natural gas instead of coal.

   In 2010, Ecopetrol launched its current climate change strategy, which includes monitoring and reporting GHG emissions, reducing emissions from the company’s operations and supply chain, engaging in research and development, and contributing to the national climate policy. The company developed a work plan to reduce flaring by 8 million tCO₂ by 2021 and carried out some projects to reduce methane leaks from its equipment. Ecopetrol is also seeking to reduce emissions from its operations by 20 percent by 2030 from the 2010 level. Emissions from flaring represent a small share of Ecopetrol’s emissions, but venting and fugitive emissions remain significant.

   Over the past decade, re-injection of gas for enhanced oil recovery has decreased from more than 80 percent of gas volumes to about 50 percent, to increase the availability of natural gas in the domestic market. In August 2021, the Ministry of Mines and Energy (MME) released a new resolution for public consultation on the use, flaring, and venting of natural gas, and detection and prevention of fugitive emissions during upstream oil and gas activities. As a result, MME Resolution 40066/2022 was released on February 11, 2022, making Colombia one of the first countries to adopt specific regulation covering the control and reduction of fugitive methane emissions in addition to flaring and venting.

2. **Targets and Limits**

   No evidence regarding targets and limits could be found in the sources consulted.

### B. Legal, Regulatory Framework, and Contractual rights

3. **Primary and Secondary Legislation and Regulation**

   Law 70/1996 explicitly prohibited gas flaring in production fields for the first time. MME Resolution 18/95/2009 constitutes the main regulatory framework for exploring and producing hydrocarbons, with the objective of maximizing their recovery and avoiding waste. Articles 52 and 53 prohibit gas flaring and the wasting of gas. The oil and gas sector is subject to all regulations pertaining to environmental protection and sustainability as well as consultation requirements with communities, health and safety requirements, and labor conditions. MME Resolution 40687/2022 establishes technical standards for offshore hydrocarbon exploration projects and regulates gas flaring and venting for these activities.

   MME Resolution 40687/2022 updates provisions for flaring, venting, and fugitive methane emissions. Operators, in accordance with the provisions of the competent environmental authority within the framework of an environmental license, can flare the gas recovered on the surface as a result of well control operations.
Environmental licensing processes. Unconventional reservoirs and the new terms applicable for the licensing. Decree 1076/2015257 compiles all the environmental defined Colombia’s environmental institutional framework, the rules applicable to the oil and gas sector, including those in 257  https:/ /www.funcionpublica.gov.co/eva/gestornormativo/norma.php?i=78153 (accessed August 16, 2021).


establishing requirements for leak detection, measurement and repair, technical inspections, and monitoring. For all instances relating to flaring and venting, the respective provisions in MME Resolution 40066/2022 derogate those in MME Resolution 40687/2017 and MME Resolution 18495/2009. Decre 1056/1992,258 Petroleum Code, was last amended in 2009. Further regulations have updated aspects relating to contracts, royalties, and fines, but the Petroleum Code provides key regulatory guidelines for the oil and gas industry. There are three contract types for the exploration and exploitation of oil and gas:

• PSAs, known as association contracts, with Ecopetrol
• technical evaluation contracts
• exploration and production contracts entered into with the National Hydrocarbon Agency (Agencia Nacional de Hidrocarburos [ANH]).253

Regulations are issued by the MME; the ANH defines rules for technical evaluation and exploration and production contracts. Law 23/1973254 defines the rules for pollution and environmental authorities and authorizes the enactment of the Colombian Natural Renewable Resources Code. Decree 281/1974.255 Law 99/1992256 defined Colombia’s environmental institutional framework, the National Environmental System, and introduced environmental licensing. Decree 1076/2015257 compiles all the environmental rules applicable to the oil and gas sector, including those in Decree 204/2014258 relating to regulatory requirements for unconventional reservoirs and the new terms applicable for the environmental licensing processes.

4. Legislative Jurisdictions

Gas flaring and venting are matters of national jurisdiction.

5. Associated Gas Ownership

Article 332 of the Political Constitution, 1991,259 vests the subsoil and any nonrenewable natural resources in the state. In 2003, association contracts with Ecopetrol were replaced with exploration and production contracts,260 which apply the same principles as the tax-and-royalty regime or concessions. Technical evaluation contracts allow evaluation of an area for up to 36 months, but no exploitation is allowed. If exploratory and appraisal drilling leads to production, the company is not authorized to sell it but can obtain an exploration and production contract to start exploitation. These contracts grant companies the exclusive right to explore and exploit oil and gas in a defined area. Companies have rights to all oil and gas production or the volumes remaining once royalties have been paid in kind. Companies can dispose of oil and gas production freely by negotiating with buyers in local or international markets.

Article 56 of Law 10/1986 requires all operators, privately or state-owned, to avoid wasting any gas produced. Operators should sell gas, re-inject it in the field for future use, or use it to enhance oil recovery. If the operator does not stop wasting gas within three years, the government has the right to take the ownership of gas free of charge and ensure its utilization by building the required infrastructure.

C. Regulatory Governance and Organization

6. Regulatory Authority

Ecopetrol controlled the development of hydrocarbon resources until Presidential Decree 1760/2003261 introduced two essential changes in the Colombian petroleum industry: creation of the ANH as a special entity in charge of administering and regulating hydrocarbons in Colombia (later, Decree 413/2019262 modified the legal status of the ANH and converted it into a state agency).

• transformation of Ecopetrol into a partially state-owned (Law 1198/2006263 dedicated to upstream, midstream, and downstream oil and gas activities within and outside of Colombia, governed by the applicable private law. The ANH is under the MME. It is a distinct legal status and enjoys administrative and financial autonomy. Ecopetrol became another company in the market, leaving the sole regulatory and administrative management of hydrocarbons to the ANH. ANH oversees all contractual oil and gas arrangements except for the association contracts Ecopetrol held as of December 31, 2003.

Decree 70/2000264 grants powers to the MME as the principal governing body responsible for upstream oil and gas operations. Accordingly, MME Resolution 18495/2009 updated by Resolution 40098/2015 establishes that the MME is responsible for issuing any technical rules and administrative decisions associated with the regulation and imposing applicable sanctions for noncompliance. With Resolution 18097/2012, the ANH and MME executed an interadministrative agreement that delegated certain inspection functions and regulatory activities to the ANH.

When an environmental license is required, it may be granted only at the national level by the National Environmental Licensing Authority (Autoridad Nacional de Licencias Ambientales) in accordance with Decree 1076/2015 (see footnote 257).

7. Regulatory Mandates and Responsibilities

The ANH grants flaring authorizations, sets measuring standards, and monitors compliance (see sections 9, 10, 13, and 4 of this chapter). The Ministry of Environment and Sustainable Development265 is the highest environmental authority in Colombia, responsible for the environment and renewable natural resources management. It regulates the environmental impact of Colombia’s oil and gas operations. Regional environmental agencies have the right to issue regulations, but they must align with the ministry’s national regulations and the National Environmental Licensing Authority’s licensing. The environmental license should be obtained before the initiation of a project, work, or activity.

8. Monitoring and Enforcement

Decree 1760/2003 empowers the ANH to implement the measures necessary to monitor, enforce regulations, and audit the activities related to the oil and gas industry.266 It audits Focus primarily on items such as control mechanisms, compliance with regulation, and reporting, including matters specific to flaring.

The National Environmental Licensing Authority has the power to impose sanctions on transgressors of environmental regulations and licenses. In the case of offshore activities, the maritime authority and the environmental investigations institute also play a prominent role.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 6 of MME Resolution 40066/2022 (see footnote 248) allows flaring during the exploration phase for testing purposes. Article 29 bans all venting during exploration except for safety and as part of drilling activities. Article 30 bans all venting during production. Article 34 cites safety and maintenance as the main reasons for exceptions. In all instances, the vented volumes and the underlying reasons for venting need to be reported.

10. Authorized Flaring or Venting

Any activity or operation undertaken by the operator as part of an oil and gas contract requires the relevant documentation and forms to be filed with the MME for it to approve and control the applicable activity.

Article 10 in MME Resolution 40066/2022 requires a flaring authorization during the production phase. Article 18 provides the details required for a flaring authorization. Specific
requirements for routine flaring are stipulated in article 11, and for unforeseeable events, article 19 provides for situation-specific flaring authorizations. ANH Circular 18/2014 on gas control and flaring specifies that all requests to flare should be submitted in writing to the ANH. The ANH authorizes the gas volume, time of flaring, and whether the gas flared should be subject to royalty.

11. Development Plans
Article 32 in MME Resolution 40066/2022 requires new projects to be designed to capture vented gas. Existing projects have to upgrade their facilities for capture or flaring of otherwise vented gas within the required timeframe of two years.

12. Economic Evaluation
Article 52 of MME Resolution 181495/2009 details possible flaring exceptions in cases where gas capture is not economically viable. The operator must justify that gas capture is uneconomic, and the MME must approve the justification. For routine flaring, articles 11 and 16 in MME Resolution 40066/2022 reaffirm the above approach for gas that cannot be produced economically viable.

E. Measurement and Reporting

13. Measurement and Reporting Requirements
MME Resolution 425/2016 regulates the measurement of the volume and quality of the hydrocarbons for the purposes of paying royalties. Article 17 states that the volume of gas used in a facility for artificial lift or injection, consumption in operations, power generation, and flaring should be measured. All flaring should have received prior approval from the ANH. ANH Circular 18/2014 (see footnote 267) states that operators should report the volumes of total gas produced; associated gas used for generating electricity, running compressors, or re-injection; and gas flared within the first seven days of each month. Articles 28, 29, and 30 in MME Resolution 40066/2022 (see footnote 248) require reporting of gas being vented and article 38 requires the quantification of gas captured to avoid venting.

14. Measurement Frequency and Methods
MME Resolution 425/2016 covers measurement frequency and methods. Article 7 states that the quality of gaseous hydrocarbons should be determined by establishing the density, composition, and calorific value. For the official measurement points, monthly analysis of hydrocarbons with up to 12 carbon atoms using gas chromatography should be performed. Quality tests should be carried out on representative samples taken at official sampling points using Section 4% of the latest version of the American Petroleum Institute’s Manual of Petroleum Measurement Standards. Article 17 states that all gas produced should be continuously measured. A daily log of physical and electronic data should be kept per the American Petroleum Institute Manual of Petroleum Measurement Standards.

In the late 2010s, the Comptroller General of the Republic (Contraloría General de la República), the auditor of the ANH, investigated whether the ANH was adequately enforcing natural gas production measurement and whether the information provided was transparently disclosed with easy and user-friendly access. The Comptroller General of the Republic concluded that the data and the disclosure procedures conformed to industry best practices and were managed in a timely, comprehensive, and reliable manner.

15. Engineering Estimates
Section 3 of MME Resolution 425/2016 states that methods other than direct measurements, such as engineering estimates, may be used to fulfill measurement requirements in special cases and with prior authorization from the supervisory authority. Section 29 requires a description of the volumetric and mass balance equations of liquid oil, water, and gas and field facilities highlighting the consumption, estimated losses, re-injection and gas flared, and equipment used for their determination and quantification. Descriptions should be provided separately for initial tests, extensive testing, and commercial production.

16. Record Keeping

MME Resolution 425/2016 requires operators to implement a measurement quality management system in accordance with Colombian Technical Standard NTC–ISO 10012, Measurement Systems for Petroleum, 2003. Article 28 of the resolution details the logging of daily measurements. Operators should prepare a digital or physical log of daily control activities, audits, calibrations, training, verifications related to the official measurement, and production inspection at wellheads. Subsection 6 requires operators to keep records containing the information necessary for operating the measurement management system.

17. Data Compilation and Publishing
The ANH publishes annual management reports on its website. They include data on gas flaring and the authorizations granted.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
MME Resolution 181495/2009 (see footnote 250) establishes fines specific to gas flaring and venting. According to Article 52, operators must pay royalties on flared, vented, or otherwise wasted gas unless an exception was obtained from the ANH. Article 64 imposes a fine of up to US$5,000 on any violation, in accordance with Article 67 of the Petroleum Code (see footnote 252). Article 82 in MME Resolution 40066/2022 (see footnote 248) confirms that the sanctions for infringement of its rules are those in article 21 of the Petroleum Code and article 67 of Decree 1056/1953 (see footnote 252). Article 26 of Law 5753/2015 states that the MME may impose fines of 2,000–100,000 times the legal monthly minimum wage for each breach of the obligations established in the Petroleum Code. The ANH may impose fines in case of a breach of any of the contracts it oversees, up to the value of the unfulfilled activity if the obligations have associated monetary values. If they do not, the ANH can impose a fine of up to US$50,000 for the first breach. Each subsequent breach will result in a fine up to the smaller of twice the amount initially imposed or the value of the contract’s guarantee.

The ANH may impose fines in case of a breach of any of the contracts it oversees, up to the value of the unfulfilled activity if the obligations have associated monetary values. If they do not, the ANH can impose a fine of up to US$50,000 for the first breach. Each subsequent breach will result in a fine up to the smaller of twice the amount initially imposed or the value of the contract’s guarantee.

19. Nonmonetary Penalties
Upon expiration of the terms indicated by the ANH for the payment of fines or the fulfillment of the obligations breached by the contractor, the ANH may terminate the contract if the contractor has not fulfilled its obligations. Article 11 of the Petroleum Code, 1956, states that any difference of fact or a technical nature that may arise between the interested parties and the government on the matters dealt with by the code that cannot be resolved amicably will be submitted to the opinion of three experts, one selected by the government, one by the interested party, and one by a third party. Article 68 states that the government may terminate any contract or cancel a license granted if a dispute is decided in the government’s favor.

6. Enabling Framework

20. Performance Requirements
No evidence regarding performance requirements for flaring and venting could be found in the sources consulted. Fugitive methane emissions, article 50 in MME Resolution 40066/2022 (see footnote 248) states that the required leakage elimination program needs to cover at least 95 percent of all leaking gas.

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal and emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles
In May 2017, at the One Planet Summit in Paris, Colombia joined Canada, Chile, Costa Rica, Mexico, and the US states of California.
and Washington and the Canadian provinces of Alberta, British Columbia, Nova Scotia, Ontario, and Quebec in launching the Carbon Pricing in the Americas Cooperative Framework. Law 1931/2018 established the National Program of Greenhouse Gas Emissions Tradable Quotas, a national emissions trading system (sistema de cupos y créditos), which is still awaiting implementation.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

Since its establishment under Laws 142/1994 and 143/1994, the Commission on Regulation of Energy and Gas has been the principal regulatory body responsible for regulating gas transport and commercialization. It regulates energy and gas activities to ensure the availability of efficient energy and appropriate competitive structures that prevent companies from achieving dominant positions. Gas regulations encompass aspects ranging from contractual relations and technical standards to transport conditions, sale terms, distribution, and consumption. The Unified Transportation Regulation, outlined in the Commission on Regulation of Energy and Gas Resolution 071/1999, establishes open and nondiscriminatory access to natural gas pipelines. MME Resolution 40066/2022 (see footnote 248) requires development of a program to eliminate fugitive methane emissions in upstream operations and other parts of the value chain, such as storage facilities.

## Ecuador

1.24 billion cubic meters of gas flared in 2021 (total oil production 493 thousand barrels per day)

<table>
<thead>
<tr>
<th>Change in Flare Gas Volumes*</th>
<th>Change in Flare Gas Intensity**</th>
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</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>2015-2020</td>
</tr>
<tr>
<td>17%</td>
<td>-2%</td>
</tr>
<tr>
<td>34%</td>
<td>11%</td>
</tr>
</tbody>
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*Annual volumes in billion cubic meters

**Cubic meters of gas flared per barrel of oil produced

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**Flaring volume and intensity in Ecuador, 2012–21**

### A. Policy and Targets

#### 1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Ecuador increased from 0.8 bcm in 2012 to 1.2 bcm in 2016 (figure 7). After falling to 0.9 bcm in 2018, flare gas volumes started to increase again, surpassing 1.2 bcm in 2021, when the flaring intensity reached its highest level since 2012. During this period, oil production fell slightly. There were 62 individual flare sites in the last flare count conducted in 2019.

Petroamazonas, a state-owned upstream oil company, endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2016 (World Bank, n.d.; see footnote 3). It committed to an unconditional reduction of 12 percent of its GHG emissions by 2025 from the levels in the business-as-usual scenario. In 2012, the energy sector accounted for 47 percent of GHG emissions in Ecuador. Mitigation strategies in the NDC include energy efficiency and gas utilization for power generation and LPG production. Flaring reduction is classified under energy efficiency improvement.

The National Strategy on Climate Change 2012–2025 integrates mitigation initiatives to address climate change through 2025 and coordinates climate change actions in various priority sectors, including the energy sector. The National Development Plan 2017–2021 sets as objectives for the oil and gas industry the promotion of good management practices for pollution reduction, conservation, mitigation, and adaptation to the effects of climate change.

Historically, more than half of associated gas in Ecuador has been flared. Petroamazonas has been responsible for most oil production and hence gas flaring. Its main flaring reduction initiative, the Optimization of Power Generation and Energy Efficiency Program (Optimización de la Generación Eléctrica y Eficiencia Energética en el Sistema Interconectado Petrolero) has been under way since 2008. It builds on previous efforts and aims to use associated gas for electricity generation, reduce the consumption of largely imported diesel, and produce LPG. At the end of 2020, Petroamazonas merged with Petroecuador, a national oil company that had been in charge of midstream and downstream activities. The merged company, known as Petroecuador, continues to pursue the flaring reduction initiative.

### 2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted.

### B. Legal/Regulatory Framework and Contractual Rights

#### 3. Primary and Secondary Legislation and Regulation

The main law governing the oil and gas sector is the Hydrocarbons Law, 1978, which was amended in 2010 as part of major sector reform. Article 34 stipulates that associated gas can be used by operators only for development, production, and transport operations or re-injection into deposits, with prior authorization from the Ministry of Hydrocarbons. In 2018, the Ministry of Hydrocarbons merged with two other ministries (mining and electric) to create the Ministry of Energy and Nonrenewable Natural Resources (Ministerio de Energía y Recursos Naturales no Renovables [MERNR]). Article 35 indicates that MERNR can approve the use of associated gas for industrial or commercial purposes.

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277 https://www.petroleumgonas.gob.ec/
280 https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Ecuador%20First/Primera%20NDC%20Ecuador.pdf (accessed August 17, 2021).
282 Petroamazonas was created by Executive Decree No. 315, 2010, amended by Executive Decree No. 1351A, 2012. Petroamazonas was created in 2007 and transformed into a state-owned enterprise by Executive Decree 314, 2010.
Ecuador

Article 57 of Executive Decree 1215, 2001285 states that operators must prioritize the re-injection of associated gas for enhanced oil recovery. Any gas not used for these purposes should be used, preferably for electricity generation, subject to a technical and economic assessment. The Hydrocarbons Operations Regulation, 2018286 defines MERNRR’s authority with respect to the use of associated gas in development and production operations, its transportation, flaring, and for injection or re-injection purposes.


4. Legislative Jurisdictions

Gas flaring and venting are matters of national jurisdiction. Article 34 of the Hydrocarbons Law, 1978, states that MERNRR manages, authorizes, and controls gas obtained from oil exploration and development and production at the national level.

5. Associated Gas Ownership

The state exclusively owns subsoil hydrocarbon resources in Ecuador, which it allows domestic and foreign oil and gas companies to invest in via bidding rounds. There are various upstream contract types. The most common are technical service contracts for exploration and exploitation and participation contracts (following the principles established for PSCs), in which the contractor and the state share production (or its proceeds). Contractors have rights to oil and gas according to the contract terms (Article 32 of the Hydrocarbons Law, 1978). Article 34 of the Hydrocarbons Law, 1978, vests natural gas produced in association with oil in the state. Article 36 stipulates that the Ministry of Hydrocarbons (now MERNRR) may require fields with a high gas-to-oil ratio to deliver associated gas free of charge to Petroecuador, which will pay only the expenses incurred by operators to deliver gas.

C. Regulatory Governance and Organization

6. Regulatory Authority

Until mid-2020, the Agency for the Regulation and Control of Hydrocarbons (Agencia de Regulación y Control Hidrocarburifero) regulated the exploration, exploitation, industrialization, refining, transportation, and commercialization of hydrocarbons. In 2020, it merged with the regulators overseeing the mining and electricity sectors to create the Agency for the Regulation and Control of Energy and Nonrenewable Natural Resources (Agencia de Regulación y Control de Energía y Recursos Naturales no Renovables [ARC]).289 This merger of regulatory agencies aligns with the merger of ministries to create MERNRR. The ARC assumed the responsibilities, obligations, and practices of the Agency for the Regulation and Control of Hydrocarbons.

Petroecuador is the only entity authorized to buy and sell oil, gas, and refined products. It is also responsible for most of the oil and gas production in Ecuador. The company is also tasked with negotiating and signing contracts with other companies on behalf of the government.

The Ministry of Environment oversees some special provisions under its jurisdiction, in its role of monitoring and auditing the environmental management of all industrial activity.290 The Undersecretariat of Climate Change serves as the coordinating and facilitating unit for climate finance.

7. Regulatory Mandates and Responsibilities

Article 11 of the Hydrocarbons Law, 1978 (see footnote 284) states that the Agency for the Regulation and Control of Hydrocarbons291 (now ARC) is the technical and administrative body responsible for regulating technical and operational activities in the oil and gas sector. Although independent, ARC works closely with the Vice Ministry of Hydrocarbons within MERNRR. ARC’s mission is to ensure the optimal use of hydrocarbon resources and ensure public investment and productive assets in the oil and gas sector by regulating and controlling operations and related activities.

MERNRR292 is responsible for executing, planning, and administering government energy policy. Article 50, 71, 72, and 73 of the Hydrocarbon Operations Regulation, 2018,293 which state that MERNRR’s authorization is required for the use of associated gas in development and production operations, its transportation, flaring, and for injection or re-injection into reservoirs.

The Vice Ministry of Hydrocarbons manages the assignment, administration, and modification of oil and gas acreage areas and contracts.294 The Directory of Operations and Production is responsible for planning, managing, and evaluating the oil and gas sector regulations and policies.

8. Monitoring and Enforcement

ARC has wide-ranging authority to conduct financial and technical audits of oil and gas operations and inspect exploration, production, refining, storage, transportation, and distribution facilities to ensure compliance with laws, regulations, contracts, plans, and budgets.295 Article 42 of the Environmental Rules for Hydrocarbon Activities, 2001 (see footnote 285) states that the Ministry of Environment’s Undersecretariat for Environmental Quality is responsible for monitoring and supervising operators to ensure they fulfill their obligations with respect to their environmental management plans, including emissions. Audits are carried out at least every two years to monitor the environmental aspects of operators’ activities when there is no compliance with an environmental management plan. A detects have been identified.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 39 of the Hydrocarbons Law, 1978 (see footnote 284) states that operators cannot waste, vent, or flare natural gas without authorization from MERNRR. Exceptions for flaring and venting without prior approval under special circumstances such as emergency conditions could not be identified in official documents.

10. Authorized Flaring or Venting

According to Article 72 of the Hydrocarbon Operations Regulation, 2018 (see footnote 286) flaring must be included in technical analysis and approved by MERNRR. Article 73 reiterates that flaring must be technically justified and at a minimum level. Article 57 of Executive Decree 1215, 2001 (see footnote 285) also mentions that flaring is allowed with prior approval if full use is not technically and economically feasible.

11. Development Plans

Article 50 of the Hydrocarbon Operations Regulations, 2018 (see footnote 286) requires operators to seek the approval of MERNRR before development and production activities by presenting the operations program with technical and economic justifications. The operations program should include estimated volumes of associated gas for various destinations as described in section 7 above. MERNRR’s authorization allows flaring of the volumes of associated gas so estimated in the operations program.

12. Economic Evaluation

Article 57 of Executive Decree 1215, 2001, requires operators to have an approved Environmental Management Plan establishing technically and economically feasible alternatives to gas flaring for emission reduction and control. It also requires prioritization of associated gas for re-injection and enhanced oil recovery. If re-injection is not possible, a technical and economic analysis should be carried out to identify the best use of the gas, preferably for electricity generation. If the technical and economic conditions do not allow full use in certain facilities, unused gas may be flared, with prior authorization from MERNRR.

The Ministry of Hydrocarbons (now MERNRR) assumed the responsibilities, obligations, and practices of the Ministry of Hydrocarbons within the MERNRR. The ARC has wide-ranging authority to conduct financial and technical audits of oil and gas operations and inspect exploration, production, refining, storage, transportation, and distribution facilities to ensure compliance with laws, regulations, contracts, plans, and budgets. ARC has wide-ranging authority to conduct financial and technical audits of oil and gas activities and inspect exploration, production, refining, storage, transportation, and distribution facilities to ensure compliance with laws, regulations, contracts, plans, and budgets. If re-injection is not technically and economically feasible, the operations program should include estimated volumes of associated gas for various destinations as described in section 7 above. MERNRR’s authorization allows flaring of the volumes of associated gas so estimated in the operations program.

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Ecuador

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Article 73 of the Hydrocarbon Operations Regulation, 2018 (see footnote 286) requires operators to measure the volume of gas flared and report the results to ARC. It ensures compliance with volumes from technical documents approved by MERNRR. Article 87 of the Hydrocarbon Operations Regulation, 2015, states that annual emission reports are due to ARC the first month of each subsequent year. The report should describe the use and flaring of associated natural gas.

Articles 30 and 57 of Executive Decree 1215, 2001 (see footnote 285) require operators to monitor their emissions, including from flaring. Emissions from flares must comply with maximum limits set in table 3 of annex 2 of the decree.

14. Measurement Frequency and Methods

Article 73 of the Hydrocarbon Operations Regulation, 2018, requires operators to perform chromatographic analysis of the gas flared and report the results to ARC annually. Reports should be submitted to the Ministry of the Environment with the following frequency:

- monthly for drilling operations based on daily discharge and weekly emissions analysis
- quarterly for all other operational phases, facilities, and activities based on quarterly discharges for emissions
- annually for flares located in storage facilities.

15. Engineering Estimates

Flared volumes are calculated as the difference between total fluid production and gas used onsite (for power generation and reinjection, for example). Gas flow rates are measured with sensors or estimated based on the gas-to-oil ratio and other production characteristics. Article 5 of the ministerial Agreement 091, 2007

19. Nonmonetary Penalties

Article 90 of Executive Decree 1215, 2001, provides the following nonmonetary sanctions:

- Operators may be removed from the register that allows them to provide services, thereby revoking operators’ rights.
- The Ministry of Environment may temporarily suspend the operator’s activities until there is compliance.

16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted.

17. Data Compilation and Publishing

Petroleum Gas used to issue annual management reports that included information on gas flaring reduction achieved in their Optimization of Power Generation and Energy Efficiency Program. Reports from 2016, 2017, and 2019 are available online.297 After the merger of Petroecuador and Petroamazonas, at the end of 2020, this reporting was expected to continue under Petroecuador.

18. Monetary Penalties

According to Article 77 of the Hydrocarbons Law, 1978 (see footnote 284) ARC can sanction operators for noncompliance with laws, regulations, contracts, or budgets that govern oil and gas operations. Penalties are based on an assessment of the severity of the offense, negligence, damage, economic loss to the state, and other pertinent matters.

Article 57 of Executive Decree 1215, 2001 (see footnote 285) gives operators 30 days in which to take corrective actions if flaring of associated gas is not in compliance with air quality regulations. Article 90 states that the Ministry of Environment will apply sanctions for noncompliance in accordance with Article 77 of the Hydrocarbons Law, 1978. The fines imposed by ARC or the Ministry of Environment are up to the following:

- 500 times the unified basic remuneration for the first-time violation
- 1,000–2,000 times the unified basic remuneration for the second-time violation
- 3,000–5,000 times the unified basic remuneration for the third-time violation.

In 2020, the unified basic remuneration was equal to US$400.

14. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives

No evidence regarding fiscal and emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

Flared volumes of associated gas at each site are relatively small and subject to production fluctuations. With the Optimization of Electrical Generation and Energy Efficiency Program, Petroecuador aims to reduce associated gas flaring. Gas is allocated to centralized electricity generation facilities in the Amazon region (Oriente Basin) and distributed through an interconnected system for public and private companies.
Egypt, Arab Republic of

2.08 billion cubic meters of gas flared in 2021
(total oil production 561 thousand barrels per day)

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in the Arab Republic of Egypt averaged 2.7 bcm in 2012, rose to 2.8 bcm in 2014–16, and fell to 2.1 bcm in 2021 (figure 8). The flaring intensity did not vary much during the same period. There were 103 individual flare sites in the lastflare count, conducted in 2019.

In June 2017, Egypt submitted its first NDC to the UNFCCC.298 The NDC does not commit Egypt to targets for limiting GHG emissions but lists adaptation strategies focusing on increasing the resilience of such sectors as agriculture and tourism. It also lists GHG mitigation actions, including flaring and venting reduction. In 2017, the Egyptian government endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3).

According to Egypt’s First Biennial Update Report to the UNFCCC, released in 2018, flaring and venting from oil and gas activities accounted for less than 3 percent of GHG emissions in the country.299 The report estimates that fuel combustion by industries such as power generation, transportation, and refining accounted for 85 percent of all GHG emissions. These and other activities are grouped under the energy sector, which is collectively responsible for 87 percent of total GHG emissions. To date, GHG mitigation actions have focused primarily on the energy sector. They include the reform of energy subsidies, investment in wind and solar power generation, enhancement of energy efficiency, and replacement of higher-carbon fuels with natural gas or biomass.299 Egypt has also used the CDM of the UNFCCC.

The government has been promoting the use of natural gas and enacted a new law to open the gas sector to competition. Regulated by a new regulator (see section 24 of this chapter). These reforms and government efforts to increase gas use—which would reduce GHG emissions by substituting it for fuels with higher GHG emissions intensity—may create incentives for operators to capture the associated gas they are currently flaring or venting, especially from new upstream projects.

2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted. PSCs call for avoiding the waste of petroleum resources but also for making sure that oil production is not impaired if associated gas cannot be utilized (see sections 3 and 9 of this chapter). Based on data from the Egypt General Petroleum Company (EGPC), flaring from more than two-thirds of the oil fields is less than 1 million standard cubic feet (mmscf) a day.299

The Egyptian Environmental Affairs Agency (EEAA)297 may impose emissions limits in the ElA (see section 7 of this chapter), but no specific limits on emissions from flares or vents could be found in the sources consulted.

B. Legal, Regulatory Framework, and Contractual rights

3. Primary and Secondary Legislation and Regulation

The Environmental Protection Law 4, 1994 (amended by Law 9, 2009)297 and the implementing regulations cover emissions from combustion, including flaring (see sections 6 and 7 of this chapter).

Concession agreements are granted for exploration. The three parties:

• the government as the owner of oil and gas
• a local private company or a foreign company
• one of three state-owned petroleum companies (“national companies” hereafter): EGPC, which directly or indirectly controls shares in dozens of joint ventures and privately held companies; Ganoub El Wadi Petroleum Holding, which oversees petroleum activities mainly in the southern region of Egypt; and the Egyptian Gas Holding Company (EGAS), which has been a party to all gas concession agreements since 2004.

Figure 8 Gas flaring volume and intensity in Egypt, Arab Rep., 2012–21

Note: Data are shown in this report are based on updated flaring data courtesy of the Global Gas Flaring Reduction Partnership (GGFR) using satellite data from the Colorado School of Mines.

Egypt, Arab Republic of

If there is a commercial discovery of oil and gas, a PSC is negotiated, and a joint venture is established between the contractor and one of the three national companies, the latter of which holds a 50 percent stake. The concession agreements call on operators to follow generally accepted industry methods “to prevent loss and waste of petroleum.” Other clauses of the agreements create potential conflicts (see section 7 of this chapter).

4. Legislative Jurisdictions
National laws and regulations govern the flaring and venting of associated gas.

5. Associated Gas Ownership
The government owns all oil and gas resources. The partner companies in the PSCs are given title to their shares of the produced oil and gas, including associated gas. Provided it is used in field operations (for example, for power generation or enhanced oil recovery), they can dispose of their shares of oil and gas extracted per the terms of the PSCs. Priority is given to meeting local gas market requirements, as determined by the participating national company. Other clauses in PSCs govern the pricing and sharing of associated gas under different circumstances and at different times of an asset’s life (see section 11 of this chapter).

7. Regulatory Mandates and Responsibilities

Article 40 of Law 4, the Environmental Protection Law, 1994/2009 (see footnote 303) requires emissions from combustion for all purposes to be within the limits. The limits are detailed in the annexes of Executive Regulations 338, 1995 (amended in 2005). The emissions listed do not include CO₂ or methane. Article 40 also states that the responsible parties “will be held to take all precautions necessary to minimize the pollutants in the combustion products.”

Guidelines for the EIA, published in 2001 by the EEAA, do not specifically mention flaring or venting, but they do cover gaseous emissions (Paragraph 3.6.3), which would include emissions from gas flaring, and require monitoring and environmental management plans (Paragraphs 3.9–3.11). Article 43 of Executive Regulations 338, 1995, covers oil and gas operations and calls for best international industry practices to prevent gas leaks and flares and vents. The EGPC is responsible for approving or reviewing EIA’s and environmental protection measures consistent with global best practices and ensuring proper implementation.

8. Monitoring and Enforcement
The EEAA is responsible for checking compliance with environmental regulations and enforcement of the EIA. It has the authority to conduct inspections (see section 13 of this chapter). The national companies have access to operating facilities as partners in joint ventures and act as liaisons between the partnership operating the field and the EEAA during the EIA process. In accordance with the PSC terms, the national companies approve development plans, which may include associated gas utilization options, and are responsible for ensuring compliance with development plans. Gas utilization may cover flaring and venting.

12. Economic Evaluation
No regulatory requirement to evaluate opportunities to minimize flaring and venting could be identified in available official documents. PSCs offer a structure for facilitating the sale of more associated gas to the EGPC and EGAS—and to other parties once the gas sector is reformed—for the local market.

13. Measurement and Reporting Requirements
No evidence regarding the measurement and reporting requirements could be found in the sources consulted. However, industry studies suggest that the EGPC, as the joint venture partner, has access to flaring and venting data. The EIA of oil and gas activities requires a monitoring plan, which should outline “monitoring intervals and reporting procedures” of the air emissions covered in an individual EIA. Article 17 of Executive Regulations 338, 1995 (see footnote 305) requires regulated entities to maintain records. Article 18 empowers the EEAA to conduct inspections and tests to confirm the accuracy of records. Article 43 assigns some responsibilities to the EGPC.

14. Measurement Frequency and Methods
No evidence regarding specified measurement frequency and methods could be found in the sources consulted.

15. Engineering Estimates
No evidence regarding engineering estimates could be found in the sources consulted.

16. Record Keeping
Under the EIA, operators must keep a log of emissions from combustion. No reference to flared gas volumes and composition could be found in the EIA guideline or other official documents. However, PSCs focus on marketing LPG (mostly propane and butanes), suggesting that other hydrocarbons can be flared or vented. The focus on LPG in PSCs also suggests that records on volumes are kept for fiscal purposes, at least for some natural gas liquids.


For example, table 3 in following paper is based on EGPC data: https://onepetro.org/IPTCONF/proceedings-abstract/20IPTC/3-20IPTC/D033S061R001/155988 (accessed August 13, 2021).
Egypt, Arab Republic of

17. Data Compilation and Publishing
Industry reporting suggests that the EGPC has flare volume data, but a public report detailing these data could not be found in the sources consulted.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
No evidence regarding monetary penalties could be found in the sources consulted.

19. Nonmonetary Penalties
No evidence regarding nonmonetary penalties could be found in the sources consulted. PSCs give national companies partnering in joint ventures certain rights over associated gas, which may lead them to take over the gas rights from the partners. However, it is unclear whether such a situation leads to any changes in the volumes of flared or vented gas.

G. Enabling Framework

20. Performance Requirements
No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal or emission-reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles
Egypt has implemented two CDM projects. One, registered in 2006, targeted methane venting at a landfill facility. The second project, registered in 2013, targeted flare gas recovery at a large refinery.308

23. Negotiated Agreements between the Public and the Private Sector
Development plans for upstream facilities must be agreed upon by all joint venture partners including the national companies. These negotiated plans provide the main opportunity for incorporating flaring and venting reduction from the beginning of concept development.

24. Interplay with Midstream and Downstream Regulatory Framework
The government has been promoting the use of more natural gas within the economy. It has a strategy for increasing the use of CNG vehicles. The government provides financial support for converting older gasoline or diesel vehicles into CNG, selling new CNG vehicles, and expanding the CNG filling station network.309 EGAS is expanding the distribution network to connect more residential buildings to gas supplies. The government enacted a new Gas Market Law (No. 196)310 in 2017 and established the Gas Regulatory Authority311 in 2017. The sector’s restructuring is intended to introduce competition in the gas market via third-party access to the pipeline network. This restructuring aims to give consumers or gas-trading companies the ability to procure gas supplies from producers within Egypt or via LNG imports. Previously, EGAS was the single buyer of natural gas and the de facto regulator of the gas sector.

The Cabinet sets the prices of natural gas delivered to different customer classes. As part of gas market reforms, prices were raised for all buyers except residential consumers. Industries such as cement found the reformed gas prices too high and switched to coal. In 2020, the Cabinet lowered gas prices for all industrial users.312 Given the increased availability of LNG and increased domestic gas production, lower prices may still allow cost recovery to suppliers. As one of the reasons cited for the lack of investment in flaring and venting reduction at oil and gas facilities has been that gas prices are below cost recovery, the market reforms are promising, although the Cabinet's differentiation of prices by customer class and the risk of frequent readjustments create uncertainty.

These reforms and government efforts to increase gas use may create incentives for operators to capture more of the associated gas they are currently flaring or venting. The strength of the incentive depends on the proximity of the field to processing facilities and pipeline networks, the age of the field, the gas-to-oil ratio, the share of natural gas liquids in produced volumes, and other technical and geological factors. The incentive to reduce routine flaring is probably highest for new developments, especially if the LPG content is high.

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Gabon

1.34 billion cubic meters of gas flared in 2021 (total oil production 175 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th>Year</th>
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<tr>
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Change in Flare Gas Intensity**

<table>
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<th>Year</th>
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<td>2015-2021</td>
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</tr>
<tr>
<td>2015-2020</td>
<td>16%</td>
</tr>
</tbody>
</table>

* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 9 Gas flaring volume and intensity in Gabon, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The volume of gas flared in Gabon increased from 1.3 bcm in 2012 to 1.6 bcm in 2016. Following an increase in 2019 and 2020, volumes fell to 1.3 bcm in 2021 (figure 9). The flaring intensity reached its highest level in 2020 but dropped again in 2021 while still remaining above the long-term average. Among the countries reviewed in this report, Gabon’s flaring intensity in 2021 was second only to that of the República Bolivariana de Venezuela. There were 48 individual flare sites in the last flare count, conducted in 2019.

Gabon is the fifth-largest oil producer in Sub-Saharan Africa. Current production is half its peak level, in 1997. It increased slightly in 2019 to about 220,000 barrels a day, thanks to the commissioning of new projects and investments to restore specific sites. The country has sizable associated gas resources. More than 90 percent of gas production is re-injected or flared for lack of economic alternatives.

Extreme volatility of oil prices in recent years prompted a significant reorganisation of Gabon’s oil and gas industry. Shell sold its assets to the Carlyle Fund at the end of 2017. In July 2020, Perenco bought a large part of the assets of Total Gabon and became the leading national producer (producing 416 million m³ of gas in 2019), supplying thermal power plants in Port-Gentil and Libreville with approximately 200 megawatts (MW) of gas-fired power generation capacity. Despite the efforts made since 2009 to diversify the economy, the oil sector remains leading contributor to the national budget. According to the International Monetary Fund, the share of oil in Gabon’s gross domestic product (GDP) was 38.5 percent in 2019.

In 2016, Gabon endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). It also mentions the potential for new opportunities offered by the green economy (Green Gabon).

A National Climate Plan was developed to introduce climate concerns in the country’s development program, and the Climate Council (Conseil National Climat) has been given a prominent position in the government. The objectives are to combat climate change and its effects, prevent deforestation, halt land degradation, and stop biodiversity erosion. At the same time, it mentions the potential for new opportunities offered by the green economy (Green Gabon).

2. Targets and Limits

At the United Nations Climate Summit in Durban in December 2011, President Ali Bongo Ondimba announced the objective set for Gabon’s oil industry of reducing the volume of gas flared by 2015 by a minimum of 60 percent (compared with 2009 levels). This target was not captured in legislation, but a national gas flaring reduction strategy was prepared. The plan required all oil companies operating in Gabon to submit individual plans detailing how they would reduce gas flaring at their facilities.

3. Environmental Objectives

The government expects that measures adopted to reduce routine flaring will reduce GHG emissions by 17.3 million tonnes of CO₂ in 2025 compared with the business-as-usual scenario defined in its NDC. Gabon has unconditionally committed to reducing emissions by at least 50 percent by 2025 compared with the business-as-usual scenario defined in its NDC.

313 Maximizing oil production in Gabon generally requires a careful balancing of reservoir pressure related to oil and gas drives, often involving the re-injection of gas into the gas cap, and at times water into the underlying water reservoir. Also, as many of the oil reservoirs have relatively low natural pressure, gas lift is a widespread technology.

314 The UNFCCC has acknowledged that carbon dioxide (CO₂) is a greenhouse gas (GHG) that causes climate change, and the 1997 Kyoto Protocol set a target for developed countries to reduce their greenhouse gas emissions by 5.2 percent (relative to 1990 levels) by 2012. The Kyoto Protocol entered into force in 2005.

315 The Paris Agreement entered into force in 2016, replacing the Kyoto Protocol. The Agreement set the target of limiting global warming to well below 2 degrees Celsius above pre-industrial levels, with efforts to limit the increase to 1.5 degrees Celsius.

316 Gabon’s development strategy, which emphasizes resource diversification and economic development, is guided by the Green Gabon strategy (2010–2030). The strategy’s goals are to promote sustainable natural resource management, protect the environment, and ensure the equitable and sustainable use of natural resources.

317 Gabon’s legislation includes provisions designed to end routine gas flaring and develop its associated and nonassociated gas reserves with a view to transporting and selling natural gas to large industrial users in the country. Article 118 of the new petroleum law, Law No. 002/2019, sets out a 10-year gas plan, the objectives and conditions of which will be defined by regulation.

318 The provisions made in the model PSC align with the key aspects of the new petroleum code, although field-specific arrangements can vary.

Reference:
- World Bank (2020). Gabon Emergent Strategic Plan. [Online]. Available at: https://www.ctc-n.org/content/indc-gabon

Note: Data shown in this report are based on gas flaring data collected by the Gabon Gas Flaring Reduction Partnership (G2F) using satellite data from the Carbon Brief of Images.
Gabon

B. Legal, Regulatory Framework, and Contractual rights

3. Primary and Secondary Legislation and Regulation

Before August 2014, the oil industry in Gabon was governed by Law No. 15/1962, as amended by Law No. 14/74, 1975,217 and Law No. 14/82, 1983. None of these laws contained provisions to limit flaring and venting. Such provisions were first introduced in legislation in November 2009, through a decree forbidding continuous flaring of associated gas (Arrêté N° 00266/MMPH/SIG/ DGA) and in 2010, through a decree imposing penalties on flaring to be gradually applied from January 2011 to December 2014 (Arrêté N° 00027/MMPH/SIG/DAEJF). These decrees have never been enforced.

PSCs govern most hydrocarbon activities.318 The latest model version bans flaring and venting while allowing several exceptions. PSCs can include specific clauses departing from general regulations.

On August 28, 2014, the government enacted Law No. 01/2014/AN218 to encourage exploration and development and reduce gas flaring by promoting gas monetization options. Law No. 01/2014/AN218 offered incentives to encourage exploration and development and reduce gas flaring. On August 28, 2014, the government enacted Law No. 01/2014/AN218 to encourage exploration and development and reduce gas flaring by promoting gas monetization options. Law No. 01/2014/AN218 offered incentives to encourage exploration and development and reduce gas flaring by promoting gas monetization options.

Law No. 01/2014/AN218 requires prior approval of an EIA by the Ministry of Environment for offshore oil and gas operations.

4. Legislative Jurisdictions

Gas flaring and venting are matters of national jurisdiction.

5. Associated Gas Ownership

Article 10 of Law No. 002/2019 provides that all hydrocarbon resources, essential infrastructure, studies, data, and information acquired or produced during oil operations are the exclusive property of the state. Article 124 further provides that the associated gas from an onshore deposit is not allocated to self-consumption in oil operations and the nonassociated gas declared not commercially exploitable remain the property of the state.

In line with the requirements established for PSCs as the primary licencing agreement, Article 117 requires natural gas producers to deliver to the state or to a third party designated by it, on a priority basis, a share of their annual production to satisfy the domestic market’s needs. The methods for determining the share of natural gas are set by regulation and hydrocarbon contracts. The official sale price is set by regulation.

C. Regulatory Governance and Organization

6. Regulatory Authority

Following the introduction of the new legislation, investor interest increased, and Gabon has signed nine new oil production contracts. As of the time of writing, no decrees had been put in place to issue regulations for Law No. 002/2019.

Article 61 of Gabon’s Environmental Law, Law No. 007/2014, requires prior approval of an EIA by the Ministry of Environment for offshore oil and gas operations.

Article 17 states that the ministry in charge of hydrocarbons (MPGHH) is the competent authority ensuring implementation of the government’s policy on the upstream and downstream oil and gas industry.

Article 18 states that the application of the regulations governing the upstream, midstream, and downstream oil and gas sectors is to be carried out by the ministry department in charge of hydrocarbons, currently the General Directorate of Hydrocarbons (Direction Générale des Hydrocarbures [DGH]).

Article 28 defines the responsibilities of an independent administrative authority in the oil and gas sector (responsibilities currently with DGH), which include the following:

− guaranteeing free competition in the oil and gas sector, per the Central African Economic and Monetary Community [Communauté Économique et Monétaire de l’Afrique Centrale] Code on anti-corruption;
− contributing to the development of technical specifications in the oil and gas sector and ensuring operators’ compliance with technical, quality, hygiene, health, and environmental specifications, as defined in the legislation;
− guaranteeing pricing transparency and nondiscriminatory third-party access to essential infrastructure.

Article 27 reiterates the right of the National Hydrocarbons Company (Société Nationale des Hydrocarbures) to participate in exploiting, marketing, and distributing hydrocarbons and their associated products. Founded in 2011, the National Hydrocarbons Company—also known as the Gabon Oil Company322—reports to the President’s Office and is under the technical supervision of the MPGHH and the financial supervision of the Ministry of Economy. The new law no longer expressly refers to this company as the national operator. The Gabon Oil Company is defined only as an operator whose capital is held exclusively by the state. Its functions include the following:

− holding the government’s interests in national hydrocarbon resources and shares in private companies;
− investing on behalf of the state (alone or in joint ventures with private companies) in upstream or downstream oil and gas projects;
− undertaking any activity in the oil and gas supply chain, with the same rights and obligations as any other operator;
− entering into agreements with the state, in the same way as private companies, to operate new gas-processing facilities and pipeline infrastructure, potentially in a joint venture with private operators.

7. Regulatory Mandates and Responsibilities

The DGH was created by Decree No. 346/PRES, 1977. It is responsible for the implementation of Gabon’s oil policy and the management and development of its hydrocarbon resources. Article 242 of Law No. 002/2019 states that the DGH’s control relates to compliance with the specifications and technical characteristics of hydrocarbons, petroleum products, gas, and derivatives sold in the domestic market and the quality of water, sludge, and used oils from hydrocarbon activities. The DGH’s activities encompass technical, accounting, legal, and fiscal administration (Article 243).

The Ministry of Environment320 is mandated to authorize gas flaring and venting under extraordinary circumstances and approve (jointly with the MPGHH) gas flaring reduction plans for production fields.

8. Monitoring and Enforcement

Article 246 of Law No. 002/2019 states that the measurement of oil and gas production is the exclusive prerogative of the state but that its responsibilities and functions can be delegated. An important responsibility of the regulator is to regularly check the compliance of all measurement devices and equipment in the presence of the operator. According to Article 251, the MPGHH is to carry out technical audits on integrity, guaranteeing the regular and optimal functioning of all measuring, metering, and other installations for oil and gas production. The MPGHH is to collect data from operators and monitor gas flaring. Because of the scarcity of resources at the DGH and the absence of well-defined reporting guidelines, the quality and quantity of data collected are generally poor and do not provide a sound basis for enforcing regulations.

Gabon

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 125 of Law No. 002/2019 (see footnote 315) prohibits the flaring and venting of gas in Gabon. No evidence of situations exempt from this general prohibition without government approval could be found in the sources consulted. However, at the request of the contractor, the environmental authority can authorize flaring and venting for a period.

10. Authorized Flaring or Venting

According to Article 125 of Law No. 002/2019, at the request of the contractor and on the advice of the MPGHM, flaring and venting may be authorized within a period determined by the Ministry of Environment. Upon notification, the applicable thresholds (subject to periodical revision) will be determined for each field.

11. Development Plans

Article 126 of Law No. 002/2019 requires operators to submit a gas flaring reduction plan for all their production fields for the joint approval of the MPGHM and the Ministry of Environment.

12. Economic Evaluation

No evidence regarding economic evaluations could be found in the sources consulted.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Article 127 of Law No. 002/2019 (see footnote 315) requires operators to equip production facilities with flare measuring devices. Article 248 requires that the ministry responsible for hydrocarbons approve the choice, location, installation, modification, and addition of any equipment for measuring and metering oil and gas production. Article 127 requires operators to report the volumes of gas flared to the ministry responsible for hydrocarbons. Failure to declare any volume of gas flared subjects the operator to a fine, the amount of which will be set by regulation in the future. Article 119 states that contractors are required to transmit to the DGH all information relating to the gas balance in accordance with the procedures to be set by future regulation. Article 182 mandates that all hydrocarbon permit holders provide the DGH with a report on its activities and any administrative, technical, economic, and financial information related to its operational responsibility, quality, health, and the environment under the conditions and time required by the regulations. The model PSC states that any flared volumes must be reported to the DGH monthly.

14. Measurement Frequency and Methods

Article 251 of Law No. 002/2019 states that the units, methods, and standard conditions for measuring the volumes of oil and gas and the marketing of natural gas or products derived from oil and gas are set by regulation. No regulations have yet been approved. There is also no stated requirement for the fiscal metering of flare gas.

15. Engineering Estimates

Law No. 002/2019 states that gas stream volumes can be estimated based on gas-to-oil ratios or measured by ultrasonic or other gas flow meters.

16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted.

17. Data Compilation and Publishing

The DGH is in charge of collecting, processing, and disseminating flaring data within the government (notably the Climate Council).

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

Law No. 002/2019 (see footnote 315) sets a series of sanctions, including penalties for contractors that fail to submit required studies and reports for their upstream activities, gas-flaring violations, and noncompliance with regard to flaring-reduction plans or flaring thresholds. Article 265 doubles the penalties in the event of a repeated offense. Article 266 provides that future regulations will determine the methods for the payment of penalties.

Article 269 of section 2 imposes a penalty of CFAF 50 million–CFAF 2.5 billion (about US$89,000–US$4.5 million as of September 2021) on any contractor that violates any of the provisions relating to measuring or metering oil and gas, including system calibration. The same penalty applies if the contractor does not execute the flaring reduction plan or comply with the flaring thresholds set by the regulation. Article 278 imposes a penalty of CFAF 10–CFAF 100 million (about US$18,000–US$180,000 as of September 2021) on any contractor that violates the provisions relating to metering or oil and gas production. Article 280 imposes a penalty of CFAF 1–CFAF 2.5 billion (about US$1.8 million–US$4.5 million as of September 2021) on any contractor that fails to submit the flaring reduction plan or comply with the flaring thresholds set by the regulation. Article 282 imposes a penalty of CFAF 10–CFAF 100 million (about US$18,000–US$180,000 as of September 2021) on any contractor that violates the provisions relating to measuring or metering oil and gas, including system calibration.

19. Nonmonetary Penalties

Article 263 of Law No. 002/2019 states that the applicable future legislation and hydrocarbon contracts will provide administrative sanctions. Article 265 provides for the withdrawal of authorizations and bans on oil and gas production for repeated offenses. This provision is not new: In January 2013, Gabon revoked the Obangué license of Addax Petroleum after the company allegedly failed to pay its customs duties and comply with other laws.

G. Enabling Framework

20. Performance Requirements

Article 128 of Law No. 002/2019 (see footnote 315) requires oil and gas producers to develop or use suitable techniques for the recovery and re-injection of gas to optimize production and conserve the resource. Article 129 states that future regulations will define methods for controlling the volumes of gas flared and discharged and set forth plans to reduce flaring.

21. Fiscal and Emission Reduction Incentives

In the model PSCs (see footnote 318), contract terms for oil are clearly defined, but terms for possible gas discovery or associated gas volumes remain vague (subject to a separate agreement). Article 215 of Law No. 002/2019 reduces the government’s minimum share of profit oil in PSCs to 45 percent for the conventional zone and 40 percent in offshore oil exploitation (against 55 percent and 50 percent, respectively, in the 2014 law). The government’s share of profit gas is 25 percent for the conventional zone and 20 percent for deep offshore zones.

Law No. 002/2019 offers the possibility of removing the corporate tax of 35 percent on the contractor’s share of profit oil in the old law and lowers the proportional mining royalty, which is now 7–15 percent for liquid hydrocarbons produced onshore and 5–12 percent for offshore. For natural gas, these rates are 5–10 percent onshore and 2–8 percent offshore. The new legislation also improves cost-recovery terms for operators. The cost-recovery limits for liquids are 70 percent for onshore and 75 percent for offshore; the limits for gas are 80 percent for onshore and 90 percent for offshore.

22. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector

In 2011, Gabon committed to reducing the volume of gas flared by 20% by a minimum of 60 percent compared with 2009 levels. A national gas flaring reduction plan required oil companies operating in Gabon to submit plans to reduce gas flaring on their operating assets. Accordingly, oil companies implemented several flare-reduction projects from 2011 to 2015. These projects resulted in a moderate reduction of about 10 percent of the volumes flared.

24. Interplay with Midstream and Downstream Regulatory Framework

Article 8 of Law No. 002/2019 states that any license holder of an administrative authorization to carry out hydrocarbon activities has access to essential infrastructure, subject to availability and the priority of access granted to certain holders by the DGH. This third-party access is exercised in line with the principles of tariff transparency, equal treatment, and nondiscrimination.
### Indonesia

1.67 billion cubic meters of gas flared in 2021  
(total oil production 658 thousand barrels per day)

<table>
<thead>
<tr>
<th>Change in Flare Gas Volumes*</th>
<th>2015-2021</th>
<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>-43%</strong></td>
<td><strong>-35%</strong></td>
<td></td>
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</table>

<table>
<thead>
<tr>
<th>Change in Flare Gas Intensity**</th>
<th>2015-2021</th>
<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>-32%</strong></td>
<td><strong>-28%</strong></td>
<td></td>
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</tbody>
</table>

* Annual volumes in billion cubic meters

** Cubic meters of gas flared per barrel of oil produced

** Figure 10 Gas flaring volume and intensity in Indonesia, 2012–21

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### A. Policy and Targets

1. **Background and the Role of Reductions in Meeting Environmental and Economic Objectives**

The volume of gas flared in Indonesia decreased from 3.5 bcm in 2012 to 1.7 bcm in 2021 (figure 10). The rate of decline was much greater than for oil production, which fell by more than 20 percent during the period. The flaring intensity correspondingly followed a generally declining trend, falling by more than oil production. There were 152 individual flare sites in the last flare count, conducted in 2019.

Indonesia endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2017 (World Bank, n.d.; see footnote 3). It also participates in the Global Methane Initiative (n.d.; see footnote 29). In 2021, Indonesia submitted an updated NDC to the UNFCCC that committed it to an unconditional reduction of 29 percent and a conditional reduction of 41 percent in GHG emissions by 2030 relative to its business-as-usual scenario. The NDC does not mention flaring or venting.

In 2010, the government launched the Indonesia Climate Change Sectoral Roadmap, an initiative to incorporate the climate change agenda in the country’s development plan. In 2012, the Ministry of Energy and Mineral Resources (Kementerian Energi dan Sumber Daya Mineral [ESDM]) issued specific flaring regulations to optimize resource utilization and reduce flaring and GHG emissions. Building upon these efforts, the government in 2017 issued the National Energy Strategy, an initiative to transition to a cleaner, more climate-smart energy sector.

### B. Legal/Regulatory Framework and Contractual Rights

3. **Primary and Secondary Legislation and Regulation**

Articles 2 and 3 of the 2001 Oil and Gas Law, Law 22/2001, cover the environmental considerations relevant to the country’s oil and gas industry.

Ministerial regulation ESDM 21/2021 regulates gas flaring. It assigns overall flaring responsibility to the ESDM and its directorate, the Directorate General of Oil and Gas (DG Migas). ESDM 3/2012 covers the conditions under which flaring is permitted, procedures to follow in all instances of gas flaring, and metering and reporting requirements (see sections 9 and 10 of this chapter).

The primary objective of ESDM 23/2021 is to optimize resource use, by increasing the use of otherwise flared gas (Article 2). In Article 1, the country’s Special Task Force for Upstream Oil and Gas Business Activities (Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi [SKH Migas]) is given responsibility for the business aspects. In this context, SKH Migas is tasked with marketing gas that might otherwise be flared and setting the price of this gas.

Government Regulation 25/2004, issued by the president of Indonesia, regulates business activities related to the upstream oil and gas sector without any specific mention of flaring or venting. Although not directly aimed at flaring and venting of associated gas, several regulations lay the foundations for the pricing of gas sold to other sectors:

- Government Regulation 26/2004 regulates gas use in the downstream sector, defined as processing, transport, and storage of gas.

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Indonesia

- Ministerial regulations ESDM 5/2017, 334 and ESDM 14/2019, 335 establish the pricing mechanisms for gas transported by pipeline sold on the domestic market.
- Ministerial regulation ESDM 45/2017, 336 covers the use of gas for electricity generation, such as volume allocation for national purposes (Article 3) or price setting, for which Article 8 of the amendment ESDM 10/2020, 337 provides numerical updates.

4. Legislative Jurisdictions
Gas flaring is a matter of national jurisdiction.

5. Associated Gas Ownership
Article 6 of Law 22/2001 and Article 24 of Government Regulation 35/2004 state that ownership of gas remains entirely with the government until the point of delivery, when the contractor assumes ownership of cost oil and gas and the contractual share of profit oil and gas. Ownership of gas not sold, including associated gas, remains with the government. Gas-related business activities, including the transfer of ownership, are covered in the cooperation contracts, a type of agreement specific to Indonesia that closely follows the industry practice established for PSCs. In line with the above, Articles 4–8 of ESDM 32/2017 authorize SKK Migas to conduct the sales process through a bidding mechanism for gas that would otherwise have been flared.

C. Regulatory Governance and Organization

6. Regulatory Authority
Articles 1 and 9 of ESDM 31/2012 (see footnote 328) assign overall responsibility and approval powers for flaring permission and reporting activities to the ESDM and DG Migas. Article 1 of ESDM 32/2017 (see footnote 329) appoints SKK Migas as the country’s special task force for managing upstream oil and gas activities covered by cooperation contracts, making it responsible for the utilisation of gas that would otherwise have been flared. Although not an institution within the ESDM, SKH Migas is under the guidance and supervision of the ESDM.

7. Regulatory Mandates and Responsibilities
Flaring-related responsibilities are divided between the ESDM (including DG Migas) and SKH Migas. According to ESDM 31/2012, the ESDM sets the policy direction and DG Migas formulates and implements policies and technical standards (Article 1). Regarding the use of gas that might otherwise have been flared, Article 1 of ESDM 32/2017 appoints SKH Migas as the agency responsible for managing the bidding process for the associated gas currently being flared under the guidance and supervision of the ESDM (see section 22 of this chapter). According to ESDM 45/2017 (see footnote 334), in combination with the amendment in Article 8 of ESDM 10/2020 (see footnote 335), the ESDM is also responsible for overseeing natural gas used in electricity generation.

8. Monitoring and Enforcement
If flaring limits are exceeded, the contractor or license holder is required to conduct a gas optimization study for submission to DG Migas, which can then either approve or reject its findings (Articles 3–5 of ESDM 31/2012). SKH Migas is entitled to revoke the utilization license for gas previously or otherwise flared if the promised implementation commitment is not met in time (Article 10 of ESDM 32/2017).

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval
Article 6 of ESDM 31/2012 (see footnote 328) allows flaring without the prior submission of a gas optimization study if it is done for safety reasons, because of an emergency, or as part of well testing. However, the ESDM’s inspection service needs to be notified within 24 hours of the incident, and a written report must be submitted to DG Migas for subsequent verification purposes.

10. Authorized Flaring or Venting
Article 3 of ESDM 31/2012 sets the following volume limitations on gas flared authorized by DG Migas:
- 3 percent of the field’s gas production
- 5 mmscf a day (six-month field average) in a field
- 0.3 percent of gas-processing facility intake
- 0.8 percent of refinery intake

If the above limits are exceeded, Articles 4 and 5 of ESDM 31/2012 require contractors or license holders to conduct a gas optimization study and submit it to DG Migas for evaluation, based on which DG Migas can approve operational flaring. DG Migas is required to provide reasons for rejecting the submission.

11. Development Plans
Unless flaring is permitted, associated gas is usually not covered by cooperation contracts and, therefore, not part of field development plans. However, each cooperation contract must contain environmental management provisions (Article 11 of Law 22/2001 (see footnote 327) and Article 39 of Government Regulation 35/2004 (see footnote 330)), although they are not required to include flaring and venting according to the existing legislation.

12. Economic Evaluation
Article 4 of ESDM 31/2012 requires contractors or license holders to conduct a comprehensive gas optimization study when exceeding the permissible flare gas volumes. Article 5 requires DG Migas to evaluate this study before approving or rejecting flaring permits. Article 7 of ESDM 32/2017 (see footnote 329) requires bidders for associated gas currently being flared to provide technical, commercial, and financial parameters when competing for gas volumes. SKH Migas evaluates the bid proposals and makes recommendations on bid selection to the ESDM.

E. Measurement and Reporting

13. Measurement and Reporting Requirements
Article 7 of ESDM 31/2012 (see footnote 328) sets metering requirements for flared gas. Specifically, it requires meters to be used if flaring more than 3 mmscf a day per facility, and in all cases if sour gas is being flared. If flaring less than 3 mmscf a day or if the meter on site cannot read measurements, the operator can calculate the volume of gas flared instead of metering it. Article 8 requires the submission of regular gas flaring reports.

14. Measurement Frequency and Methods
According to Article 8 of ESDM 31/2012, contractors or license holders are required to submit regular flaring reports to DG Migas every six months. These reports must cover items such as flare gas volumes and countermeasures.

15. Engineering Estimates
Article 7 of ESDM 31/2012 permits calculated flared gas volumes for gas other than sour gas below the threshold of 3 mmscf a day per facility or if the installed meter is not working properly. In the event of an irregularity or a failure to report, DG Migas requires that a meter be installed.

16. Record Keeping
There is no obligation to maintain logs outside of the standard reporting requirements.

17. Data Compilation and Publishing
DG Migas receives gas flaring reports regularly and is known to be willing to share them upon request on a case-by-case basis. DG Migas does not formally or regularly publish flaring-related statistics.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
No evidence regarding monetary penalties could be found in the sources consulted.

19. Nonmonetary Penalties
Articles 4 and 5 of ESDM 31/2012 (see footnote 328) require contractors or license holders that exceed the limits allowed for flaring in Article 3 to conduct a gas optimization study for submission to DG Migas, which can then approve or reject the findings. Article 10 of ESDM 32/2017 (see footnote 329) allows SKK Migas to revoke the flare gas allocation from the selected bidder if they fail to commence work within three months following the award or fail to start production within 12 months. However, there are no known cases of revocation.
Indonesia

G. Enabling Framework

20. Performance Requirements
The only performance standards identified relate to the requirement to start production and flare gas utilization within 12 months of the award date in the bid rounds conducted by SKK Migas for gas being flared. There is no mention of an emission standard to be achieved.

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal and emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles
Article 7 of ESDM 32/2017 (see footnote 329) appoints SKK Migas to sell gas currently being flared through a bidding process. The bid parameters include the price the bidder is willing to pay, investment commitment, and the production period. Based on an evaluation of the bid parameters, SKK Migas recommends to the EDSM, which selects the bid winner. The gas price offered by bidders has a ceiling of US$0.35/MMBtu for bidders that are public entities and US$3.67/MMBtu for private entities. All prices are subject to correction factors based on the content of the contaminants. Given the significant difference in bid price ceilings, the other project parameters would need to be very attractive to attract private sector interest.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
Several regulations relate to the transport and pricing of gas that is sold to other sectors further downstream (see section 3 of this chapter). Downstream activities are supervised by a separate regulatory agency, BPH Migas. Article 31 of Government Regulation 36/2004 (see footnote 331) requires midstream and downstream license holders to make surplus facility capacity available to third parties, which would help integrate flare gas commercialization projects.
Kazakhstan

1.51 billion cubic meters of gas flared in 2021 (total oil production 1,764 thousand barrels per day)

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Kazakhstan has achieved a remarkable reduction in both the volume of gas flared and the flaring intensity in recent years. Between 2012 and 2021, both metrics fell by about two-thirds. The volume flared fell from 4 bcm in 2012 to 1.5 bcm in 2021, and the flaring intensity fell at an even faster rate from 7.2 m³ to 2.3 m³ per barrel of crude oil produced (figure 11). Oil production increased by 16 percent during this period. There were 77 individual flare sites in the last flare count, conducted in 2019.

In 2016, the government and the national oil company, KazMunayGas, endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). Kazakhstan also participates in the Global Methane Initiative (n.d.; see footnote 29). In December 2016, Kazakhstan submitted its first NDC to the UNFCCC. It set an unconditional target of a 15 percent reduction in GHG emissions from the 1990 level by the end of 2030. The NDC also includes a reduction target of 25 percent as a conditional contribution.

Kazakhstan has prohibited flaring associated gas since the mid-2000s, with certain exceptions. The Law on Subsoil and Subsoil Use, 2017, prohibits the flaring of raw gas. 343 Kazakhstan established the first gas utilization project to eliminate routine flaring. The project’s success was recognized with an Excellence in Flaring Reduction Award at the 2012 GGFR forum.

2. Targets and Limits

No evidence regarding overarching targets and limits could be found in the sources consulted. However, Article 146 of the Law on Subsoil and Subsoil Use, 2017, prohibits the flaring of raw gas. 342 According to Article 147, operators must "carry out activities aimed at minimizing the volume of raw gas flaring." The Ministry of Energy calculates permissible volumes of gas that can be flared (see section 7 of this chapter). Field development plans must include a section detailing how raw gas will be processed and utilized.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation

Previously, flaring emissions were regulated under the Environmental Code, 2007, which was superseded in July 2021 by the Environmental Code, 2021. 340 Kazakhstan established the first GHG emissions trading system (ETS) in Asia in 2013. Updates to the Environmental Code guided different phases of the ETS market. There is no explicit mention of venting in either the subsoil or environmental laws, but the GHG ETS began covering methane emissions in 2021.

KazMunayGas is a partner in the largest upstream projects—including Tengiz, Kashagan, and Karachaganak. Flaring from these projects has been reduced, in some cases significantly. For example, the operator of the Tengiz field, Tengizchevroil, 341 reduced flaring emissions by more than 94 percent within a decade via several capital projects, including an investment in a four-year gas utilisation project to eliminate routine flaring. The project’s success was recognised with an Excellence in Flaring Reduction Award at the 2012 GGFR forums.

Kazakhstan

without associated gas utilization plans. The Law on Subsoil and Subsoil Use, 2017, prohibits the flaring of associated gas, with certain exceptions. The law superseded the 2010 version. It includes the same flaring restrictions but adds some clarifications.

The Environmental Code, 2021 (see footnote 340) requires entities responsible for gaseous emissions to obtain a permit and introduces the concept of an integrated environmental permit (see section 13 of this chapter). In 2011, GHG regulations were added to the Environmental Code. Relevant articles have been updated as necessary to set the new quotas for phases of the national ETS regime.

4. Legislative Jurisdictions

The flaring of associated gas and the emissions associated with flaring are regulated primarily at the national level, but local authorities have jurisdiction over environmental regulation (Article 28 of the Environment Code, 2021). According to the Environmental Code, 2021, local executive bodies, in agreement with the national environmental regulator, have the power to “establish stricter environmental standards” for air emissions if local conditions warrant them (Article 200). Local executive bodies and the regional subdivision of the national environmental regulator can introduce temporary measures during unfavorable meteorological conditions or increased urban air pollution, including shutting down factories (Article 210). These and other powers granted to local executive bodies cover stationary and mobile sources of air emissions, including the combustion of raw gas in flares (Article 202). Taxes on emissions and penalties for violations are paid mostly to local governments.

5. Associated Gas Ownership

Kazakhstan uses concessions to grant companies the right to explore and exploit hydrocarbons, except for legacy PSCs (signed under the 2010 version of the subsoil law). It reiterates the principle of the state’s ownership of associated gas. Article 15 of the Law on Gas and Gas Supply, 2012, gives the state the right to purchase gas that is not authorized for self-use.

C. Regulatory Governance and Organization

6. Regulatory Authority

The Ministry of Energy is the “authorized body” (regulator) of hydrocarbons. The Ministry’s Department of State Control in the Sphere of Hydrocarbons and Subsoil Use (DSCHS) regulates flaring. The Ministry of Ecology, Geology, and Natural Resources (MEGNR) is the environmental regulator and has jurisdiction over flaring emissions. Territorial divisions of MEGNR and local executive bodies play roles in implementing environmental regulations.

7. Regulatory Mandates and Responsibilities

According to regulations defining its objectives and functions, the DSCHS, on behalf of the Ministry of Energy, is responsible for developing rules for issuing flaring permits and ensuring their approval and registration. The Ministry of Energy is responsible for, and the DSCHS participates in, estimating permissible volumes of raw gas flaring, measurement, and calculation standards, as stipulated in Article 146 of the Law on Subsoil and Subsoil Use, 2017 (see footnote 337). These standards are reflected in field development plans and EIAs. The standards can be revised in response to technological developments or individual needs of fields. MEGNR is responsible for conducting EIAs or approving the EIAs conducted by licensed companies and issuing environmental permits, including those for emissions from flares. Emissions from flares should be within the flare volumes allowed in flare permits. If they are not, environmental regulations prevail and penalties levied accordingly.

8. Monitoring and Enforcement

The DSCHS is responsible for monitoring and enforcing compliance with the oil and gas industry permits it issues. It can conduct scheduled or unscheduled inspections, enlist specialists from state bodies and other organizations as well as foreign and local experts, and request any document and data deemed necessary for ensuring compliance. The DSCHS coordinates with two interregional departments of the Ministry of Energy: the Western Interregional Department of State Inspection in the Oil and Gas Complex and the Southern Interregional Department of State Inspection in the Oil and Gas Complex.

MEGNR has the authority to inspect facilities for compliance with environmental permits. If a facility exceeds its permissible emissions levels from flares, MEGNR has the authority to penalize violations of environmental permits.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

According to Article 146 of the Law on Subsoil and Subsoil Use, 2017 (see footnote 337), a permit is not required for flaring under emergency conditions. The operator must report the reasons for and volumes of flaring to the Ministry of Energy and MEGNR within 10 days. An emergency is defined as a threat to personnel life, public health, or the environment.

10. Authorized Flaring or Venting

According to Article 146 of the Law on Subsoil and Subsoil Use, 2017, flaring is allowed during emergencies, well testing, trial operation of the field, and if it is unavoidable on technical grounds. Except in an emergency, flaring under all other circumstances requires a permit from the Ministry of Energy. Applications for a permit to flare raw gas can be submitted online.

There are special considerations for the northern Caspian Sea region. For example, according to Article 274 of the Environmental Code, 2021 (see footnote 340), flaring of liquids during well operations is prohibited and “flaring of hydrocarbons during well testing should be minimized using the best available technology, which is the safest for the environment.” The best available technology is identified during the EIA. Such flaring is allowed “only under favorable weather conditions conducive to the dispersion of the smoke plume, while the design of the flare units must ensure the complete combustion of hydrocarbons.”

11. Development Plans

Article 147 of the Law on Subsoil and Subsoil Use, 2017, requires operators to minimize the volume of raw gas flaring and field development plans to include a section on raw gas processing or utilization. Field development plans are reviewed by the Central Commission for Exploration and Development. With the involvement of independent experts with special knowledge in the field of geology and development and not interested in the results of the examination, as stipulated in Article 140. Articles 134–143 detail the necessary project documents and the review process. The Ministry of Energy’s Department of Subsoil Use organizes an independent review of project documents and development plans. According to Article 147, the gas-processing program is to be updated every three years. Annual reports on the implementation of the program must be submitted to the Ministry of Energy.

12. Economic Evaluation

Article 147 of the Law on Subsoil and Subsoil Use, 2017, prohibits the extraction of hydrocarbons without processing all raw gas. However, the law provides for several exceptions, all of which must be outlined in the field development plan. Article 146 provides exceptions under which flaring is permitted. Article 147 adds several others. The field development plan may include the operator’s own use of the gas or its sale to other parties. If these options cannot be justified economically, the field development plan may include re-injection for storage or enhanced oil recovery as long as other methods are ineffective in maintaining reservoir pressure and re-injection does not harm the environment.

There are also regional considerations. For example, Article 274 of the Environmental Code, 2021 (see footnote 340) prohibits the injection of associated gas for enhanced oil recovery in excess of the design parameters and volumes approved in the field development plan in the northern Caspian Sea region. These plans must be reviewed by an expert panel organized by the Department
Kazakhstan

of Subsoil Use of the Ministry of Energy before being considered by the latter for approval.

13. Measurement and Reporting Requirements

Flaring during oil and gas operations must be measured and reported to the Ministry of Energy. Article 76 of the Law on Subsoil and Subsoil Use, 2017 (see footnote 337) requires licensees to report on their activities covered under the permits issued by the Ministry of Energy. These reports may be periodic or one-time in nature. The Ministry of Energy develops standards for permissible raw gas flaring volumes, measurement, and calculation in accordance with Article 146. These standards should be observed in all reporting.

E. Measurement and Reporting

14. Measurement Frequency and Methods

Ministry of Energy Order 203, 2018,350 approves reporting rules for oil and gas as well as mineral operations. These rules are represented in annex tables and are developed in accordance with Article 132 of the Law on Subsoil and Subsoil Use, 2017, which lists the reports oil and gas licensees must submit. Article 145 calls for a unified state system of subsoil use management (a digital database). Article 16 of the Law on State Statistics, 2010351 gives administrative bodies the right to acquire statistical information.

15. Engineering Estimates

No details relating to engineering estimates could be identified in the relevant regulation, but industry reports suggest that companies report flare volumes based on meter readings or engineering estimates. According to one paper on flare reduction at the Kashagan field, operators have developed methodologies to estimate flare volumes as a backup to meter data.353 For emissions from flares, metered or calculated estimates are accepted, but Environmental Code, 2021 (see footnote 340) requires mandatory automated emissions monitoring for Category I facilities going forward.

16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted. However, industry reports suggest that operators must keep a log of metered flare volumes or estimates based on approved calculation methods. Flare meters collect data on continuous and intermittent flaring at the flare stack. The data should be entered in the unified state system of subsoil use management along with operational data. All flaring must be classified by location (onshore, offshore); duration, type of gas (sweet or sour); composition; cause of flaring (planned, unplanned); and source (tug number of the equipment, which is often a pressure relief valve).353

17. Data Compilation and Publishing

No evidence regarding data compilation and publishing could be found in the sources consulted. However, the annual reports of KazMunayGas include raw gas flaring volumes from KazMunayGas operations for the last several years.354

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

Both hydrocarbon and environmental regulators can impose penalties, the former for violating a flaring permit and the latter for violating an emissions permit. Penalties for violation of emission permits are more common.

Article 175 of the Environmental Code, 2021 (see footnote 340) authorizes MEGNR to assign daily monetary penalties. Interest is charged if payments are delayed or the offending party does not bring the operation into compliance within the specified time. According to Article 356 of the Code on Administrative Infractions, 2014, failure to perform the environmental requirements during subsoil use entails fines, the level of which depends on the size and income of the operator. In addition, environmental taxes are paid on all emissions, even when emissions are below the limits granted in permits. The penalties and taxes for stationary sources are paid to the local government at the location of the emission source, according to Article 577 of the Tax Code, 2017.355

Article 153 of the Law on Subsoil and Subsoil Use, 2017 (see footnote 337) authorizes the Ministry of Energy to penalize violators of subsoil use contract terms unless operators bring the operation into compliance within the designated period (up to six months depending on the violation). Subsoil use contracts capture approved project documents such as field development plans that must have gas utilization scope and flares. Paying penalties does not negate the obligation to bring the operation into compliance. The operator has the right to ask for an extension of the specified period for compliance, which must be approved by the Ministry of Energy after an expert review.

According to Article 356 of the Code on Administrative Infractions, 2014, flaring without a permit, except when allowed by law, or violation of permit conditions “shall entail a fine on subjects of small entrepreneurship in amount of 250, on subjects of medium entrepreneurship in the amount of 500, on subjects of large entrepreneurship in the amount of 2,000 monthly calculation indices.”356 Article 356 also lists penalties for hydrocarbon extraction without using and processing raw gas, violations of requirements in approved project documents, and environmental requirements. No evidence of penalties by the Ministry of Energy under these articles for violation of flare permits could be found.

19. Nonmonetary Penalties

Article 106 of the Law on Subsoil and Subsoil Use, 2017, provides for early termination of the subsoil contract under certain conditions, including violations of the contract terms. The operator can dispute the early termination decision in court within two months of receiving the notice. No case of contract termination based on a flare permit violation could be identified.
Kazakhstan

G. Enabling Framework

20. Performance Requirements

Article 202 of the Environmental Code, 2021 (see footnote 340) details the standards for permissible emissions. It also clarifies that these standards apply to all flares other than those deemed technologically unavoidable by the regulator, the Ministry of Energy. According to Article 200, local executive bodies have the power to “establish stricter environmental standards” for air emissions if local conditions warrant it. According to Article 39, emissions standards for facilities with an integrated environmental permit will be established on the basis of available techniques as determined by the new Bureau of Best Available Technologies (see section 13 of this chapter).

21. Fiscal and Emission Reduction Incentives

According to Article 127 of the Environmental Code, 2021, emission taxes are calculated using base levies for various emissions, including those from flares, provided in tax laws. For example, according to Article 576 of the Tax Code, 2017 (see footnote 356), base tax rates for emissions from flaring are 20–278 times as large as the same emissions from other stationary sources. Paragraph 8 of Article 576 states that local authorities may increase the tax rates up to 200 percent of the base rate, except for emissions from flares, which can be increased to more than 200 percent of the base rate.

Recent changes to the Tax Code align it with the Environmental Code, 2021. According to Article 575 of Law No. 402-VI, 2021, the base tax rates for emissions from stationary sources will be doubled from January 2025, and emissions from flaring will be assessed at the same rate as stationary sources. According to Article 130 of the Environmental Code, 2021, provides tax relief to facilities that obtain an integrated environmental permit through the adoption of the best available techniques (see section 13 of this chapter). Penalties will be heavier for facilities that do not adopt the best available techniques.

22. Use of Market-Based Principles

Kazakhstan initiated the first ETS in Asia in 2013. Phase II covered 2014 and 2015. Phase III was delayed until the establishment, in 2018, of an online platform for monitoring, reporting, and verifying GHG emissions. The Environmental Code was periodically updated to include GHG quotas and related obligations and standards to assist with the evolution of the ETS market. The Environmental Code, 2021, includes a more extensive coverage of GHG regulation and ETS compliance in Kazakhstan and covers an emits instead of only CO₂, which was the case in the early days of the ETS.

Operators of oil and gas installations with annual GHG emissions of more than 20,000 tCO₂e must obtain quotas. The penalty for noncompliance was waived in 2013 and 2014 but was about US$35/tCO₂e in 2021. Operators of installations with emissions of 10,000–20,000 tCO₂e a year must report emissions annually, although they are not required to participate in the ETS. The average 2020 price was about US$11 per tCO₂e. The 2021 ceiling under the National Allocation Plan is 159.9 million tCO₂e. The next plan is expected to cover five years.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

The Law on Gas and Gas Supply, 2012 (see footnote 338) supports the government’s policy of increasing gas use across the country to avoid wasting the country’s natural resources and replace coal and other fuels with higher emissions. The national gas system operator KogTransGas, wholly owned by KazMunayGas, is also trying to reduce fugitive emissions across its transmission and distribution network. Since 2018, KogTransGas has used remote methane sensing, which identified 3,963 leaks by the end of 2020. Fixing these leaks will reduce methane emissions and avoid waste of gas.

Article 15 of the Law on Gas and Gas Supply, 2012, establishes the preferential rights of the state to purchase raw or processed (“commercial”) gas assigned to the operator under the upstream contract. KogTransGas is responsible for procuring the gas from upstream operators. Article 15 stipulates that the raw gas price can include the cost of recovering raw gas, the cost of delivering it to a location where KogTransGas can take possession, and a profit margin of no more than 10 percent. The price of commercial gas can also include the cost of processing.

The National Energy Report, 2019, of the Kazakhstani Association of Oil, Gas, and Energy Sector Organizations (Kazenergy) suggests that the price paid by KogTransGas has not been sufficient to cover “the costs associated with recovering associated sour wet gas that must be gathered, processed, and transported to an injection point.” However, the price has been sufficient to cover the cost of delivering “shallow dry gas” to KogTransGas. According to the KogMunayGas 2020 Annual Report (see footnote 354), five operating companies, in which KogMunayGas is a partner, sell their gas to KogTransGas under Article 15 of the Law on Gas and Gas Supply, 2012, and five others, including the Tengiz, Karachaganak, and Hazhagen operations, sell gas directly to domestic and export markets or use it for re-injection or meeting their own heat and electricity needs.

The 2020 Annual Report of KogTransGas acknowledges the need to increase wholesale prices to ensure the commerciality of domestic gas sales. It refers to a ministerial meeting in August 2020 that called for an annual increase of 15 percent between 2021 and 2026. Although domestic gas sales are twice as large as export volumes, revenues from domestic sales accounted for only 6 percent of revenues in 2018, mainly because regulated prices of gas delivered to customers have been kept artificially low. Phased increases of transportation tariffs and retail prices, possibly based on netback pricing, are part of the strategic objectives of KogTransGas. Reforming gas pricing and sending the right price signals across the natural gas value chain is expected to provide incentives to reduce flaring further by offering a commercially viable alternative to upstream operators and serving the government’s gasification policy efficiently.

359 Article 575 of the Law on Gas and Gas Supply, 2012, and five others, including the Tengiz, Karachaganak, and Hazhagen operations, sell gas directly to domestic and export markets or use it for re-injection or meeting their own heat and electricity needs.
366 Article 15 of the Law on Gas and Gas Supply, 2012, establishes the preferential rights of the state to purchase raw or processed (“commercial”) gas assigned to the operator under the upstream contract. KogTransGas is responsible for procuring the gas from upstream operators. Article 15 stipulates that the raw gas price can include the cost of recovering raw gas, the cost of delivering it to a location where KogTransGas can take possession, and a profit margin of no more than 10 percent. The price of commercial gas can also include the cost of processing.
367 The National Energy Report, 2019, of the Kazakhstani Association of Oil, Gas, and Energy Sector Organizations (Kazenergy) suggests that the price paid by KogTransGas has not been sufficient to cover “the costs associated with recovering associated sour wet gas that must be gathered, processed, and transported to an injection point.” However, the price has been sufficient to cover the cost of delivering “shallow dry gas” to KogTransGas. According to the KogMunayGas 2020 Annual Report (see footnote 354), five operating companies, in which KogMunayGas is a partner, sell their gas to KogTransGas under Article 15 of the Law on Gas and Gas Supply, 2012, and five others, including the Tengiz, Karachaganak, and Hazhagen operations, sell gas directly to domestic and export markets or use it for re-injection or meeting their own heat and electricity needs.
Libya

5.97 billion cubic meters of gas flared in 2021 (total oil production 1,246 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th>Year</th>
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</thead>
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<tr>
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<td>128%</td>
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<td>2015-2020</td>
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Change in Flare Gas Intensity**

<table>
<thead>
<tr>
<th>Year</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>-14%</td>
</tr>
<tr>
<td>2015-2020</td>
<td>8%</td>
</tr>
</tbody>
</table>

Note: Data are used in this report based on global flaring data estimated by the Global Gas Flaring Reduction Partnership (GGFR) using satellite data from the Colorado School of Mines. This approach is applied to all countries covered in this report in a consistent manner.


A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Oil production in Libya has fluctuated wildly in recent years. Between 2012 and 2021, daily oil production averaged 0.8 million barrels, ranging from 0.4 million to 1.4 million barrels. The volume of gas flared correspondingly fluctuated, falling from 5.9 bcm in 2012 to 2.4 bcm in 2016, declining sharply to 2.5 bcm in 2020, and increasing again to 6 bcm in 2021 (figure 12). The flaring intensity during this period fluctuated, reaching its highest level in 2020, but then dropping again in 2021 on the back of an increase in oil production. Of the countries covered in this review, the flaring intensity in Libya in 2021 ranked fourth. There were 86 individual flare sites in the last flare count, conducted in 2019.

With the establishment of the Technical Centre for Protection of the Environment in the early 1980s, Libya was among the first North African countries to establish a government agency tasked with protecting the environment. The agency was later renamed the Environment General Authority and given additional responsibilities and powers. Until recently, it acted as an independent and autonomous institution; after recent changes in the government, it now reports directly to the Ministry of the Environment.

Libya ratified both the Paris Agreement and the Kyoto Protocol but has not yet submitted an NDC to the UNFCCC. It is undergoing substantial political changes following the formation of a new government. These changes may have a significant impact on the oil and gas sectors and environmental management. Therefore, the government’s approach to gas flaring and venting, including the regulation and regulatory practices currently in place, is subject to change.

2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Following multiple updates, Law no. 25, the Petroleum Law, 1955 (Petroleum Law, 1955, hereafter) forms the basis for all technical, commercial, and environmental aspects of petroleum activities in Libya. Law no. 24, 1970 established the National Oil Corporation (NOCORP). Annex 2 of the Petroleum Law, 1955, contains a model petroleum concession contract that outlines how the commercial and operational principles of early petroleum licenses are to be regulated. The document does not mention specifics related to associated gas, flaring, or venting. Crucial aspects relating to the handling of associated gas are covered in confidential licensing agreements between the government and license holders.

The Model Production Sharing Contract, 2006, mentions the use and disposal of associated gas, but much is left to the notion of compliance with the Good Oilfield Practices, as defined in the model PSC. The model PSC only forms the basis for negotiations between the NOCORP and license holders. The PSCs are individually negotiated and may differ in detail, although they must all comply with the Petroleum Law, 1955. All but one concession agreement have reportedly been renegotiated and converted to PSCs.

Law no. 15, the Environment Law, 2003 (Environment Law, 2003, hereafter) is an update of the original Law no. 7, Protection of the Environment, 1982. It is a larger and protecting the environment, specifically relating to water, soil, air, and food.
Libya

4. Legislative Jurisdictions

Hydrocarbon and environmental matters are subject to national laws and jurisdiction. Flaring and venting are not directly regulated.

5. Associated Gas Ownership

All subsurface oil and gas resources are the property of the Libyan state, according to Article 1 of the Petroleum Law, 1955. Licenses in Libya were originally structured as concessions, but PSCs have become the norm with the introduction of the model Exploration and Production Agreement starting in 2006. In PSCs, title to the contractor’s share of the production is transferred in the form of a payment or royalty. The contractor has the obligation to meet production targets and is subject to change.

The information provided in this and the next sections is therefore subject to the approval of the government.

6. Regulatory Authority

The formation of a new government in early 2021 has affected the regulatory structure for gas flaring and venting. The establishment of the Ministry of Oil and Gas and the Ministry of the Environment is likely to be relevant to flaring and venting. At the time of writing, not all changes had been fully implemented.

The information provided in this and the next sections is therefore subject to change.

Within the oil and gas sector, responsibilities are clearly allocated to the minister of oil and gas, who oversees the Petroleum Committee. The ministry also influences the Management Committee supervising the PSCs. The Ministry of the Environment, and also chairs it.

The Environmental General Authority was established as an independent and autonomous institution with its functions and responsibilities laid out in the Environment Law, 2003 (see footnote 367). Following recent changes in the government, the Ministry of the Environment was established. It has assumed responsibility for, and control of, the Environmental General Authority.

7. Regulatory Mandates and Responsibilities

According to Article 2 of the Petroleum Law, 1955 (see footnote 367), the Petroleum Committee recommends key decisions on such matters as granting, assigning, renewing, relinquishing, and canceling licenses and concessions to the minister of oil and gas, who ratifies the decisions. The Petroleum Committee also appoints the director of the Environmental Authority, with whom it shares monitoring and inspecting powers. The responsibilities of the director of the petroleum committee also cover operational aspects with the license holders, such as tracking exploration activities, approving fiscal assessments, and reviewing technical reports.

However, until recently, NOCORP had far-reaching regulatory powers and assumed regulatory functions assigned to the ministry and the Petroleum Committee. Following recent changes in the government, the Ministry of Oil and Gas was reestablished with regulatory powers over the oil and gas industry and authority over NOCORP. The role of the director of petroleum affairs remains essentially unchanged.

The Management Committee, comprising members from NOCORP (which chairs the committee) and license holders, manages PSCs and can issue decisions that are binding on operators. They predominantly cover compliance with the existing regulations for the Good Oilfield Practices, and the commerciality assessment of associated gas not used in petroleum operations, referred to as excess associated gas in Article 1 of the Model Production Sharing Contract, 2006 (see footnote 369). All commercial aspects of the PSCs are subject to negotiation between NOCORP and the contractors.

When it comes to environmental matters such as air emissions, the Environment Law, 2003 (see footnote 370) empowers the Environmental General Authority with monitoring and inspection. These powers could also entail flaring- and venting-related matters, although NOCORP is better positioned to cover environmental matters and private sector counterparts, issues with which it has extensive experience.

8. Monitoring and Enforcement

Article 2 of the Petroleum Law, 1955, empowers the Ministry of Oil and Gas (mostly through the director of petroleum affairs) to access production-related data. The ministry can also visit production facilities to ensure that operations are being conducted in line with the Good Oilfield Practices, as per Article 11. In cases of noncompliance with the requirements stipulated in the petroleum concession, the license can be revoked, as per Article 18. Article 25 of the Model Production Sharing Contract, 2006, allows for termination of a PSC if there has been a material breach of the obligations or a failure to remedy the breaches in question.

The Environment Law, 2003, gives the Ministry of the Environment (and the Environmental General Authority under it) the right to monitor pollution levels and require emission permits for facilities covered by the regulation.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Neither the Petroleum Law, 1955 (see footnote 367) nor the Model Production Sharing Contract, 2006 (see footnote 369) explicitly bans or allows flaring or venting of associated gas. Article 13 of the Model Production Sharing Contract requires disposal of noncommercial associated gas in accordance with the Good Oilfield Practices. The Management Committee decides whether excess associated gas is classified as commercial or noncommercial.

10. Authorized Flaring or Venting

See the previous section.

11. Development Plans

Article 13 of the Model Production Sharing Contract, 2006, requires the Management Committee to approve the development plan for any excess associated gas deemed commercial.

12. Economic Evaluation

Article 13 of the Model Production Sharing Contract, 2006, assigns the commerciality assessment of excess associated gas to the Management Committee. If the gas is not commercial, NOCORP can exercise the right to take the gas free of charge after separating it from oil.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

According to Article 13 of the Model Production Sharing Contract, 2006 (see footnote 369), metering is required only for excess associated gas in commercial discoveries. Article 2 of the Petroleum Law, 1955 (see footnote 367) allows the Director of Petroleum Affairs to inspect meters to ensure accuracy.

14. Measurement Frequency and Methods

No evidence regarding measurement frequency and methods could be found in the sources consulted.

15. Engineering Estimates

No evidence regarding engineering estimates could be found in the sources consulted.

16. Record Keeping

Article 5 of the Model Production Sharing Contract, 2006, requires the operator to maintain operational records (daily and monthly) in line with the Good Oilfield Practices, which also cover excess associated gas in commercial discoveries. There is no requirement to maintain logs for flared or vented gas volumes.

17. Data Compilation and Publishing

No evidence regarding data compilation and publishing could be found in the sources consulted. However, the Ministry of Oil and Gas is producing overall oil and gas volume reports (not specific to flaring and venting), which are shared with the oil and gas operators active in the country.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

No evidence regarding monetary penalties could be found in the sources consulted.
19. Nonmonetary Penalties

Article 18 of the Petroleum Law, 1955 (see footnote 367) states that license revocation is possible for reasons stated in the bilateral commercial agreements with NOCORP. Article 5 of the Model Production Sharing Contract, 2006 (see footnote 369) requires operators to conduct all petroleum operations diligently and in line with the applicable petroleum and environmental laws and the Good Oilfield Practices. Article 25 allows for the termination of a PSC in the case of a material breach of the contractual obligations, provided that remedies have not been started within 90 days following the receipt of the formal notice. No evidence could be found of license revocation due to poor flaring and venting practices.

G. Enabling Framework

20. Performance Requirements

No evidence regarding performance requirements could be found in the sources consulted. However, the main performance standards stipulated in the key pieces of regulation revolve around the Good Oilfield Practices, as defined in Article 1 of the Model Production Sharing Contract, 2006 (see footnote 369).

21. Fiscal and Emission Reduction Incentives

No evidence regarding fiscal and emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

Article 13 of the Model Production Sharing Contract, 2006, asks the private and public parties involved to use any surplus capacity in processing and transport facilities for excess associated gas, but this request does not constitute a formal requirement.
Malaysia

2 billion cubic meters of gas flared in 2021 (total oil production 510 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
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<tr>
<th>Year</th>
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</tr>
</thead>
<tbody>
<tr>
<td>%</td>
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<td>-35%</td>
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Change in Flare Gas Intensity**

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<th>2015-2021</th>
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</tr>
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<tbody>
<tr>
<td>%</td>
<td>-31%</td>
<td>-24%</td>
</tr>
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* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 13 Gas flaring volume and intensity in Malaysia, 2012-21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Between 2012 and 2021, oil production in Malaysia rose and peaked in 2016 before falling to the lowest level in 2021, significantly lower than that in 2012. The volume of gas flared fell to its lowest level in 2021, but due to the even more significant decline in oil production, the flaring intensity did not fully track this significant downward movement (figure 13). There were 56 individual flare sites in the last flare count, conducted in 2019.

Malaysia has ratified both the Paris Agreement and the Kyoto Protocol. It submitted its first NDC to the UNFCCC in 2016 and an update in 2021. Malaysia has committed to reducing its carbon intensity (GHG emissions as a percent of GDP) relative to 2005. The updated NDC increased the unconditional contribution for carbon-intensity reduction from 35 percent in the 2016 submission to 45 percent. All seven GHGs are covered, but flaring and venting are not mentioned in the NDC, even though it notes the importance of the oil and gas industry as a key sector of the Malaysian economy.

Malaysia has historically taken a strategic approach to domestic energy issues, starting with the National Petroleum Policy, 1975 (efficient utilization of petroleum resources), the National Energy Policy, 1979 (efficient utilization of energy and elimination of wasteful and nonproductive use), and the National Depletion Policy, 1980 (prolonging the life span of the nation’s oil and gas reserves). It has continued adjusting and expanding these policies with follow-up initiatives. At the macroeconomic level, successive Malaysia Plans have aimed to put the country, its people, and economy on a growth trajectory. These aims include sustainable growth and the reduction of GHG emissions, with tCO₂e a year per unit of GDP as a sustainable consumption and production indicator.

Despite the focus on sustainable development and environmental protection across these key government initiatives, no regulations or government policies explicitly cover gas flaring and venting. Instead, these topics are treated in confidential documents, such as the production and operations procedures and guidelines, and licensing arrangements, such as PSCs and risk service contracts.

2. Targets and Limits

There is no evidence of any specific government-imposed flaring or venting-related targets or limits in the sources consulted. However, the National Oil Company Berhad (Petronas), the national oil company, has publicly pledged to reach net-zero carbon emissions by 2050. It will do so by deploying (among other levers) its operational strengths to reduce gas flaring and venting, capture methane emissions, and optimize production operations.

B. Legal/Regulatory Framework and Contractual Rights


The Environmental Quality Act, 1974, established the principles of environmental protection. It is supported by the Environmental Qual...
Malaysia

Quality (Clean Air) Regulation, 2014,\(^{382}\) and the Environmental Quality (Prescribed Activity) (Environmental Impact Assessment) Order, 2015.\(^{383}\) The limitations set on air pollutants also apply to oil and gas operations across upstream, midstream, and downstream operations.

The Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009,\(^{384}\) is an intercountry agreement governing production operation procedures in shared areas. It sets ground rules for flaring and venting. The requirements for exemptions from these rules appear comparable to those stipulated in confidential arrangements with contractors and operators.

The Petronas Procedures and Guidelines for Upstream Activities (PPGUA)\(^{385}\) state detailed country-specific requirements, including the key provision that upstream activities are to be carried out in line with good and modern petroleum practices, including flaring and venting. Although not a regulation, these guidelines carry significant weight, given the influence of Petronas as the hydrocarbon resource owner with a direct reporting line to the prime minister.

C. Regulatory Governance and Organization

6. Regulatory Authority

The Petroleum Development Act, 1974, vests the powers and responsibilities over hydrocarbon resources in Petronas. Petronas is under the control and direction of the prime minister (Section 3 of the Petroleum Development Act, 1974). The prime minister also has the power to make regulations relating to the exploration and exploitation of hydrocarbons (Section 7), which he or she may delegate (Section 7A). The Malaysia Petroleum Management (MPM) within Petronas carries out the regulatory responsibilities assigned to Petronas, making it the upstream regulator in Malaysia.

Based on the Environmental Quality Act, 1974, the minister of environment and water is responsible for managing the environment and limiting waste, emissions, and other environmentally adverse factors. In line with Section 3, he or she appoints the director-general of environmental quality, who administers the provisions of the Environmental Quality Act, 1974, the Environmental Quality (Clean Air) Regulation, 2014 (see footnote 382); and other laws and regulations. On issues such as emission management, the responsible Petronas department (MPM for upstream activities and the health-safety-environment department for activities covering all business lines) typically liaises with the director-general of environmental quality.

7. Regulatory Mandates and Responsibilities

The MPM is in charge of production-licensing arrangements with external companies, including the terms of contracts; controls the work programs and budgets; and oversees compliance with guidelines and regulations. As flaring- and venting-related matters are captured in the PPGUA (typically referred to in confidential licensing arrangements), the MPM has significant influence over the treatment of associated gas.

Based on the responsibilities vested in the minister of environment and water, according to Section 3 of the Environmental Quality Act, 1974, its subordinate director-general of environmental quality can issue emission licenses and carry out monitoring activities and assessments across upstream, midstream, and downstream operations. Given the MPM’s authority over upstream operations, it can be assumed that any upstream-specific action will be carried out in close coordination.

8. Monitoring and Enforcement

By monitoring the implementation of the PPGUA, the MPM gains insights into the remaining lifecycle of upstream activities, including the use of associated gas, across the country’s portfolio. The MPM can set gas supply targets for the operator and conduct quarterly performance reviews. It also sets annual flaring or venting limits. If these limits are exceeded, the operator needs to notify the MPM and provide a mitigation plan. The MPM can then, at its sole discretion, issue an exemption. Noncompliance can lead to legal and financial consequences.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Section 10 of the Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009 (see footnote 384) bans flaring and venting without prior approval except in the following circumstances:

- during well cleaning and testing periods (not exceeding 48 hours)
- in emergencies, such as shutdowns or pressure relief
- during maintenance (not exceeding one week)
- during temporary equipment failure (not exceeding 72 hours)
- during gas release from facilities when alternative uses of gas are not economic

10. Authorized Flaring or Venting

Section 10 of the Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009, in alignment with the requirements of the PPGUA, requires prior approval of any flaring or venting other than those that occur under conditions listed in the preceding section. The PPGUA gives the MPM the authority to set gas supply targets and approve plans for associated gas. Any planned flaring or venting requires justification.

11. Development Plans

The PPGUA provides guidance regarding the field development plan and its review and approval, including the arrangement for any potential gas flaring system in the overall development. As a key principle, all new developments must be designed for zero continuous flaring and venting.

Section 34 of the Environmental Quality Act, 1974, in conjunction with the First Schedule of the Environmental Quality (Prescribed Activity) (Environmental Impact Assessment) Order, 2015 (see footnote 383) entitles the minister of environment and water to ask for an EIA for upstream oil and gas developments, including pipeline and storage construction plans (no requirements for installations specific to flaring and venting). The director-general of environmental quality reviews and approves or rejects the development plans based on the submitted report. In case of rejection, a resubmission with an improved development concept is typically allowed.

12. Economic Evaluation

No evidence regarding economic evaluations could be found in the sources consulted.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

The PPGUA provides guidance regarding minimum technical requirements and the approval process for metering systems. Flaring and venting volumes need to be reported, in line with measurement requirements, every month (see Section B of this chapter).

In line with Section B of the Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009 (see footnote 384), the license holder must maintain production reports, including volumes of flared and vented gas, and submit them to the authorities. Sections 12–15 also detail metering and measurement requirements.
14. Measurement Frequency and Methods
According to Section 8 of the Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009, the license holder must keep daily operations logs and measure production daily and monthly. Section 14 states that the metering system should be in accordance with the standards of the American Gas Association or the American Petroleum Institute.

15. Engineering Estimates
No evidence regarding engineering estimates could be found in the sources consulted.

16. Record Keeping
In line with Section 8 of the Malaysia-Thailand Joint Authority Procedures for Production Operations, 2009, the license holder must keep the records of the operations logs and production reports for at least a year.

17. Data Compilation and Publishing
In its annual and biannual sustainability reports, Petronas publishes flaring and venting data. In its role as Malaysia’s national oil company, it also provides country-wide data for NDC purposes.

F. Fines, Penalties, and Sanctions
18. Monetary Penalties
Following Section 7 of the Petroleum Development Act, 1974, any violation of the act’s provisions can be sanctioned with imprisonment or fines. Section 29 of the Environmental Quality (Clean Air) Regulation, 2014 (see footnote 382) provides for imprisonment or fines for violations of the Environmental Quality Act, 1974. The PPGUA is aligned with the above provisions, in that any noncompliance with their guidelines, including the provisions on flaring and venting, can lead to legal and financial consequences. No evidence could be found in the sources consulted that these provisions have been explicitly applied to flaring or venting-related contraventions.

19. Nonmonetary Penalties
Termination clauses are typically covered in the PSCs and risk service contracts, none of which is publicly available. They state that any noncompliance with the MPM requirements (including the PPGUA) can be sanctioned. Section 24 of the Environmental Quality (Clean Air) Regulation, 2014, gives the director-general of environmental quality the right to issue a prohibition order to discontinue operations, if necessary, to safeguard public health, safety, or welfare. Section 22 allows the director-general to impose additional requirements on operations or take any other appropriate measure deemed necessary.

G. Enabling Framework
20. Performance Requirements
The Third Schedule of the Environmental Quality (Clean Air) Regulation, 2014 (see footnote 382) on limit values and technical standards, covers the midstream and downstream oil and gas sectors but not the upstream sectors.

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal and emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
Section 1 of the Gas Supply Act, 1993 (see footnote 379) regulates gas supply to consumers through pipelines. The processing or refining of petroleum or manufacturing of petrochemical products from petroleum is reserved for Petronas. Any exception requires the prime minister’s approval (Section 6 of the Environmental Quality Act, 1974). There is no evidence in the sources consulted that any exceptions or privileges for using associated gas have been granted.
Mexico

6.51 billion cubic meters of gas flared in 2021
(total oil production 1.735 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th></th>
<th>2015-2021</th>
<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>30%</td>
<td>15%</td>
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</table>

Change in Flare Gas Intensity**

<table>
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<tr>
<th></th>
<th>2015-2021</th>
<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>73%</td>
<td>55%</td>
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</tbody>
</table>

Note: These data are known in this report based on flare data estimated by the Mexican Gas Flaring Reduction Partnership (MGGFR) using satellite data from the Colorado School of Mines. This approach is applied to all countries covered in this report in a consistent manner.

* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 14 Gas flaring volume and intensity in Mexico, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Between 2012 and 2021, oil production in Mexico fell by one-third, but the volume of gas flared increased by one-third and the flaring intensity more than doubled (figure 14). While the volume of gas flared shows an upward trend since 2016, oil production remained largely stable, leading to a corresponding increase in flaring intensity. There were 115 individual flare sites in the last flare count, conducted in 2019.

In 2016, Mexico endorsed the Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). Mexico also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 30). In its updated NDC submitted to the UNFCCC in December 2020,387 Mexico committed to unconditional contributions of a 22 percent reduction in GHG emissions and a 51 percent reduction in black carbon by 2030 compared with a business-as-usual scenario.

In 2016, the National Hydrocarbons Commission (Comisión Nacional de Hidrocarburos [CNH]) set guidelines for the national oil company Petróleos Mexicanos (Pemex) to reduce flaring. The guidelines were expected to be enforced over the coming years. However, the upstream sector’s lack of financial resources and investment priorities have prevented major projects from being implemented.

In June 2016, Mexico joined the United States and Canada in calling for a 40–45 percent reduction in methane emissions from their oil and gas sectors by 2025. In November 2018, Mexico’s Agency for Safety, Energy and Environment (Agencia de Seguridad, Energía y Ambiente [ASEA]) released the Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbon Sector. DOF: 06/11/2018.388 to meet this target. ASEA’s guidelines require new and existing facilities across the value chain to meet facility-wide emission limits.

In 2016, Mexico’s Agency for Safety, Energy and Environment (Agencia de Seguridad, Energía y Ambiente [ASEA]) released the Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbon Sector. DOF: 06/11/2018.388 to meet this target. ASEA’s guidelines require new and existing facilities across the value chain to meet facility-wide emission limits.

2. Targets and Limits

Article 14 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons, DOF: 07/01/2016389 specifies the methodologies and criteria for operators to structure their associated gas utilisation programs and targets. For exploration, the operator indicates the volumes of associated gas that can be utilised given existing technologies, infrastructure, and knowledge of the fields to be explored. The CNH then reviews the associated gas utilisation program to establish the targets to be applied throughout the exploration stage. For production, the operator needs to achieve and maintain an annual utilisation rate for associated gas of 98 percent. The target must be reached within three years of the start of operations. The operator should detail the actions and investments needed to achieve and maintain the target annually. The CNH reviews the proposed targets and utilisation program, and where appropriate, modifies and establishes the final targets to be implemented throughout the production stage.

Article 15 permits operators to propose an adjusted gas utilisation program to the CNH if field conditions make it uneconomic to reach the authorized targets after the initial three-year period. The CNH may adjust the initial target to maximise crude oil and natural gas production over the long term under economically viable conditions.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

In 2008, the Mexican Congress issued the Law of the National Hydrocarbon Commission, DOF 11/28/2008.390 Article 3 assigns responsibility for regulating the use of natural gas to minimise gas flaring and venting in oil and gas exploration and production to the CNH. Article 43 of the Hydrocarbons Law, 2014.391 affirms the CNH’s responsibility for overseeing the use of associated natural gas.

Law, 2014, assignments, and contracts. CNH technical provisions regulate the use of natural gas.

Energy Regulatory Commission (Comisión Reguladora de Energía), formula) can be established in the contract or determined by the of production on the market. The gas price (often linked to a form of cost and profit oil and gas. Under a license contract, the to a part of the production is transferred to the contractor in the

5. Associated Gas Ownership

Article 1 of the Hydrocarbons Law, 2014, vests the “perpetual” ownership of subsoil oil and gas in the state. Article 4 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons states that associated natural gas is the property of the state and that its production is subject to the terms established in the Hydrocarbons Law, 2014, assignments, and contracts. CNH technical provisions regulate the ownership of extracted oil and gas.

According to the Hydrocarbons Income Act, 2014, PSCs and license contracts, the two main forms of agreements in Mexico, regulate the ownership of extracted oil and gas. Under PSCs, title to a part of the production is transferred to the contractor in the form of cost and profit oil and gas. Under a license contract, the contractor owns all extracted oil and gas and can sell its share of production on the market. The gas price (often linked to a formula) can be established in the contract or determined by the Energy Regulatory Commission (Comisión Reguladora de Energía), Article 10 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (see footnote 391) states that gas venting is allowed only for safety reasons in emergency cases. Article 6 specifies that the flaring of associated natural gas is allowed during well testing (as long as it is included in the exploration or development plans approved by the CNH), in situations that pose safety threats, and when productive use is not viable (as shown by the technical-economic analysis required in Article 11 and approved by the CNH). Article 21 requires operators to notify the Commission when they have carried out flaring during well tests. The notification should be sent within 48 hours of the test. If emergency gas venting occurs, ASEA must be informed of the volume vented. The volume of gas flared or vented must adhere to the provisions issued by the CNH based on the gas utilization program. The CNH website includes an example of the implementation experience in the Tepetate field.

According to Article 10 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons, the authority to flare associated gas is included in the exploration or development plan’s approval according to detailed instructions in Articles 14 and 15. Articles 18–27 of the Regulation of the General Law of Ecological Balance and Environmental Protection in the Field of Prevention and Control of Atmosphere Pollution, 2014, require certain stationary sources—those that emit or may emit odors, gases, solid particles, or liquid particles into the atmosphere—to obtain operating licenses, which SEMARNAT issues by for an indefinite term, and outline the requirements and steps involved in the license application. For the oil and gas sector, the license application is made to ASEA.

11. Development Plans

Article 44 of the Hydrocarbons Law, 2014 (see footnote 391) requires oil and gas producers to seek approval from the CNH for exploration and development plans. The CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons require the treatment of associated natural gas, including flaring, to be specified in exploration and development plans. According to Article 5 of the CNH Technical Provisions, the operator may utilize the associated natural gas for the needs of the operation such as fuel for turbines, or pneumatic pumping or other lifting systems that require gas injection. Alternatively, gas can be conserved through re-injection or transferred to another contract area or third party via a commercial transaction.

Article 10 requires the operator to submit to the CNH a program to use associated gas as part of the development plan for each assignment and contract containing the following information:

- a technical-economic analysis
- the volume of associated gas to be used
- a description of the actions and investments for the use, conservation, transfer, and, when necessary, flaring, including a general description of facilities and equipment dedicated to flaring or its use, identifying its location, available measurement systems, and maintenance procedures
- a schedule of well tests to be performed
- the operational performance indicators, which must detail the

Mexico's oil and gas sector is also subject to the General Law on Ecological Equilibrium and Environmental Protection, 2021, and other technical environmental standards issued by the Ministry of Environment (Secretaría de Medio Ambiente y Recursos Naturales [SEMARNAT]) and ASEA. They may impose additional conditions on flaring and venting as part of the approval of the environmental license for upstream petroleum activities.

ASEA Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector (see footnote 388), issued as part of Mexico's international climate commitments, prohibit gas venting, except in emergencies.

4. Legislative Jurisdictions

Gas flaring is a matter of national jurisdiction. Article 95 of the Hydrocarbons Law, 2014, vests the regulatory oversight of the oil and gas sector exclusively in the federal government.

7. Regulatory Mandates and Responsibilities

The mechanisms for controlling and permitting flaring and venting are within the remit of the CNH. In carrying out its role, the CNH draws on the hydrocarbon policy, the National Energy Strategy, and the programs issued by SENER, the head of which is the chair of Pemex’s board of directors. Historically, Pemex was the only gas producer in Mexico. The CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons prescribe new methods for measuring gas flaring and venting and attempt to promote gas utilization beyond re-injection.

ASEA can impose conditions related to flaring and venting when issuing an environmental license. These conditions focus on preventing and mitigating GHG emissions under Articles 8 and 12 of the General Law of Climate Change (RGLCC Regulation), 2014. ASEA Law, 2014, extends the need for an EIA to construct and operate facilities across the oil and gas value chain, including production, processing, transportation, refineries, and petrochemicals. ASEA can mandate operators to fix sources of polluting emissions, including those in the oil and gas sector. The law also provides for interinstitutional coordination. Additionally, every contractor is required to submit an EIA and obtain approval from ASEA, granted in an environmental license, before initiating operations.

8. Monitoring and Enforcement

Articles 1–4 of the Law of the National Hydrocarbon Commission empower the CNH to implement the measures necessary to monitor and audit the oil and gas industry. The CNH can supervise, verify, monitor, and, where appropriate, certify compliance with the law’s provisions. Sanctions can be applied in line with the Hydrocarbons Law, 2014 (see footnote 391). The CNH may also accredit third parties to supervise, inspect, and verify activities.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 4 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (see footnote 398) states that gas venting is allowed only for safety reasons in emergency cases. Article 6 specifies that the flaring of associated natural gas is allowed during well testing (as long as it is included in the exploration or development plans approved by the CNH), in situations that pose safety threats, and when productive use is not viable (as shown by the technical-economic analysis required in Article 11 and approved by the CNH). Article 21 requires operators to notify the Commission when they have conducted flaring during well tests. The notification should be sent within 48 hours of the test. If emergency gas venting occurs, ASEA must be informed of the volume vented. The volume of gas flared or vented must adhere to the provisions issued by the CNH based on the gas utilization program. The CNH website includes an example of the implementation experience in the Tepetate field.
Mexico

name and formula of the indicator, frequency of measurement, targets, and measurement parameters. The programs must include month-by-month forecasts for associated gas use during the first three years and annual forecasts thereafter. The CNH website provides examples of development plans that include approved associated gas use programs. One example is contract CNH-M4-ÉBANO/2018.411

12. Economic Evaluation

Article 6 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons allows flaring only when technical and economic analysis shows that it is the only viable option. Article 11 requires operators to conduct a technical and economic analysis to develop alternatives for the use of associated gas, to be carried out in line with the target established and the criteria detailed in Articles 4 and 5 of the Technical Provisions. The analysis should consider the composition and volume of the gas; the proximity of the processing, transportation, and distribution infrastructure; the value of the gas; and the necessary investments to utilize it. The guidelines contain case-by-case evaluation elements. The regulator and operator are expected to work together to find the best solution for a particular field. Any modifications operators propose to their associated natural gas utilization program need to be supplemented with an update of the technical and economic analysis, justifying the actions, alternatives, and where appropriate, a new target to be adopted.

Article 7 requires operators to maintain the financial resources to cover any damages caused by flaring. The allowed amounts of flaring are determined according to the Hydrocarbons Law. 2014 (see footnote 339) or the project-related contracts. The CNH website provides examples of implementation experience. Two examples are the Tierra Blanca404 and the Muro405 fields. Between 2007 and 2009, Pemex’s gas flaring and venting levels increased substantially, triggering efforts to reduce emissions, particularly in the Northwest Marine Region (in the Cantarell deposit). In December 2009, the CNH promulgated Resolution CNH. 06/01/09, 200944 prescribing procedures and techniques to reduce and prevent gas flaring and venting in hydrocarbon exploration and production. Under these guidelines, Pemex was required to submit to the CNH for its approval oil impact statements for its new projects using the most appropriate technologies. Noncompliance with these guidelines triggered sanctions. The regulation is mainly performance-based and requires Pemex to identify and evaluate feasible options for developing new facilities and increasing associated gas utilization. The guidelines expressly require Pemex to provide an economic evaluation and implementation strategy for re-injection and on-site power generation using the cost of utilitization treatment equipment as a factor of analysis.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Article 16 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (see footnote 398) requires the operator to follow the standards established in the CNH Technical Guidelines in Hydrocarbon Measurement, 2015,407 for measuring and reporting the volumes of the associated natural gas used. These guidelines were subsequently updated in February 2016,408 August 2016,409 and December 2017.410

Articles 23 and 24 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons require the operator to provide quarterly reporting of progress in implementing the associated gas use programs. The report should follow the CNH format outline411 and include the volumes of associated gas used, justification for any deviations from the gas use program, and a summary of unscheduled events that had resulted in gas flaring. Article 25 requires the CNH to review the quarterly reports within 15 business days of receipt and authorizes the CNH to request additional information from the operator. Article 26 requires operators to report monthly the associated natural gas balance per the provisions of the CNH Technical Guidelines in Hydrocarbon Measurement. The information should be submitted following a format found in the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (CNH 17/005/2019).

The ASEAs Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector (see footnote 388) requires operators to identify the source and quantify the volume of methane emissions. The information must be reported annually.

14. Measurement Frequency and Methods

Article 10 of the CNH Technical Guidelines in Hydrocarbon Measurement, 2015,407 requires daily and monthly reporting of oil and gas measurements to the CNH for the following:

- the daily volume and quality of production, disaggregating the average output of oil, condensate, gas, and water
- the volume of hydrocarbons extracted per oilfield, if applicable
- the hydrocarbon balance from the well and, if applicable, from the oilfield to the measurement point
- the volume of natural gas used or flared
- the volume of natural gas vented in exceptional circumstances.

Article 16 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons requires that, for the measurement and reporting of associated natural gas volumes, operators consider the conditions of pressure and temperature as well as the standards in the existing measurement guidelines issued by the CNH. Article 24 states that the program is monitored through quarterly reports provided by the operator to the CNH. These quarterly reports are available on the CNH’s website.

Article 25 of the CNH Technical Guidelines in Hydrocarbon Measurement, 2015,407 requires the operator to measure and report to the CNH the volume of natural gas produced, used, re-injected, flared, and vented. Natural gas used should be measured directly through flow meters. The uncertainty levels for measuring natural gas from flaring may not exceed 5 percent. However, when the use and re-injection have fiscal or commercial implications, the measurement uncertainty levels are limited to 1 percent. If natural gas is vented for exceptional reasons, the operator should report such venting to the CNH. In all cases, the chemical composition of the gas should be determined, either by sampling and laboratory analysis or by using installed continuous analyzers.

15. Engineering Estimates

The CNH Technical Guidelines in Hydrocarbon Measurement, 2015, require an indirect gas volume estimation to be made in accordance with gas-to-oil ratio accounting or by using a system balance or simulation. According to the ASEAs Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector (see footnote 388), the volumes of methane emitted may be calculated or measured, but in all cases, the operator must provide a technical justification for the choice of the methodology applied. If quantification involves calculations, it may be based on the following:

- material balance;
- mathematical models
- engineering calculations
- equipment emission factors established by the manufacturer.

16. Record Keeping

Article 33 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (see footnote 398) requires the operator to make available to the CNH at all times any information and documents related to the use of associated gas, including the equipment and instruments used. This information should be retained for five years from the effective date of the assignment or the corresponding contract. Article 21 of ASEAs Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector (see footnote 388) requires the maintenance of records related to methane-emitting components and activities at facilities for five years.
Mexico

17. Data Compilation and Publishing
The CNH compiles data submitted by operators on flaring and venting for public disclosure on the website of the CNH’s Hydrocarbon Information System. Information on gas use demonstrates the raising volumes of gas that have not been used in operations or marketed in recent years. Since late 2020, the percentage of gas used fell below 90 percent, well below the 98 percent target (see section 2 of this chapter).

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
Article 7 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons states that flaring of associated gas, a nonrenewable resource, outside of the approved utilization program would cause an economic loss to the nation and that operators must have the necessary financial resources to cover such losses. This compensation is in addition to any penalties that may be imposed under other laws and regulations. Article 34 provides that, based on monitoring and supervision, the CNH may initiate a sanctioning administrative procedure to determine whether there was noncompliance with the technical provisions. Article 35 provides that violations of these provisions will be sanctioned in accordance with Articles 85–87 of the Hydrocarbon Law. 2014 (see footnote 391) or specific contracts.

According to Article 85 of the Hydrocarbon Law, 2014, the seriousness of the violation will be considered when determining a sanction. SENER sanctions noncompliance with the terms and conditions established in the assignments and contracts, with a fine of 15,000–75,000 times the minimum wage. Operators failing to comply with an exploration plan or production development plan will be penalized with a fine of 150,000–3 million times the minimum wage. In the case of oil and gas development and production activities that do not have a measurement system approved by the CNH, a fine of three-six million times the minimum wage may be levied. The application of sanctions and payments are regulated by the Federal Law of Administrative Procedure. 2018.415 Article 25 of the AESA Law, 2014 (see footnote 400) also provides for penalties up to 3 million times the minimum wage depending on the severity of the violation of the environmental mandates.

19. Nonmonetary Penalties
No specific nonmonetary penalties for flaring or venting were found. However, Article 85 of the Hydrocarbon Law, 2014, states that within the scope of their oversight, SENER and the CNH should sanction serious or repeated violations of the Hydrocarbon Law with suspension or revocation of contracts or removal or disqualification of the personnel who provided their services to an operator, assignee, or contractor. Article 70 of the Federal Law of Administrative Procedure, 2018, states that administrative sanctions should be provided in the respective laws and may consist of the following:

• warning
• fine
• additional fine for each day the violation persists
• detention for up to 36 hours
• temporary or permanent closure, partial or total closure of facilities
• others indicated by the laws or regulations.

Article 99 of the Regulation of Hydrocarbons Law, 2014,416 details the procedures and timelines the administrative authorities must follow when imposing fines. Sanctions should be applied without prejudice to the civil, criminal, or administrative liability that results from the application of sanctions by other legal systems and, where appropriate, from the revocation of the assignment, permit, or authorization, or the termination of the contract.

According to Article 25 of the AESA Law, 2014 (see footnote 400), ASEA can suspend or revoke licenses, authorizations, permits, or registrations in case of repeat or serious violations or nonpayment of financial penalties. However, ASEA reportedly favors a ‘corrective enforcement’ scheme under which operators can find a solution to achieve the required reduction.

G. Enabling Framework

20. Performance Requirements

Article 4 of the CNH Technical Provisions for the Use of Associated Natural Gas in the Exploration and Production of Hydrocarbons (see footnote 389) requires operators to conserve associated natural gas and sets technical standards. SEMARNAT and ASEA have technical and environmental standards regarding emissions from oil and gas operations. Articles 71–85 of the AESA Guidelines for the Prevention and Comprehensive Control of Methane Emissions from the Hydrocarbons Sector cover emissions control measures, such as requirements regarding fugitive emission detection systems and equipment, including the following:

• quarterly comprehensive leak-detection-and-repair programs
• replacement or installation of zero-emitting venting equipment
• prioritization of capture technologies over flaring to reduce emissions from tanks and other equipment
• standards for monitoring and reporting.

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal and other incentives for emission reductions could be found in the sources consulted. In fact, there is a disincentive to capture associated gas, because the value of associated gas calculated for royalty purposes is higher than the value of nonassociated gas until the contractual price of natural gas reaches a certain level. The formulas for calculating the value of associated and nonassociated gas can be found in Article 24 of the Hydrocarbon Income Law, 2014, which sets $5.5 per m3bd as the natural gas price above which associated and nonassociated gas obtain the same royalty rates.

22. Use of Market-Based Principles

Mexico is working on an Emissions Trading System (Sistema de Comercio de Emisiones) Test Program.417 In 2018, an amendment to the General Law on Climate Change (under SEMARNAT) established an emissions trading system that promotes emission reductions at the lowest possible cost. A three-year trial program began January 1, 2020. Operators of the installations associated with the development, production, transportation, and distribution of hydrocarbons can participate in the trading scheme. Only operators of those facilities with annual emissions of 100,000 tCO2 or more can participate in the trial program.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

The Pemex Law, 2008,418 created a new legal framework for the national oil company. At the same time, responsibility for upstream regulation was shifted to the CNH, and the functions of SENER and the Energy Regulatory Commission were strengthened. In 2013, amendments to Articles 25, 27, and 28 of the Constitution, 1917–20 were adopted. They allowed for the participation of private firms in activities previously reserved for the state. In 2014, additional transitory articles were signed into law outlining the main aspects of the secondary legislation needed to implement the different sector legislative changes. The 2014 secondary legislation created two bodies—the National Center for Control of Natural Gas (Centro Nacional de Control del Gas Natural) and National Energy Control Center (Centro Nacional de Control de Energía)—to operate, monitor, manage, and coordinate the gas and electricity networks. The National Center for Control of Natural Gas was tasked with managing the old Pemex gas pipeline network. Pemex withdrew from natural gas transportation, and private investors carried out a rapid expansion of the gas pipeline network. The pipeline transport capacity was tendered to interested shippers bidding through the open season process, and open access to the natural gas network was established. Interconnections with the US pipeline system were strengthened.
### Nigeria

6.63 billion cubic meters of gas flared in 2021  
(total oil production 1,547 thousand barrels per day)

#### Change in Flare Gas Volumes*

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<th>Year Pair</th>
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<td>Change</td>
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#### Change in Flare Gas Intensity**

<table>
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<th>2015-2020</th>
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</thead>
<tbody>
<tr>
<td>Change</td>
<td>22%</td>
<td>15%</td>
</tr>
</tbody>
</table>

* Annual volumes in billion cubic meters  
** Cubic meters of gas flared per barrel of oil produced

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### A. Policy and Targets

#### 1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Nigeria’s oil production fell by nearly 40 percent from 2012 to 2021. During this period, the flaring intensity barely changed. The volume of gas flared declined broadly in proportion to oil production, falling 25 percent, from 9.6 bcm to 6.6 bcm (figure 15). There were 166 individual flare sites in the last flare count, conducted in 2019.

In June 2016, Nigeria endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 3). It also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 30). Nigeria submitted its first NDC to the UNFCCC in 2015. It included gas flaring reduction as a mitigation measure, it submitted an updated NDC in July 2021. The update does not include unconditional contributions pertaining to the energy sector. Among the sector’s conditional contributions are zero routine flaring by 2030 and a 60 percent reduction in fugitive methane emissions by 2031.

Early oil and gas legislation—such as the Petroleum Act, 1969, and the Associated Gas Re-injection Act, 1979—included the prevention of atmospheric pollution and the conservation of resources. The Associated Gas Re-injection Act, 1979, prohibited gas flaring without the written permission of the minister in charge of oil and gas after January 1, 1984. However, measures to reduce flaring gained only limited traction, and the deadlines for ending routine flaring were repeatedly postponed.

In December 2017, the Ministry of Petroleum Resources published the National Gas Policy in the official gazette. The policy commits the government to taking measures to ensure the development of flare capture and utilization projects and to work collaboratively with the industry, development partners, providers of flare-capture technologies, and third-party investors. The policy also points out that the gas flaring penalty (at the time equivalent to US$0.03/thousand standard cubic feet [mscf]) was too low to act as a disincentive (making it more economic to flare than to pay the penalty) and needed to be raised substantially. The Annual Oil and Gas Industry Reports published by the Nigeria Extractive Industries Transparency Initiative (NEITI) show that, at even this very low penalty rate, some producers have not paid flaring penalties in full or at all.425

In 2016, the government launched the Nigeria Gas Flare Commercialization Program (NGFCP),424 targeting 2020 as the year by which routine flaring would be ended. This target was not met. In 2018, the government issued the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018,425 followed by four sets of associated guidelines.426 An important feature of the 2018 regulations was a marked increase in the flare payment rate.427 The 2018 regulations also provided a mechanism, similar to the one in Indonesia, for the government to take natural gas that would otherwise be flared and bid it out to third parties to commercialize it.

In August 2021, President Buhari signed the Petroleum Industry Act, 2021 (Petroleum Industry Act hereafter),428 an omnibus act covering the entire oil and gas value chain. Although it repealed some previous laws, such as the Associated Gas Rejection Act, 1979, the Petroleum Industry Act considers most other laws and regulations equivalent to having been issued by the new regulators as long as they provisions are not inconsistent and until such a time as amendments to the new law repeals them. In particular, it retains Petroleum Act, 1969, and several other laws until all licenses and leases signed under them are terminated. The Petroleum Industry Act contains five articles on gas flaring, promoting mimicking...
of flaring and reinforcing the basic principles in the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018.

2. Targets and Limits


B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Petroleum Act, 1969 (see footnote 422) granted to the minister in charge of oil and gas the exclusive power to issue regulations, including regulations supporting the conservation of petroleum resources and the prevention of atmospheric pollution. The Petroleum Industry Act (see footnote 428) narrows the powers of the minister and transfers some previously held powers to the newly established Nigerian Upstream Regulatory Commission (the Commission hereafter) and Nigerian Midstream and Downstream Regulatory Authority (the Authority hereafter). Section 105 authorizes the Commission to take gas destined for associated gas for their own purposes, but any gas—associated or non-associated—that will be monetized is owned by a newly restructured national oil company, the Nigerian National Petroleum Company Limited (NNPC Ltd). Previously, only gas produced under already signed PSCs belonged to the Nigerian National Petroleum Corporation (NNPC), predecessor to the NNPC Ltd.

5. Associated Gas Ownership

Associated gas is owned by producing companies, except in fields governed by PSCs and technical service contracts. The Petroleum Industry Act (see footnote 428) assigns ownership of associated gas not used or commercialized by licensees to the Commission, which auctions the gas. Following a bidding process, selected bidders can assume the associated gas ownership (without royalty obligations) and commercialization rights. PSC contractors are entitled to use associated gas for their own purposes, but any gas—associated or non-associated—that will be monetized is owned by a newly restructured national oil company.

6. Regulatory Authority

The Petroleum Industry Act assigns significant regulatory powers to the Commission and the Authority. The Commission has regulatory authority over gas flaring and venting in upstream oil and gas production; the Authority regulates the commercialization of previously flared gas. The Federal Environmental Protection Agency regulates air quality and other environmental emissions, including in the oil and gas industry. The Federal Environmental Protection Agency Act, 1988, empowers the agency to inspect, search, seize, and arrest in its areas of implementation of environmental policies, laws, and regulations; ensuring minimization of waste and optimization of government revenues; setting and enforcing standards and regulations; issuing permits and other authorizations; and conducting all licensing rounds. Previously, many of these responsibilities belonged to the minister under the Petroleum Act, 1969 (see footnote 422).

8. Monitoring and Enforcement

The Petroleum Industry Act (see footnote 428) grants nearly all monitoring and enforcement powers to the Commission and the Authority. The Minister of Petroleum revokes or suspends licenses upon the recommendation of the either of the regulators.

9. Flaring or Venting without Prior Approval

No evidence regarding flaring or venting without prior approval could be found in the sources consulted.

10. Authorized Flaring or Venting

No regulations have yet been issued to support Section 107 of the Petroleum Industry Act, which provides for permits for flaring or venting for a specific period if either is required to start up a facility or for strategic operational reasons. There is no reference to venting, except in greenfield developments, where it is forbidden (along with routine flaring) in Section 12 of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018 (see footnote 425).

11. Development Plans

Section 108 of the Petroleum Industry Act requires all licenses and leases to submit a natural gas flare elimination and monetization plan to the Commission prepared in accordance with (yet-to-
be-issued) regulations by the Commission. The clause suggests that development plans in the will need to include measures to eliminate routine flaring and venting.

12. Economic Evaluation
Paragraph 43 of the Petroleum (Drilling and Production) Regulations, 1969 (see footnote 422) requires the producer to submit a feasibility study, program, or proposals for the utilisation of natural gas no later than five years after the commencement of production. However, the Petroleum Industry Act grants the ownership of all gas produced in PSAs to the restructured national oil company NNPC Ltd, which also signs all future PSAs representing the Federation. As such, there will be no economic evaluation of gas monetization by any PSC contractors.

E. Measurement and Reporting
13. Measurement and Reporting Requirements
Part IV of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018 (see footnote 425) contains measurement and reporting requirements, including procedures, that are further detailed in the Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations431 issued by the previous regulator, the Department of Petroleum Resources (DPR). Section 21 of the 2018 regulations lev a substantial unit payment for noncompliance with any of the requirements imposed on oil producers with respect to currently flared associated gas.

14. Measurement Frequency and Methods
The Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, require daily log-keeping of all associated gas for flaring and venting and annual reporting of flare gas volumes. Section 3 of the Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations spell out data measurement, accounting, and reporting requirements. They include 13 subsections and many detailed technical specifications.

15. Engineering Estimates
Section 3.9 of the Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations provides for computation procedures during the transition period before the required meters are fully installed. The same procedures are to be followed in the event that one or more meters are unavailable or not functioning properly.

16. Record Keeping
Section 15 of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, calls for maintenance of daily logs of metered volumes of flared and vented gas, the format and manner of which are specified by the DPR. The logs must be submitted to the DPR—the Commission as soon as it becomes operational—within 21 days of the end of the reporting period. The producer is to keep them for at least 36 months.

17. Data Compilation and Publishing
Section 19 of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, requires the DPR to collect gas flaring data and publish them in its annual reports, which are posted on the agency’s external website with a time lag.432 In addition, NEITI collects data and publishes them in its annual Oil and Gas Industry Reports (see footnote 423). As of October 2021, the DPR’s website had posted reports covering flaring data from 2001 to 2018 but no information on the penalties paid. NEITI’s Oil and Gas Industry Reports from 1999 to 2019 contain flaring data and penalties paid by individual companies.

In January 2020, the NNPC created a new web page entitled EITI Support Open Data.433 which includes data on gas utilisation, re-injection, and flaring from operations with NNPC participation; there are no data from operations that do not include NNPC participation. The data, in spreadsheet format, are uploaded on the NNPC’s external website with a time lag as short as a month. Separately, in August 2015, the NNPC began publishing its monthly financial and operational performance reports,434 covering data going back to January 2015 for gas flared in operations with NNPC participation. As of September 2021, the most recent data published on the EITI Support Open Data website were from July 2021.

F. Fines, Penalties, and Sanctions
18. Monetary Penalties
Section 21 of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018 (see footnote 425) imposes a payment of US$2.50 per mscf for all gas flared or vented in noncompliance with any of seven specified requirements in the regulations, including those for reporting, granting site access to the regulator, and using metering equipment. Repeat offenders risk license revocation. Section 21 describes the current flare payments.

19. Nonmonetary Penalties
Under Section 3 of the Petroleum Industry Act (see footnote 428), the minister of petroleum can revoke or suspend petroleum licenses and leases for noncompliance, upon the recommendation of the Commission. Section 217 states that any dispute between a licensee or a lessee and the Commission is to be settled by the Federal High Court. Sections 21 and 22 of Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, allow suspension or revocation of the license in the event of continued noncompliance with seven listed requirements. No evidence of license revocation because of flaring-related offenses has been made public.

G. Enabling Framework
20. Performance Requirements
No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives
Section 13 of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, imposes a flare gas payment of US$2.00 per mscf in a license area or field producing 10,000 barrels a day of oil or more and US$0.50 per mscf in areas producing less. The fees apply to all associated gas flared, whether routine nonroutine and whether the producer has the right to commercialize the gas or not. Even before the enactment of the Petroleum Industry Act, no PSC contractor had been permitted to monetize gas, although such authorization was in principle possible by asking the government to issue a supplementary agreement, an agreement closed by the 2021 law. There are, however, two exceptions to this otherwise universal payment:

• war, community disturbance, insurrection, or a natural disaster beyond the control of the oil producer
• the signing by the oil producer of a deliver-or-pay agreement with a third party that has been granted a permit to access gas in an auction conducted by the federal government.

Payments are to be made within a month of the end of each quarter. NEITI has been tracking the payment record. According to the Oil and Gas Industry Audit Report 2019 published by NEITI (see footnote 423), US$308 million was paid in 2019, up from US$15 million in 2018. The DPR began issuing invoices for the new flare payments only in 2019. The huge increase that year illustrates the impact of the substantial increase in the flare payment rates. At the time of writing, the DPR had not yet published data on flare payments.

Paragraph 11 of the Petroleum Profits Tax Act, 1958 (see footnote 422) provides incentives for gas separation and treatment investments by making such investments deductible against revenue. The incentives were extended to nonassociated gas in 1999, and therefore they are no longer specific to associated gas. The Petroleum Industry Act (see footnote 428) repeals the Petroleum Profits Tax Act, 1958, for new acreages. Section 39 of the Companies Income Tax Act, 1990,435 provides large fiscal incentives for gas utilisation. The section offers the following benefits:
Nigeria

• an initial tax-free period of three years, renewable for an additional two years, or an additional investment allowance of 35 percent
• accelerated capital allowance of 90 percent a year after the tax-free period and an additional capital allowance of 15 percent without reducing the asset value
• tax-free dividends during the tax-free period if the investment is in a foreign currency and imports are not less than 30 percent of the company’s equity share capital
• the deductibility of loan interest payments, provided the minister of petroleum resources approved the loans.

These incentives do not apply to gas produced in fields governed by PSCs.

22. Use of Market-Based Principles

The Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, provides for auctions organized by the government in which third parties can bid for gas currently being flared. The NGFCP announced the first auction in November 2018. It announced the applicants deemed qualified in mid-2019, and the bidding round was closed at the end of June 2020. At the time of writing, the outcome of the first auction had not been announced.

As mentioned in section 12, the Petroleum Industry Act grants the ownership of all gas produced in PSCs to the NNPC Ltd, depriving the contractors of the right and ability to commercialize associated gas and reduce flaring. Restricting the right to commercialize any gas to one entity stifles competition and limits the leveraging of market principles and forces to facilitate flaring and venting reduction.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

The Companies Income Tax Act, 1990, provides incentives for the utilization of associated and non-associated natural gas. Gas utilization is defined as the marketing and distribution of natural gas for commercial purposes and includes power generation, LNG, gas-to-liquid plants, fertilizer production, and gas transmission and distribution pipelines. Nigeria also adopted a gas transportation network code in 2020, formalizing third-party access to critical gas infrastructure.
Norway

0.15 billion cubic meters of gas flared in 2021
(total oil production 1,766 thousand barrels per day)

<table>
<thead>
<tr>
<th>Change in Flare Gas Volumes*</th>
<th>2015-2021</th>
<th>2015-2020</th>
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<tbody>
<tr>
<td><strong>-54%</strong></td>
<td><strong>-63%</strong></td>
<td></td>
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<tr>
<th>Change in Flare Gas Intensity**</th>
<th>2015-2021</th>
<th>2015-2020</th>
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<tbody>
<tr>
<td><strong>-58%</strong></td>
<td><strong>-65%</strong></td>
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* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 16 Gas flaring volume and intensity in Norway, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Norway has Europe’s largest hydrocarbon reserves and is the world’s fifth-largest exporter of crude oil. It recorded the lowest flaring intensity of all countries under review every year between 2012 and 2021. Norway produced about the same amount of oil in 2021 as Kazakhstan, and Mexico, but these countries flared 10–43 times the volume flared in Norway. Between 2012 and 2021, oil production rose slightly in Norway, but both the volume of gas flared and the flaring intensity declined by three-fifths (figure 16). There were just 28 individual flare sites in the last flare count, conducted in 2019.

In Equinor ASA (a Norwegian majority state-owned energy company) endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2015 (World Bank, n.d.; see footnote 3), followed by the endorsement by the government of Norway in 2016. Norway also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 30).

Norway submitted its first NDC to the UNFCCC in June 2016 and its update in February 2020. 439 The update increased the target for reducing economy-wide GHG emissions from the 1990 level of 40 percent to 50–55 percent by 2030.

Environmental and climate considerations are an integral part of Norway’s petroleum industry policies. The Norwegian petroleum industry has higher local and global environmental standards than most other oil- and gas-producing countries. Norway has imposed restrictions on flaring and venting since oil production began in the early 1970s. In 1971, the government adopted the so-called 10 Oil Commandment principles for oil-related policies (Meland 2022). 440

The fifth commandment prohibits gas flaring on the Norwegian continental shelf except during brief periods of testing and for safety-related reasons. 441

The government’s Environmental Policy and the State of the Environment, 2000–2001 442 prohibited gas flaring and venting to avoid wasting energy. Operators are required to have a solution in place for the gas, and the Norwegian authorities must approve any flaring and venting for operational safety. Norwegian environmental policy has historically been based on direct regulation of environmentally harmful emissions and discharges. The CO₂ Tax Act, or Act No. 72 Relating to Tax on the Discharge of CO₂ in the Petroleum Activities on the Continental Shelf. 1990 (the CO₂ Tax Act, 1990 hereafter) 443 and the emissions cap system have had a significant impact on reducing emissions. Norway aims to reduce GHG emissions to near zero by 2050, as outlined in Equinor’s 2020 Sustainability Report 444 and the Act Relating to Norway’s Climate Targets, 2018 (the Climate Change Act, 2018 hereafter). 445

2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Act No. 72 Relating to Petroleum Activities, 1996 446 or the Norwegian Petroleum Act. 1996, prohibits gas flaring in excess of the quantities needed for operational safety unless approved by the Norwegian Petroleum Directorate (NPD). 447 The Regulations to Act Relating to Petroleum Activities, 1996 448 provide further details on the permit application process and the reporting of flare and vent

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447 Norwegian Petroleum Directorate (NPD). 447 The Regulations to Act Relating to Petroleum Activities, 1996 448 provide further details on the permit application process and the reporting of flare and vent...
volumes (see sections 10 and 13 of this chapter). The Measurement Regulations, or the Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO₂ tax, 2005, detail how to measure and report flare and gas volumes. The NPD publishes guidelines to help with the compliance of these regulations. They cover the following:

- application for a production permit, including a flaring permit
- fiscal measurement of oil and gas
- plan for development and operations of petroleum activities
- standards relating to the measurement of petroleum.

Section 2 of the CO₂ Tax Act, 1990 (see footnote 443) imposes a CO₂ tax on flared or vented gas and CO₂ separated from petroleum, and discharged into the air at installations used to produce or discharge waste. The Pollution Control Act, 1981454 (the Pollution Control Act, 1981) is intended to protect the quantity of waste, and promote better waste management. It aims to ensure that pollution and waste do not damage human health or affect the welfare of, or damage, the natural environment’s productivity and self-renewal capacity.

4. Legislative Jurisdictions

Flaring and venting are matters of national jurisdiction, per Section 1 of the Norwegian Petroleum Act, 1996 (see footnote 446).

5. Associated Gas Ownership

Section 3 of the Norwegian Petroleum Act, 1996, states that the licensee owns all oil that is produced. As a result, the licensee owns all gas that is flared or vented. This ownership allocation is consistent with the CO₂ Tax Act, 1990, Section 4 of which requires the licensee to pay the CO₂ tax.

6. Regulatory Governance and Organization

6. Regulatory Authority

The NPD under the Ministry of Petroleum Energy (MPE) is the key institution in charge of policy, regulation, and enforcement of gas flaring and venting.455 The Norwegian Ministry of Climate and Environment456 develops integrated climate and environmental policies. Its subordinated agency, the Norwegian Environment Agency,457 is the environmental regulator.

7. Regulatory Mandates and Responsibilities

The NPD is responsible for general resource management considerations, including reducing emissions from oil and gas activities to the air and the sea through cost-effective measures. It monitors and collects data on the volumes of gas flared, as outlined in the Regulations Relating to Resource Management in the Petroleum Activities, 2018.458 The Norwegian Environment Agency is responsible for implementing the Pollution Control Act, 1981 (see footnote 454). The Norwegian Environment Agency’s overall responsibilities cover managing Norway’s natural assets and preventing pollution. These responsibilities also entail areas relevant to flaring and venting, such as the promotion of clean air and a toxic-free environment and the reduction of noise pollution.

8. Monitoring and Enforcement

Section 38 of the Regulations to Act Relating to Petroleum Activities, 1997 (see footnote 448) authorizes representatives from the MPE, the NPD, or other authorities as decided by the NPD to access vessels and facilities for inspection of petroleum activities. They may also access all existing data and materials necessary to perform regulatory supervision, and they have the right to participate in survey activities. Representatives from the authorities have the right to stay on vessels and facilities for as long as necessary.

9. Flaring or Venting without Prior Approval

Section 9 of the Norwegian Petroleum Act, 1996 (see footnote 446) requires oil and gas operations to be conducted in such a manner as to maintain a high level of safety. Section 4 of the law allows operators to flare associated gas in the quantities needed for operational safety. No specific details related to when the venting of associated gas would be allowed without regulatory approval could be identified in the sources consulted.

10. Authorized Flaring or Venting

Section 23 of the Regulations to Act Relating to Petroleum Activities, 1997,459 requires the operator to apply to the MPE to flare or vent gas, with a copy of the application submitted to the NPD. Upon application, the MPE specifies the quantity that may be produced, injected, or vented for fixed periods according to Section 4 of the Norwegian Petroleum Act, 1996. The NPD ensures compliance with these quantities. Venting is usually allowed for safety reasons, start-up, or testing.

11. Development Plans

Section 4 of the Norwegian Petroleum Act, 1996, requires the submission of a field development plan to the MPE for approval. The plan should cover all dimensions, including economic, reservoir, technical, safety, and environmental and decommissioning aspects. These requirements are detailed in Section 21 of the supporting regulations, Regulations to Act Relating to Petroleum Activities, 1997 (see footnote 448). The plan for development and operation should include a description of technical solutions and cover means of preventing and minimizing environmentally harmful discharges and emissions, such as flaring and venting. The development plan should also include information on approvals or consents that have been applied for, including flaring and venting authorizations.

12. Economic Evaluation

Section 4 of the Norwegian Petroleum Act, 1996, requires oil and gas to be produced according to prudent technical and sound economic principles and avoid wasting petroleum resources. Toward that end, the licensee should continuously evaluate the production strategy and technical approach being used and take the necessary measures accordingly. Facts 2012–2013 of the Norwegian Petroleum Sector, 2012,460 illustrates several projects implementing opportunities to minimize gas flaring and venting. An example is the Goliat Project, an oil and gas field located in the Barents Sea. The discovery well was drilled in 2000, and the field went into production in 2016. Associated gas has been re-injected or transported through a pipeline to Melkøya.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Section 48 of the Regulations to Act Relating to Petroleum Activities, 1997 (see footnote 448) requires the operator to submit information to the NPD on the use, injection, flaring, and venting of natural gas. Such information should be based on metering as much as possible. The Measurement Regulations, 2001 (see footnote 449) stipulate functional and compliance requirements, including reporting and documentation, related to the planning, design, construction, and operation of metering systems and equipment to measure and report the quantities of gas flared or vented in petroleum activities. The NPD approves the equipment and procedures. Section 29 of the Measurement Regulations, 2001, requires the reporting of CO₂ tax metering for the calculation of payment of the CO₂ tax every six months (calculated per field or facility).
Norway

Section 3 of the Comments to Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO₂ Tax, 2018, holds the operator of the individual field or facility directly responsible for the duties placed with the licensees jointly pursuant to the Norwegian Petroleum Act, 1996 (see footnote 446) and the CO₂ Tax Act, 1990 (see footnote 443) such as the design, purchase, and operation of metering systems with associated reporting and payment of tax. The CO₂ Tax Act, 1990, authorizes the Ministry of Finance to issue additional provisions for the CO₂ tax and equipment requirements for metering, measurement methods, and documentation.

14. Measurement Frequency and Methods

Operating companies that hold flaring permits must submit a report to the MPE indicating the amount of gas flared daily. Section 8 of the Measurement Regulations, 2001 sets the uncertainty limit at 5 percent by volume for flared or vented gas and lists uncertainty and repeatability limits for different types of measuring instruments. According to Section 11, gas composition is determined from continuous flow proportional gas chromatography or from automatic flow proportional sampling.

15. Engineering Estimates

Section 29 of the Measurement Regulations, 2001 requires documentation of engineering estimates in lieu of measurement where measurement was not carried out for technical reasons.

16. Record Keeping

Operators are responsible for keeping an emissions inventory, which they are required to submit to the NPD annually. According to Chapter 4 of Act No. 99 Relating to Greenhouse Gas Emission Allowance Trading and the Duty to Surrender Emission Allowances, 2004, operators must submit a report on GHG emissions to the pollution control authorities in a given calendar year by March 1 of the following year. No information could be found in the sources consulted regarding how long records are to be kept.

17. Data Compilation and Publishing

Emissions from the oil and gas sector in Norway are well documented. The MPE publishes data on its website. The Norwegian Oil and Gas Association, an industry organization, has established a national database for reporting all releases from the industry, called the EPM Environment Hub. All operators report data on emissions to air and discharges to the sea directly in the EPM Environmental Hub. The data are published annually in the Resource Report Discoveries and Fields. Statistics Norway publishes statistics on air pollution from activities, including oil and gas extraction.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

According to Section 10 of the Norwegian Petroleum Act, 1996 (see footnote 446), noncompliance with an order issued pursuant to the law may result in a daily fine for each day of the violation. Section 10 subjects a willful or negligent violation to fines or imprisonment. As the Norwegian Petroleum Act, 1996, prohibits flaring in excess of what is needed for safe operations, these fines apply to such excessive flaring. Separately, a carbon tax is imposed on all gas flared or vented, and willful or negligent submission of incorrect or incomplete documentation or any other breach of provisions or decisions contained in or issued by virtue of the CO₂ Tax Act, 1990 (see footnote 443) is subject to a fine.

19. Nonmonetary Penalties

Section 10 of the Norwegian Petroleum Act, 1996, imposes nonmonetary penalties, including the temporary suspension of activities, license revocation, and imprisonment of as long as two years for a willful or negligent violation. Willful or negligent submission of incorrect or incomplete documentation or any other breach of provisions or decisions contained in or issued by virtue of the CO₂ Tax Act, 1990 may result in imprisonment of up to three months.

G. Enabling Framework

20. Performance Requirements

No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives

The main instruments for restricting GHG emissions are economic—emissions trading and the CO₂ tax; they provide financial incentives to minimize emissions. Norway was one of the first countries in the world to introduce a carbon tax, in 1990. Sections 1, 2, and 4 of the CO₂ Tax Act, 1990 (see footnote 443) require a CO₂ tax payment for flared or vented natural gas and any other CO₂ discharged to the atmosphere during the production and transportation of oil and gas unless otherwise exempted by the Storting (parliament). The operator calculates, reports, and pays the total tax amount to the NPD on behalf of all other licensees. The operator provides the NPD with the documentation for metering petroleum and calculating the tax within a month of the expiry of each term. If the tax is not paid on time, it accrues interest. According to Section 3 of the CO₂ Tax Act, 1990, the CO₂ tax is not deductible from the calculation of the production fee (defined in Section 4 of the Norwegian Petroleum Act, 1996; see footnote 446).

For 2021, the tax rate is proposed at NOH 1.27 (about US$0.1 as of September 2021) per m³ of gas or per liter of oil and condensate. For emissions of natural gas, the tax rate is NOH 8.76 (about US$1 as of September 2021) per m³. For combustion of natural gas, the rate is equivalent to NOH 5.43 (about US$0.64 as of September 2021) per tCO₂e. Together with the EU ETS allowance costs, oil and gas companies operating in the Norwegian offshore pay about NOH 800 (about US$94 as of September 2021) per tCO₂e. The Norwegian government proposes to gradually raise the total cost of carbon (Norwegian CO₂ tax and the cost of EU ETS allowance) to NOH 2,000 (about US$240 as of September 2021) per tCO₂e by 2030.

22. Use of Market-Based Principles


23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

Section 59 of the Regulations to Act Relating to Petroleum Activities, 1997 (see footnote 448) grants operators undertaking downstream natural gas activities and eligible customers the right to access pipeline networks. The access is subject to the quality of the gas being compatible with technical specifications or efficient operation of the pipeline network. The pipeline network operator may require additional conditions after consulting with existing users of the pipeline network.

Oman

2.48 billion cubic meters of gas flared in 2021 (total oil production 970 thousand barrels per day)

<table>
<thead>
<tr>
<th>2015-2021</th>
<th>2015-2020</th>
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<tr>
<td><strong>2%</strong></td>
<td><strong>3%</strong></td>
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* Annual volumes in billion cubic meters

**Cubic meters of gas flared per barrel of oil produced**

A. Policy and Targets

1. **Background and the Role of Reductions in Meeting Environmental and Economic Objectives**

Between 2012 and 2021, oil production in Oman was fairly stable, varying by no more than 5 percent from the mean. The flaring intensity, however, rose by 11 percent, and the volume of flared gas increased by one-fifth (Figure 17). There were 106 individual flare sites in the last flare count, conducted in 2019.

In 2016, Oman endorsed the World Bank’s Zero Routine Flaring by 2030 initiative (World Bank, n.d.; see footnote 471). It commits the government to an unconditional contribution of a 3 percent reduction in the growth of GHG emissions by 2030 and a conditional contribution of an additional 4 percent reduction, for a total of 7 percent. The upstream oil and gas sector targets zero emissions by 2050. One instrument for implementing this target is the 2016 endorsement of the Zero Routine Flaring initiative.

The second NDC also outlines measures that will reduce the GHG intensity of upstream oil and gas operations: electrification of equipment, reliance on renewable energy for electricity, efficiency improvement in existing facilities, and a significant reduction in gas flaring as well as methane and other fugitive emissions. Operators in Oman have used the CDM of the UNFCCC for two associated gas-recovery projects.

The PDO is responsible for producing about 70 percent of oil and gas in Oman. Since joining the initiative, the Ministry of Energy and Minerals, and the Environment Authority was created to replace the Ministry of Environment and Climate Affairs. The Financial Affairs and Energy Resources Council, which used to set domestic oil and gas prices, was abolished. Apart from these decrees, there were parallel changes in the energy sector. At the end of 2019, a new national petroleum investment company, QO, was formed by merging nine companies across the energy sector. At the end of 2020, a new government company, Energy Development Oman, was established. This holding company of the PDO will focus on natural gas, renewable energy, and green hydrogen. **Flare gas management remains a priority for both the PDO and Energy Development Oman**.

2. **Targets and Limits**

There are no targets or limits on the volumes of natural gas flared or vented. However, regulations are under development, which are expected to include targets (see footnote 471).

B. **Legal/Regulatory Framework and Contractual Rights**

3. **Primary and Secondary Legislation and Regulation**

Articles 39 and 40 of Royal Decree No. 8/2001, known as the Oil and Gas Law, set out environmental protection principles. According to Article 39, operators should not dispose of gas unless necessary, and when necessary, they should use appropriate means to protect the environment. Article 39 also requires operators to reduce GHG emissions by using appropriate technology. Article 40 requires the use of international best practices, standards, and specifications. Article 18 requires that concessionaires and their subcontractors comply with the terms of the concession agreement and all permits and approvals issued by the MEM or other government authorities, as well as with other laws, rules, and regulations in Oman.

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Oman

Exploration and production-sharing agreements include health, safety, and environmental clauses that reflect existing laws and current energy and environment policies. For example, exploration and production-sharing agreements ban flaring without a permit except during well testing. Ministerial Decree No. 114/2004, known as the Well Test Regulatory Protocol, specifies the requirements for operators to obtain a permit. Ministerial Decision No. 118/2004, entitled the Regulations for the requirements for operators to obtain a permit. 114/2012, known as the Well Test Regulatory Protocol, specifies include various environmental requirements (see footnote 475).

Without obtaining a permit from the Ministry. " Article 27 requires be handled, dealt with or disposed of in the Omani environment for optimum exploitation" of natural resources, including oil and gas. Article 3 of the Oil and Gas Law (see footnote 474), regulates flaring and venting. It negotiates exploration and production-sharing agreements with investor companies. All agreements are based on a template, but negotiations can lead to additional clauses and modifications, including flaring and venting restrictions. The Environmental Authority regulates environmental impacts, including from oil and gas operations. 476

7. Regulatory Mandates and Responsibilities

The MEM is responsible for reviewing and approving gas conservation plans and their annual updates. The plans include the total annual volume of gas disposed of by flaring and venting. The Environmental Authority is responsible for issuing and ensuring compliance with environmental permits for flaring emissions. 477

8. Monitoring and Enforcement

Article 23 of the Oil and Gas Law (see footnote 474) states that concession holders must allow MGM officials to inspect facilities, equipment, and extracted petroleum materials and review and copy operational records. Article 3 of the Law on Conservation of the Environment and Prevention of Pollution (see footnote 478) requires an environmental permit for emissions, including from flaring in oil and gas fields and refineries, before construction or operation. Article 11 permits operators to provide a plan if requested by inspectors. 479

9. Flaring or Venting Without Prior Approval

Since 2017, Oman has reportedly been considering developing flaring and venting guidelines consistent with widely accepted international practices. Alignment with international practice would suggest that flaring or venting without approval would be allowed during emergencies but immediately followed by reporting to the regulator of flaring or venting details (see footnote 479).

10. Authorized Flaring or Venting

International practices, which Oman’s new flaring and venting guidelines are expected to follow, typically ban all routine flaring but allow exceptions for flaring during well testing (permitted within limits) and for volumes approved in the gas conservation plan (see footnote 479).

11. Development Plans

Alignment with international practices would suggest that gas conservation plans have to consider all reasonable utilisation options before flaring and venting and that the MEM ensures compliance with the gas conservation plan during the development and operation of assets (see footnote 479).

12. Economic Evaluation

Oman’s new flaring and venting guidelines are expected to follow international practices and build on the PDO’s practice of conducting an economic evaluation of flaring and venting projects. Since 2018, the PDO has been managing all nonroutine flaring activities using the concept of measures that are as low as reasonably practical. The PDO has developed an electronic system, Flaring waiver and As Low as Reasonably Practicable Demonstration Tool, to conduct an economic and environmental evaluation of each nonroutine flaring scenario. 480 The PDO has tested a micro-turbine to convert flared gas into electricity at Angau. If replicated across Block 6, about 500,000 m³ of gas currently flared a day could be recovered. The PDO’s Gas Directorate, through its energy management efforts, saved 46,000 m³ of natural gas a day that was previously flared or used as a fuel, in 2019. 481

At the end of 2018, the PDO issued a request for bids from companies with proven gas-to-power technology and experience using gas being flared. 481 In early 2021, Japan’s Sumimoto Corporation and an independent Oman company, ARA Petroleum, initiated a feasibility study on a project to produce hydrogen from associated gas from ARA’s oil field that would otherwise be flared. In addition, a 20-MW solar farm will provide electricity to a methane steam reformer for hydrogen production. Oman has been trying to promote hydrogen, and several companies have expressed interest in pursuing hydrogen projects in special economic zones in Oman. 481

E. Measurement and Reporting

13. Measurement and Reporting Requirements

According to the Regulations for Air Pollution Control from Stationary Sources (see footnote 479), air emissions listed in the appendix are to be measured by instruments. Fugitive emissions can be estimated using mass balance equations. Flaring and venting guidelines under development since 2017 suggest that reporting will be required to ensure compliance with targets to be established (see footnote 479).
Oman

14. Measurement Frequency and Methods
In 2019, all PDO flare stacks were mapped to identify any unmonitored or unreported streams. The PDO also established a dashboard to make flaring data available and more visible across the company.466

15. Engineering Estimates
See section 13. No additional details on engineering estimates could be found in the sources consulted.

16. Record Keeping
No evidence regarding record-keeping requirements could be found in the sources consulted. However, the Oil and Gas Law (see footnote 474) and the Law on Conservation of the Environment and Prevention of Pollution (see footnote 478) empower the inspectors and the Law on Conservation of the Environment and Prevention of Pollution (see footnote 478) empower the inspectors to access records to ensure compliance with laws, regulations, and permits (see section 8 of this chapter).

17. Data Compilation and Publishing
No evidence regarding data compilation and publishing could be found in the sources consulted. However, the PDO reports flaring data from its operations in its annual Sustainability Reports. Two blocks operated by Occidental Oman use the CDM mechanism (see section 22 of this chapter). CDM monitoring reports include data on recovered volumes of associated gas that would otherwise have been flared or vented.

18. Fines, Penalties, and Sanctions
Chapter 8 of the Oil and Gas Law (see footnote 476) does not specify any penalties for violations of Article 39, which sets environmental requirements with respect to gas or violations of Articles 41–43, which outline provisions regarding gas use. However, Article 51 of Chapter 8 allows the minister of energy and minerals to determine penalties for violations of articles of the law not specified in the chapter.

Article 39 of the Law on Conservation of the Environment and Prevention of Pollution (see footnote 478) deals with monetary penalties for violating certain articles of the law, including the need to obtain a permit and the prohibition on emitting more than the limits in the permit. The fine is set at RO 200–RO 2,000 (about US$552–US$552 as of September 2021), with an increase of 10 percent a day starting four days after notification of the violation. Article 36 provides for a fine of up to RO 500 (about US$130 as of September 2021) if environmental inspectors are prevented from exercising their powers. Article 40 sets a fine of between RO 1,000 and RO 5,000 (about US$2,600–US$13,000 as of September 2021) in case of failure to comply with Article 27, which calls on operators to establish “controls for optimum exploitation” of natural resources, including oil and gas (see section 3 of this chapter). The penalty is doubled for a repeat violation.

19. Nonmonetary Penalties
According to Article 31 of the Law on Conservation of the Environment and Prevention of Pollution, the suspension of activity is possible if a violator does not correct the offense within a month. According to Article 32, the use of falsified data or statements to obtain an environmental permit is punishable by up to six months in prison, a fine of up to 5 percent of the invested capital, or both. The permit may even be canceled, in which case the activity must cease. Article 36 allows for prison time of up to three months if environmental inspectors are prevented from exercising their powers. This imprisonment can be in addition to a fine. The court may also shut down the facility for up to a month.

20. Performance Requirements
The PDO has followed the practice of minimizing routine flaring in new installations and the principle of reducing flaring and venting to as low a level as reasonably practicable. The Regulations on Air Pollution Control from Stationary Sources (see footnote 477) set limits on six pollutants that can be emitted from flaring in petroleum fields and refineries. They also state that any combustion cannot emit smoke darker than ‘shade 1 on the Ringemann Scale (20 percent opacity).’

21. Fiscal and Emission Reduction Incentives
Chapter 7 of the Oil and Gas Law (see footnote 474) provides several provisions with respect to natural gas. Article 41 requires the concessionaire to reserve natural gas and allows its exploitation, with MEM approval, to enhance oil recovery, store it underground, commercialize it, or use it for any other purposes as decided by the MEM. Article 42 provides for features, incentives and facilities to encourage gas exploitation to be stipulated in the concession agreement. For example, the concessionaire is allowed to recover gas discovery expenses if the MEM decides to postpone production to meet future domestic market demand.

22. Use of Market-Based Principles
Oman has two associated gas recovery and utilization projects under the CDM, both operated by Occidental Oman and hosted by the MEM, representing the government. The first project, at Block 9, was registered in December 2012.467 The recovery of associated gas that would otherwise have been flared or vented started in 2010. Over the crediting period (December 31, 2013–December 30, 2020), about 2.1 bcm of associated gas was recovered, with an average methane content of about 70 percent. The project had reduced emissions by about 2.1 million tCO₂e by the end of 2020. The second project, at the Kharmilah oil field area in Block 27, was registered in August 2020. Over the crediting period (August 3, 2020–August 2, 2030), about 2.3 bcm of associated gas is estimated to have been recovered, with an average methane content of about 78 percent. The project is expected to reduce emissions by about 0.43 million tCO₂e annually.

23. Negotiated Agreements between the Public and the Private Sector
The Minister of Energy and Minerals is also the chairman of the board of directors of the PDO. The board also includes other representatives from the MEM as well as representatives from the Ministry of Finance. The government’s stake in the PDO is 60 percent, with MEM representatives from the MEM and the Ministry of Commerce, Industry, and Investment Promotion (the Financial Affairs and Energy Resources Council), which includes representatives of the MEM and the Ministry of Finance. The government’s stake in the PDO is 60 percent, with MEM representatives from the MEM and the Ministry of Commerce, Industry, and Investment Promotion (the Financial Affairs and Energy Resources Council before August 2020). These prices, as well as the price of electricity (which is almost exclusively generated by gas-fired power plants), have been below cost. The government of Oman raised natural gas prices to industrial and power generation plants, involving the PDO are public–private partnerships, including efforts to reduce flaring (see section 12 of this chapter).

24. Interplay with Midstream and Downstream Regulatory Framework
Natural gas consumption has been increasing in Oman, primarily to generate electricity and run desalination plants but also for use in downstream refining and petrochemical facilities. Oman is a significant exporter of LNG, but it also imports pipeline gas from Qatar to balance domestic demand with export obligations. However, with increased investment in gas fields and, to a lesser extent, more aggressive policies toward capturing associated gas, Oman intends to phase out imports and expand domestic pipeline infrastructure.

Low domestic gas prices have presented a challenge to achieving the goal of supplying gas for domestic purposes from domestic sources. The MEM and the Oman Gas Company have supplied gas to industrial and power generation plants at prices set by a gas allocation committee, which includes representatives of the MEM and the Ministry of Commerce, Industry, and Investment Promotion (the Financial Affairs and Energy Resources Council before August 2020). These prices, as well as the price of electricity (which is almost exclusively generated by gas-fired power plants), have been below cost. The government of Oman raised natural gas prices to industrial and power generation plants, involving the PDO are public–private partnerships, including efforts to reduce flaring (see section 12 of this chapter).

The government issued the Public Private Partnership Law as Royal Decree No. 52/2019488 in 2019 and its implementing regulations in 2020. The law does not specify or restrict types of projects if they improve public services and align with Oman’s economic development strategy. The law was partially motivated to relieve pressure on the government’s budget. The same rationale also induced the creation of Energy Development Oman, in late 2020. The law offers another avenue for the efforts of the PDO and other companies to reduce flaring and meet Oman’s growing gas demand. The MEM, together with operators, may pursue the aggregation of associated gas from different locations to achieve the economies of scale needed to make utilization projects financially viable.
Oman

but low oil prices after 2016, especially in 2020, stressed the government’s budget and slowed further price reforms.

The Energy Development Oman was created as a company that could raise capital at a lower cost than the government and undertake major energy transition projects (see footnote 472). The Oman Gas Company, along with eight other state-owned companies across the oil and gas value chain, is now part of OQ, created in 2019. The newly integrated company is fully government-owned, but a partial public offering of shares is under consideration, as the government continues to focus on its budget deficit. The net effect of the changes cited in this section on domestic gas consumption, the development of new gas pipelines, and associated gas utilization will become apparent over the coming years.
Russian Federation

25.41 billion cubic meters of gas flared in 2021 (total oil production 10.110 thousand barrels per day)

Figure 18 Gas flaring volume and intensity in the Russian Federation, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The Russian Federation was the world’s largest contributor by volume to gas flaring in 2021 (figure 18). The traditional oil-producing regions of West and East Siberia, as well as the Khanty-Mansiysk Autonomous Okrug district, have been the key contributors. The flaring intensity has been increasing since 2017, reaching the highest level since 2012 in 2021. There were 1,086 individual flare sites in the last flare count, conducted in 2019.

Russia endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2016 (World Bank, n.d.; see footnote 3); two of its major national oil companies, Gazprom and Lukoil, did so in 2018. Russia also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 30).

Russia’s first NDC, submitted to the UNFCCC in November 2020, targets a reduction in GHG emissions to 70 percent of the 1990 level but does not mention gas flaring and venting.

Starting in 2007, with the President’s State of the Nation Address, increasing the efficient use of associated gas and reducing flaring became national priorities. One of the targets of the Energy Strategy for Russia for the Period Up to 2030 (Ministry of Energy of the Russian Federation 2001) is the utilization of 95 percent of associated gas. To help achieve it, Russia passed, key legislation, Article 1 of Federal Law No. 7-FZ on Environmental Protection, 2001, states that one of its overarching goals is to prevent adverse impacts on the natural environment from economic or other activities. Article 16 states that fees will be levied for the environmental factors (Appendix 2) to be used in the calculation formula for the fee. Federal Decree No. 2395-1 on Subsoil, 1992, is the central piece of primary and secondary legislation and Regulation

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Federal Law No. 2395-1 on Subsoil, 1992, is the central piece of legislation for the use of subsurface resources and related matters (Article 1). Article 23 requires rational use of subsurface resources.

Article 1 of Federal Law No. 7-FZ on Environmental Protection, 2001, states that one of its overarching goals is to prevent adverse impacts on the natural environment from economic or other activities. Article 16 states that fees will be levied for the emission of pollutants and specifies the procedures for calculating the fees for gas flaring and venting.

Federal Decree No. 1148, 2012, requires high emitters (those above 150,000 tCO₂ by 2023 and above 50,000 tCO₂ by 2024) to comply with carbon reporting requirements, which have not yet been fully defined. The stated purpose of this new legislation is to “create conditions for sustainable and balanced development of the economy.” As such, it is in line with the general trend toward debottlenecking of the oil and gas value chain.

2023-2024 requires high emitters [those above 150,000 tCO₂ by 2023 and above 50,000 tCO₂ by 2024] to comply with carbon reporting requirements, which have not yet been fully defined. The stated purpose of this new legislation is to “create conditions for sustainable and balanced development of the economy.” As such, it is in line with the general trend toward debottlenecking of the oil and gas value chain.

2. Targets and Limits

Federal Decree No. 1148, 2012, limits flaring or venting to 5 percent of the total volume of associated gas produced. This target was first mentioned in the Energy Strategy for Russia for the Period up to 2030 (approved by Federal Decree No. 1715-r, 2009).

496 http://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Russian_Federation_First/NDC_RF_eng.pdf (Accessed on August 24, 2021).
Russian Federation

payment process for these fees (Sections 1 and 4).

Articles 1 and 4 of Federal Law No. 69-FZ on Gas Supply, 1999, require the rational use of gas. They are intended to ensure that the country’s need for energy resources is met. Article 27, in combination with the amendments in Federal Law No. 241-FZ, 2012, requires owners and operators of transmission and distribution facilities to give preferential access to free capacities in the “Unified Gas Supply System” to associated gas. Federal Law No. 35-FZ on the Electric Power Industry, 2003, gives electricity producers from associated gas priority access to the wholesale market, second only to the electricity produced from system security capacity. Federal Law No. 225-FZ on Production Sharing Agreements, 1995, links renewals of PSCs to the rational use of subsurface resources.

4. Legislative Jurisdictions

Gas flaring and venting are matters of federal jurisdiction. However, Article 1 of Federal Law No. 2395-1 on Subsoil, 1992, grants local governments the right to further regulate flaring and venting within the limits of the relevant federal laws.

5. Associated Gas Ownership

Article 1 of Federal Law No. 2395-1 on Subsoil, 1992, states that subsurface natural resources in Russia are property of the state. In line with the principles applicable to concession systems, titles to resources once extracted are transferred to the producer. Based on the requirement to pay an emission pollution fee, as stated in Federal Law No. 7-FZ on Environmental Protection, 2001, and the related federal decrees, ownership of associated gas remains with the producer. In a limited number of instances, PSCs have been concluded. According to Article 9 of the Federal Law No. 225-FZ on Production Sharing Agreements, 1995, titles to a part of the production is transferred to the contractor under the terms of the PSC.

C. Regulatory Governance and Organization

6. Regulatory Authority

Overall responsibility for overseeing subsurface resources, including policies for flaring and venting of associated gas, lies with the Ministry of Natural Resources and the Environment.497 Federal Law No. 7-FZ on Environmental Protection, 2001 (see footnote 494) established a specialized authority. This law assigns responsibility for oversight of compliance with energy regulation to the Federal Service for Supervision of Natural Resources.498 Article 3 of Federal Law No. 2395-1 on Subsoil, 1992 (see footnote 493) establishes the Federal Agency for Mineral Resources503 as the central administrative agency for subsurface resources. It has no direct responsibilities regarding flaring and venting.

7. Regulatory Mandates and Responsibilities

In line with the clear separation between policy making, regulatory compliance monitoring, and service provision, federal ministries make policies and issue regulations. As part of its overall responsibility to oversee subsurface usage, the Ministry of Natural Resources and the Environment has issued an associated gas regulation for flaring and venting in its regulatory capacity. Federal agencies provide public services, manage state property, and maintain various types of registers. Flaring-specific responsibilities are covered in Federal Law No. 7-FZ on Environmental Protection, 2001, which entrusts the Federal Service for Supervision of Natural Resources with execution of those responsibilities. Section 4 of Federal Decree No. 255, 2017 (see footnote 496) assigns responsibility for calculating and collecting fees for pollutant emissions to this federal service. However, because of its authority in assessing the adequacy of the metering systems and establishing accounting procedures for associated gas, the Federal Ministry of Energy can indirectly influence the level of fees paid for flaring and venting (see sections 15 and 18 of this chapter).

8. Monitoring and Enforcement

Federal Law No. 7-FZ on Environmental Protection, 2001, in combination with Federal Decree No. 1148, 2012 (see footnote 490), assigns monitoring and enforcement powers to the Federal Service for Supervision of Natural Resources (see sections 3, 6, and 7 of this chapter).

9. Flaring or Venting without Prior Approval

No evidence regarding flaring or venting without prior approval could be found in the sources consulted.

10. Authorized Flaring or Venting

Federal Law No. 7-FZ on Environmental Protection, 2001 (see footnote 494) requires an environmental impact declaration (Article 31) and an EIA (Article 32) be carried out on economic or other activities that may directly or indirectly affect the environment.

11. Development Plans

Article 46 of Federal Law No. 7-FZ on Environmental Protection, 2001 requires oil and gas facilities to be designed and operated in a manner that is not harmful to the environment. Article 3 of Federal Law No. 2395-1 on Subsoil, 1992 (see footnote 493) gives the Federal Agency for Mineral Resources the powers to review and approve development plans and PSCs. These powers allow the agency to influence the use of associated gas in future oil production.

12. Economic Evaluation

No evidence regarding economic evaluations could be found in the sources consulted.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Article 22 of Federal Law No. 2395-1 on Subsoil, 1992 (see footnote 493) requires the oil and gas producer to submit to the Federal Geological Information Fund reliable information on volumes explored and produced. To ensure the uniformity of measurements, meters must meet the metrological and technical requirements as defined by a normative guideline issued by the Federal Ministry of Energy. Section 3 of Federal Decree No. 1148, 2012 (see footnote 490) requires oil producers to report their “flaring rate” – the percentage of associated gas that is flared and vented (see section 18 of this chapter).

14. Measurement Frequency and Methods

Section 3 of Federal Decree No. 1148, 2012, requires oil producers to report the flaring rate quarterly. Reporting requirements for well data other than flaring and venting can be more frequent.

15. Engineering Estimates

There is no mention of acceptable alternatives to metering. Section 5 of Federal Decree No. 1148, 2012, increases the fee for flaring and venting if no metering system is in place or the system used does not meet the Federal Ministry of Energy’s requirements.

16. Record Keeping

Operators must maintain measurement instrument readings and other technical equipment records, but there is no specific mention of flaring and venting.

17. Data Compilation and Publishing

No evidence regarding data compilation and publishing could be found in the sources consulted.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

Article 16 of Federal Law No. 7-FZ on Environmental Protection, 2001 (see footnote 494) specifies the procedures for calculating associated gas flaring or venting fees. Sections 1-7 of Federal Decree No. 1148, 2012 (see footnote 490) defines the key principles applicable to calculating these fees:

- The maximum admissible limit value for flaring and venting combined should be no more than 5 percent of the total

Russian Federation

associated gas volume, calculated by the flaring rate (Z),
\[ Z = \frac{S}{V} \times 100\% \], where \( S \) is the amount of associated gas flared and vented and \( V \) is the volume of associated gas produced.

Volumes flared during scheduled shutdowns are excluded from the calculations.

- Below the maximum admissible limit value, the fee calculation (using emission pollutants and environmental factors) as quoted in Federal Decree No. 913, 2016 (see footnote 495) applies without any additional multiplier uplift.
- Above the maximum admissible limit value, a multiplier (k-factor) of 25 applies to the calculated fee, up from the previous k-factor of 12, which was applicable until 2014.
- An additional k-factor of 120 applies if there is no metering system that meets the Federal Ministry of Energy requirements in place.
- Efforts to increase associated gas use are captured in a cost coverage indicator, which reduces the overall fee.
- Production of less than 5 million m\(^3\) a year and production with a hydrocarbon saturation of less than 50 percent can be exempt from additional fees.

Federal Decree No. 255, 2017 (see footnote 496) requires these fees to be paid in quarterly advance payments (except for the fourth quarter). Sections 1 and 3 empower the Federal Service for Supervision of Natural Resources to verify the fee calculations and collect the fees, which are not tax-deductible.

G. Enabling Framework

20. Performance Requirements
No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives
Fees related to gas flaring and venting are not tax-deductible. However, legal entities participating in several oil and gas projects across the value chain could benefit from fiscal consolidation, allowing them to offset profits from one project against losses from another. Depending on how profitable the other operations are, doing so could enable the utilization of associated gas, which would otherwise be flared or vented.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
Article 27 of Federal Law No. 69-FZ on Gas Supply, 1999 (see footnote 497) requires owners and operators of transmission and distribution facilities to give associated gas preferential access to free capacities. Article 32 of Federal Law No. 35-FZ on the Electric Power Industry, 2003 (see footnote 499) gives electricity produced from associated gas preferential access to the wholesale market.
United Kingdom

0.85 billion cubic meters of gas flared in 2021
(total oil production 808 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
<thead>
<tr>
<th>Year Range</th>
<th>% Change</th>
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</thead>
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<tr>
<td>2015-2021</td>
<td>-35%</td>
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<td>2015-2020</td>
<td>-19%</td>
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</table>

Change in Flare Gas Intensity**

<table>
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<th>Year Range</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015-2021</td>
<td>-29%</td>
</tr>
<tr>
<td>2015-2020</td>
<td>-24%</td>
</tr>
</tbody>
</table>

Note: Change values reflect the mean difference in flaring intensity from 2015 to 2020 and 2015 to 2021.

* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 19 Gas flaring volume and intensity in the United Kingdom, 2012–21

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Between 2012 and 2021, oil production in the United Kingdom fluctuated by about 15 percent from the mean, ending slightly lower in 2021 than in 2012. The volume of gas flared and the flaring intensity in the United Kingdom fell by about one-third during this period (figure 19). The total volume flared remained largely steady from 2012 to 2017, after which it began to fall. The flaring intensity was on a declining trend since 2014. There were 76 individual flare sites in the last flare count, conducted in 2019.

The United Kingdom endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2020 (World Bank, n.d.; see footnote 3). It also participates in the Global Methane Initiative (n.d.; see footnote 29) and the Climate and Clean Air Coalition (n.d.; see footnote 30). In December 2020, the United Kingdom submitted an updated NDC to the UNFCCC, in which the government committed to reducing economy-wide GHG emissions from the 1990 level by at least 68 percent by 2030.504 In June 2019, the government amended the Climate Change Act, 2008, to increase the reduction in the “net UK carbon account” below the 1990 baseline by 2050 from 80 percent to at least 100 percent.505 The updated NDC is intended to be consistent with the government’s new net-zero policy.506

Flaring and venting have been subject to the secretary of state’s consent for decades, per Section 12 of the Energy Act, 1976.507 Over the years, other legislation has been enacted that also covers flaring or venting. Between 2008 and 2016, the Department of Energy and Climate Change (now the Department of Business, Energy, and Industrial Strategy) provided flaring and venting consents on behalf of the secretary of state. The Energy Act, 2016, transferred certain powers from the secretary of state, including the issuance of consents for flaring and venting, to the Oil and Gas Authority (OGA),508 which was formed in 2015 within the Department of Energy and Climate Change. With the passage of the Energy Act, the OGA became an independent regulator. It is a government company, limited by shares under the Companies Act 2006, with the secretary of state for business, energy, and industrial strategy the sole shareholder.

Since its creation, the main objective of the OGA—it’s so-called Central Obligation—has been maximizing the economic recovery of oil and gas resources on the UK continental shelf (UKCS). This objective, known as MER UK, was established as a government priority in 2015 and was the driver for creating the OGA. MER UK became legally binding with the Infrastructure Act, 2015.509 The Energy Act, 2016, charged the OGA with pursuing MER UK.

In February 2021, after a review by Parliament, the OGA’s new strategy became legally binding for oil and gas companies licensed to operate in the United Kingdom.510 The new strategy expands the OGA’s Central Obligation and adds assistance to the secretary of state in meeting the net-zero target by reducing GHG emissions as far as possible from sources that include flaring and venting.

The North Sea Transition Deal, published in March 2021, illustrates how the OGA’s 2021 strategy is guiding the offshore oil and gas sector.511 One of the pillars of this deal is decarbonization—targeting a 50 percent reduction in GHG emissions from oil and gas production by 2030.512 This White Paper, a co-product of the “tripartite partnership” (government, the OGA, and industry), is not legally binding.

The compatibility of the original and the new components of the OGA’s new Central Obligation—maximization of oil and gas production and decarbonization—is not readily apparent. However, an analysis by the Committee on Climate Change513 identified reducing flaring and venting as well as methane leakage by means of better leak detection and repair as the least-cost options.
United Kingdom

for reducing GHG emissions within the oil and gas industry.156 Historically, although flaring and venting have accounted for less than 1 percent of total GHG emissions in the United Kingdom, they have accounted for nearly 25 percent of oil and gas industry emissions, mostly from flaring. The rest of the emissions in the oil and gas industry are primarily from captive generation of electricity for the industry’s own use. The OGA’s data suggest that the flaring intensity is high for a relatively small group of facilities. This information is used in benchmarking to improve their performance.

The North Sea Transition Deal commits to developing a methane action plan. The Methane Action Plan 2021 was subsequently published.157 It has six actions, the fourth of which aims to meet the goal of the World Bank’s Zero Routine Flaring before 2030 initiative with individual assets seeking to accelerate compliance. The Methane Action Plan 2021 sets the stage for benchmarking to improve performance.

In response to assisting the government with its net-zero emissions targets, including zero routine flaring by or before 2030, the primary industry association, Oil & Gas UK, released decarbonization targets, which the OGA incorporated in its tracking of flaring and venting. The current industry methane intensity commitment is 0.25 percent by 2025, with an ambition to reduce it to 0.20 percent (North Sea Transition Deal 2021). Net Zero Stewardship Expectation 11 states that “zero routine flaring and venting and the use of the lowest GHG emission fuels should be the base case for power generation and GHG emissions targets.”

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Energy Act, 2016 (see footnote 508) amends both the Energy Act, 1976 (see footnote 507) and the Petroleum Act, 1998,3157 and empowers the OGA to provide consent for flaring and venting. Building on the Petroleum Act, Petroleum (Current Model Clauses) Order 1999 was issued, outlining the restrictions on flaring and conditions when applying for consent to flare or vent.3158 These clauses are included in offshore licensing regulations.304

The environmental regulation relating to UKCS oil and gas activities is under the purview of the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED), which is part of the Department for Business, Energy and Industrial Strategy. OPRED has enforcement powers for all relevant environmental regulations,305 including those that apply to flaring and venting (see section B of this chapter).

Most relevant for flaring is OPRED’s responsibility in overseeing the compliance of the oil and gas industry with Greenhouse Gas Emissions Trading System Regulations, 2012.306 These regulations— which follow from the Climate Change Act, 2008 (see footnote 505) and the EU ETS Directive 2003/87/EC, 2003—establish the trading of GHG emissions allowances that affect flaring because of associated CO2 emissions. The UK EUETS replaced the EU ETS following the United Kingdom’s exit from the European Union, but the UK ETS follows the same approach as EU ETS Phase IV, which the United Kingdom played an important role in developing. Greenhouse Gas Trading Scheme Order 2020319 supplemented the 2012 regulations to reflect the net-zero target of the government.319 The Offshore Combustion Installations (Pollution Prevention and Control) Regulations, 2021318 amended the 2013 version to introduce consistency with EU Directive 2015/129 (EU).319

For venting, the National Emission Ceiling Regulations, 20183159 which implement EC Directive 2016/2286312, have a bearing, because the OGA considers both inert gases and hydrocarbons produced in the licensed area in consent to vent under the Energy Act, 1976. Vented gas may contain nitrogen, carbon dioxide, water vapor, hydrocarbons, and possibly traces of sulfur compounds in the consent application to the OGA (see footnote 519).

4. Legislative Jurisdictions

National laws and regulations govern flaring and venting. However, environmental agencies in Scotland, Wales, and Northern Ireland plug regulatory roles, especially with respect to GHG emissions. These agencies oversee compliance with the EU ETS. To ensure a smooth transition, the UK ETS follows EU ETS practices closely: a link between the two is desirable to many entities covered under the UK ETS.110 The same regulators oversee compliance with the UK ETS.

5. Associated Gas Ownership

Oil and gas resources are owned by the Crown and offered to companies under a concessionary regime with vast bureaucracy. Operators the OGA licenses to explore, develop, and produce petroleum onshore and offshore own all the oil and gas they extract.

6. Regulatory Authority

The OGA issues consents for flaring and venting under the Energy Act, 2016 (see footnote 508). Environmental regulation of the oil and gas industry, including compliance with flaring and venting consents, remains with OPRED for offshore operations and the Environment Agency for onshore operations.310 The Scottish Environment Protection Agency, Natural Resources Wales; the Northern Ireland Environment Agency within the Department of Agriculture, Environment and Rural Affairs; and the Environment Agency regulate GHG emissions from flaring at onshore oil and gas facilities. Each agency monitors and monitors the GHG permits and emissions plans of industrial facilities and aviation covered under the UK ETS in its jurisdiction. The Health and Safety Executive remains the safety regulator and takes the lead on offshore gas leaks.

7. Regulatory Mandates and Responsibilities

Section 12A of the Energy Act, 1976 (see footnote 507) as amended by the Energy Act, 2016, outlines the OGA’s functions and states that the OGA’s consent is required for flaring and venting. Historically, the OGA’s primary responsibility has been MER UK. Following the government’s announcement in June 2019 of a net-zero target, the OGA increased its focus on flaring and venting among the material sources of GHG emissions. Its 2021 strategy does not clarify how much GHG emissions from oil and...
United Kingdom

gas operations must be reduced, instead referring to of reducing GHG emissions "as far as reasonably practicable in the circumstances." The OGA Flaring and Venting Guidance, 2021 (see footnote 518) uses the same language but also targets zero routine flaring and venting in all new facilities and all existing facilities by 2030.

8. Monitoring and Enforcement

The OGA is authorized to sanction operators for failing to comply with any of the licenses under Chapter 5 of the Energy Act, 2016 (see footnote 508). However, the OGA does not inspect facilities for compliance with flaring or venting consents. In the past, inspectors from the Offshore Environmental Inspectorate, a department of the OGA’s predecessor, the Department of Energy and Climate Change, could conduct inspections, routine or as needed, of facilities for any licensed operation, including flaring and venting. The Offshore Environmental Inspectorate has since been moved to OPRED and carries out inspections.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

The Energy Act, 2016 (see footnote 508) amended the Energy Act, 1976 (see footnote 507). Under its Section 12A, approval for flaring or venting is no longer required if the operator can demonstrate that it is necessary to reduce or avoid the risk of personal injury, the risk could not reasonably have been foreseen in time to reduce or avoid it other than by flaring or venting, or it was not reasonably practicable to obtain consent in the time available.

10. Authorized Flaring or Venting

Under Section 12A of the amended Energy Act, 1976, consent from the OGA is required to flare or vent gas from upstream oil or gas and processing facilities. Operators must apply for these consents via the UK Energy Portal.534 The OGA used to provide separate guidance with regard to applications for flaring or venting consents during commissioning and production. The OGA Flaring and Venting Guidance, 2021 (see footnote 518) replaced these two guidance documents, but most requirements for authorization of flaring and venting remained the same.

The procedure for commissioning new facilities is summarized as follows:

- The OGA issues flaring or venting consents valid for about one month (up to three months) during the commissioning of new facilities.
- The amount of gas flared and vented is fixed and subject to an audit at the lowest level possible for safe and efficient commissioning.
- Consents are not issued until the OGA is satisfied that the gas-processing plant is ready to receive gas (construction complete, fully tested).
- If the gas-processing plant cannot handle all gas within two weeks of first oil, the OGA may limit production.
- Supporting documentation should be submitted to the OGA six months before the expected start-up.
- Formal written application should be made about two weeks before first oil.

The procedure for production is as follows:

- Consents for flaring or venting during production operations are issued after commissioning of the gas-processing plant is completed.
- Consents are annual, and leftover allowances cannot be carried forward.
- The operator must submit a new application every year (usually in October). One objective of the OGA is to use these applications to develop a realistic forecast against which to track performance.
- The OGA may issue consents of shorter duration if, for example, the level of flaring or venting raises concerns of more investigation or data are necessary.
- Flare (vent) consents are for a field, which may have multiple installations that flare (vent).
- Composite or group consents can be issued for several fields to common facilities when equity partners are the same or operators of fields and common facilities submit their agreement for a group consent.
- A new field connecting to an existing facility may obtain a new consent or may be added to the existing consent via a new application.
- Possible breaches must be reported to the OGA promptly, and a technical case must be made if a revision is required.
- Commissioning consent documentation may differ depending on the facility scale and complexity. At a minimum it should include the following:
  - a brief overview of the field and associated main facilities
  - a detailed description of the plant commissioning philosophy and procedure, including gas export line commissioning
  - the commissioning schedule
  - a summary of the main flaring and venting assumptions and GHG profiles under different commissioning strategies
  - forecasts of daily and total quantities of gas flared or vented
  - sketches and figures containing a high-level field layout, process flow diagrams, and systems for gas compression, dehydration, gas export, and fuel gas.

The OGA Flaring and Venting Guidance, 2021, also covers flaring and venting at terminals and other onshore facilities that serve offshore operations. However, consent applications for onshore facilities are submitted via email and not through the Energy Portal.

11. Development Plans

The OGA guidance on offshore field development plans must "demonstrate a commitment to preventing the unnecessary and wasteful flaring of associated gas and carrying out commissioning operations in an efficient and timely manner." Paragraphs 4.8–5.1 of the OGA requirements for UHCFS development plans ask for "a detailed technical and economic assessment" to justify flaring. Licensees are also required to design facilities for “less wasteful alternatives should the economic or technical circumstances change.”

Onshore guidance reflects the same principle of avoiding “unnecessary wastage” via flaring and venting.536

Net Zero Stewardship Expectation 11 asks the oil and gas industry to reduce GHG emissions from all aspects of its upstream operations “as far as reasonable in the circumstances.” Development plans for greenfield projects need to demonstrate “consideration and economic assessment of GHG Emissions Reduction Action Plans.” These plans include “zero routine non-safety-related flaring/venting” and “gas recovery systems” in addition to low-carbon electricity options, better GHG measurements, new technologies to reduce emissions, and coordination with others to create energy hubs to avoid duplication of infrastructure. The OGA Flaring and Venting Guidance, 2021, requires a Flaring and Venting Management Plan, which can be incorporated in the GHG Emissions Reduction Action Plan.

12. Economic Evaluation

Net Zero Stewardship Expectation 11 lists various expectations as applicable across the exploration, appraisal, development, production, late-life, and decommissioning phases of an oil and gas asset. Opportunities to reduce GHG emissions, including from flaring and venting, include improved measuring, reporting, tracking, and incorporating of net-zero targets in corporate decision making across all lifecycle phases of an asset.

Some design considerations for greenfield projects are relevant to flaring and venting (see the previous section). Both Net Zero Stewardship Expectation 11 and the North Sea Transition Deal call for a sharper focus on energy hubs, the sharing of facilities, and long-term planning for infrastructure repurposing.

Improved measurement and tracking of emissions are key requirements for better economic assessment by operators. The OGA asks to develop reduction strategies for flaring and venting. The OGA benchmarking analysis for flaring shows that some facilities have much lower flaring intensities than others. More accurate and detailed data are expected to improve the understanding of the lowest-cost approaches to reducing volumes of flared gas. The OGA is also developing a database for methane emissions, in order to replicate the benchmarking exercise for venting.

The OGA Flaring and Venting Guidance, 2021, formalizes these expectations. Operators are expected to demonstrate that they evaluated all options to reduce flaring and venting when applying...
for consents and when developing credible plans to reach zero routine flaring and venting.

E. Measurement and Reporting Requirements

According to the OGA Flaring and Venting Guidance, 2021 (see footnote 518), the flaring or venting consent granted during commissioning is intended to cover the period from first oil production to the achievement of stable operations (one to three months). The operator must provide weekly reports to the OGA detailing the activities from the previous week, including daily rates of oil and gas production and gas exported, flared, vented, or used as a fuel; cumulative plots of production, flaring, and venting compared with consented quantities and of associated emissions; and the status of gas compressors and gas-processing plants, highlighting anything that affected equipment or plant performance.

During production, unless specified otherwise in the consent, flaring volumes are included in routine reporting via the OGA Petroleum Production Reporting System via the Energy Portal (see footnote 534). Under the Petroleum Act, 1998 (see footnote 520), only the gas flared from the licensed area requires consent, but the OGA requires that the content of inert gases in the flare be provided for information.

The OGA Flaring and Venting Guidance, 2021, lists several reporting requirements. Flaring and venting must be allocated by source category. New in the OGA Flaring and Venting Guidance, 2021, source categories are made consistent with the World Bank’s Zero Operating Conditions report and the Environmental and Emissions Monitoring System. According to the latter system’s and ETS guidance (see next section). In the future, as highlighted in the OGA Flaring and Venting Guidance, 2021, the OGA expects operators to “meter, monitor and manage their flare gas composition and flame combustion efficiency” and to use “best available technology to quantify, measure and monitor vent gas.”

15. Engineering Estimates

The OGA Flaring and Venting Guidance, 2021, requires flare and vent volumes to be reported in mass units. OPRED’s Environmental and Emissions Monitoring System requires operators to report all emissions from all facilities involved in offshore oil and gas production in mass units. There are two main options:

1. Report total masses of emissions without component breakdown. The Environmental and Emissions Monitoring System then uses standard default factors to calculate emissions gases and halogenated compounds.

2. Report total and component emissions data from in-house systems (approved by the Department of Energy and Climate Change and, since 2016, by the OGA). This option enables operators to report data that are more representative of their facilities than those based on the standard factors used by the Environmental and Emissions Monitoring System.

The mass units used in reporting are usually tonnes, following guidance in the Atmospheric Emissions Calculations document (see footnote 544). GHG emissions associated with flaring are calculated using emissions factors, gas composition, and combustion efficiency assumptions from EU Regulation No. 651/2012. The EU ETS regulations require all operators subject to the directive to submit monitoring plans to regulators for approval. Historically, there has been an uncertainty range of ±7.5 percent for flare measurements submitted to regulators under the EU ETS scheme. In 2021, the UK ETS replaced the EU ETS, but in many respects, including measurements, the UK ETS mirrors Phase IV of the EU ETS to ensure a smooth transition.

16. Record Keeping

No explicit record-keeping requirement was identified from the sources consulted. The OGA strategy is to “influence” operator action through performance benchmarking and collaboration. Operators are urged to provide data on various aspects of their operations, as outlined in the OGA Stewardship Expectations.

17. Data Compilation and Publishing

A large amount of data can be downloaded from the OGA’s Open Data Service. In September 2020, the OGA published the UKCS Flaring and Venting Report, its first benchmarking report on flaring and venting using data submitted by oil and gas companies via the Petroleum Production Reporting System and Environmental and Emissions Monitoring System. According to the report, 0.05 percent of all produced gas in 2019 was vented, about 3 percent was flared, about 88 percent was exported, and the rest was used in operations, mainly for power generation. These shares remained fairly constant through the 2010s. About 60 percent of flare volumes were from baseloads, 30 percent from operational changes, and 10 percent from emergency shut-downs (see section 40 of this chapter). Separately, the OGA is expected to publish an annual flaring and venting benchmarking report.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

The OGA is authorized to sanction operators for noncompliance with any of the licenses it issues, including consents for flaring and venting. Chapter 5 of the Energy Act, 2016 (see footnote 508) on sanctions, details OGA’s disciplinary powers. Sanction notices can cover enforcement of “petroleum-related requirements,” financial penalties, revocation of licenses, and operator removal. Section 42 of Chapter 5 defines petroleum-related requirements, which include responsibilities imposed under Section 9C and 9A of the Petroleum Act, 1998 (see footnote 520), requirements under the Energy Act, 2016 (including flaring and venting consents issued by the OGA), and any term of offshore licenses issued by the OGA.

According to Sections 44–46 of Chapter 5, financial penalties are limited to £1 million (about US$1,400,000 as of October 2021), although the secretary of state can increase them up to £5 million (about US$6,800,000 as of October 2021). If a financial penalty notice is given to two or more parties, they are jointly and severally liable. The payment is recoverable as a civil debt if it is not paid before the deadline in the notice. Penalties must be paid into the Consolidated Fund. However, exact penalties must be defined in the guidance to be issued by the OGA. The most recent guidance from the OGA provides principles of best regulatory practices based on other regulators. Given its lack of experience with assigning financial penalties, the OGA will assess penalties for each violation according to the principles outlined in
United Kingdom

its guidance. It has not sanctioned any operator for violations of flaring or venting consents.\(^{550}\)

Civil penalties for flaring or venting range from £500 to £50,000 (about US$680–US$68,000, as of October 2021) and can be issued by OPRED under the Offshore Environmental Civil Sanctions Regulations 2018.\(^{551}\) In addition, OPRED, the Environment Agency, the Scottish Environment Protection Agency, and the Scottish Environment Protection Agency can impose civil penalties for breaches of the UK ETS under the Greenhouse Gas Trading Scheme Order 2021.\(^{552}\) These have become more prominent, as flaring is no longer eligible for free allowances under the EU ETS Phase IV, which started in 2021. The UK ETS is expected to align with the EU ETS Phase IV.

19. Nonmonetary Penalties

Under Chapter 5 of the Energy Act, 2016 (see footnote 509), nonmonetary penalties can increase in severity as follows:

- an enforcement notice informs an operator of its failure to comply with a petroleum-related requirement and may include directions for compliance (Section 43).
- a revocation notice declares that the license will be revoked by a certain date for failure to comply with a license requirement (Section 48).
- an operator removal notice announces the date of removal of an operator that had failed to comply with a license requirement (Section 48).

The OGA follows a "measured escalation" process before deciding whether to pursue sanctions.\(^{553}\) Before issuing sanctions for violations, the OGA may require regulatory-compliance plans and more frequent reporting of, for example, volumes of gas flared. The OGA requires that operators conduct "lessons learned" exercises following consent breaches to avoid similar breaches in the future. As part of its OGA’s progressively more proactive approach to using its powers in the future, the OGA Flaring and Venting Guidance, 2021 (see footnote 518) suggests a more stringent approach than in the past to sanctions in case of failure to comply with flare or vent consents.

OPRED also has enforcement powers associated with its environmental regulation of offshore oil and gas operations. Although the specifics may change according to individual regulations, inspectors from the Offshore Environmental Inspectorate can board offshore installations with any equipment necessary to conduct investigations into compliance, interview staff, and collect relevant data. If inspectors find noncompliance, enforcement actions can range from written notices to operators to ensure compliance for relatively minor violations to civil sanctions, revocation of permits, and prosecution for more serious or persistent noncompliance. Enforcement must be proportional to the violation, related to specific violations, consistent, transparent, and accountable.\(^{554}\)

6. Enabling Framework

20. Performance Requirements

Specific performance requirements on flaring or venting could not be identified in the official documents reviewed. The OGA implemented a benchmarking process based on the flaring and venting data it started collecting in July 2017. The data can be used to identify facilities that are performing worse than the industry average. The OGA anticipates that this benchmarking exercise will allow operators to learn best practices from others and to help them reduce their flaring and venting at the least cost. The OGA has had success with benchmarking in raising performance levels in production efficiency, unit operating costs, recovery factor, and decommissioning.\(^{555}\)

21. Fiscal and Emission Reduction Incentives

There is no carbon tax on GHG emissions associated with oil and gas activities, but emissions are covered under the UK ETS regime. There is a climate change levy on electricity, gas, LPG, and other energy sources derived from fossil fuels at the end-user level.\(^{556}\) In 2016, the Petroleum Revenue Tax was permanently eliminated; before the reform, it had been 50 percent. The supplementary charge was reduced to 10 percent, down from 20 percent under the Corporation Tax Act, 2010. These fiscal reforms were intended to facilitate MER UK. Despite industry expectations, the government did not offer any fiscal incentives for investments to mitigate environmental impacts, including flaring and venting.

22. Use of Market-Based Principles

All UCNS oil and gas facilities have been subject to EU ETS requirements. Following Annex I of the EU ETS Directive 2003/87/EC, 2003 (see footnote 525), these requirements cover offshore installations that emit CO₂ from combustion installations with a maximum thermal input exceeding 20 MW, including flares. Operations were provided free allocations if their compliance with the EU ETS put them at a competitive disadvantage in the global market (that is, if they were not able to reflect the cost of compliance in the price of their goods and services and lost market share as a result). A situation known as carbon leakage. As such, the EU ETS did not affect GHG emissions from flaring or most other oil and gas industry activities until recently.

In 2021, Phase IV of the EU ETS started. The changes in Phase IV exclude installations associated with gas extraction, including flaring, from the carbon leakage list. Accordingly, flare installations will receive only 30 percent of their emissions allocations free until 2026, after which the free allocation will decline to 0 percent by 2030. The United Kingdom played an integral role in the development of Phase IV, and the UK ETS is expected to follow the EU ETS closely. However, the cap is 5 percent lower than the United Kingdom’s share of Phase IV cap to support the net-zero target of the government. It is also possible that the two trading schemes will be linked in the future, although changes to the way the United Kingdom implements the ETS are possible.

23. Negotiated Agreements between the Public and the Private Sector

The 2021 North Sea Transition Deal is the most recent demonstration of the "tripartite partnership" between the government, the OGA, and the offshore oil and gas industry (as represented by Oil & Gas UK). This public-private partnership has been gaining prominence since MER UK became a legal objective of the UK government in 2015 and the net-zero target became a legal obligation in 2019. Although not legally binding, the North Sea Transition Deal aims to develop strategies for making the offshore oil and gas industry net-zero carbon by 2050. In line with the government target. Although GHG emissions from flaring and venting account for only about a quarter of UKCS Scope 1 emissions, the deal targets them as part of a holistic approach to reducing emissions.

24. Interplay with Midstream and Downstream Regulatory Framework

Liberalisation of the UK natural gas market began in the mid-1980s. There is wholesale and retail competition in this highly liquid market. Natural gas suppliers have regulated open access to midstream and downstream infrastructure. Timely development of this infrastructure is necessary to avoid delays in upstream production or flaring. If there is a need for new capacity, suppliers can develop new infrastructure or transact with independent midstream companies to develop the needed infrastructure. Companies operating in the natural gas midstream and downstream need a license from the independent regulator Ofgem.\(^{557}\)

Offshore producers need to develop infrastructure to deliver their associated gas to the national gas system. This infrastructure includes pipelines, terminals, processing plants, and storage facilities, some of which are located, offshore. If relevant, the OGA issues flaring and venting consents for these facilities. Environmental regulators have jurisdiction over these facilities as well as the rest of the national gas system.
United States

8.78 billion cubic meters of gas flared in 2021
(total oil production 11,187 thousand barrels per day)

Change in Flare Gas Volumes*

<table>
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Change in Flare Gas Intensity**

<table>
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<th>2015-2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Change</td>
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* Annual volumes in billion cubic meters
** Cubic meters of gas flared per barrel of oil produced

Figure 20 Gas flaring volume and intensity in the United States, 2012–21

United States: Federal Offshore

A. Policy and Targets
1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Crude oil production in the United States increased by about three-quarters between 2012 and 2021, while the volume of gas flared decreased from 9.5 bcm to 8.8 bcm (figure 20). This gradual decrease was interrupted by spikes in 2018 and 2019. Changes in the flaring intensity were also uneven: After falling during 2016 and 2017, the intensity rose sharply in 2018 and 2019 before falling to its lowest level since 2012 in 2021. Compared with 2012, the flaring intensity was about 45 percent lower in 2020. There were 2,655 individual flare sites in the last flare count, conducted in 2019.

The United States endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in 2016 (World Bank, n.d.; see footnote 3). It also participates in the Global Methane Initiative (n.d.; see footnote 30). In 2021, the United States rejoined the Paris Agreement and submitted a revised NDC report to the UNFCCC, 559 setting a target for reducing its net economy-wide GHG emissions by 50–52 percent below 2005 levels by 2030. The NDC does not mention flaring or venting, but reducing methane emissions from natural gas systems is cited among the important actions the United States plans to take to control non-CO₂ GHG emissions.

The Federal Outer Continental Shelf (OCS) 565 includes the Alaskan, Atlantic, Gulf of Mexico, and Pacific regions. The western (beyond nine nautical miles of Texas waters) and the central (beyond three nautical miles of Louisiana, Mississippi, and Alabama waters) planning areas of the Gulf of Mexico produce about 97 percent of all OCS oil and gas production. 561 The share of federal offshore oil in total US production peaked at about 30 percent in the early 2000s and fell below 15 percent by 2020. The share of federal offshore gas in total gas production was about one-fifth throughout the 1980s and 1990s but started to decline in the early 2000s and fell below 3 percent in 2019. In the 2010s, about 1.25 percent of the total OCS gas production was flared or vented, of which 70–80 percent was associated gas from oil wells. Of the gas flared and vented, 60–70 percent was flared, and the remainder was vented (see footnote 561). With limited exceptions, flaring and venting have been prohibited in federal onshore and offshore oil and gas operations since the late 1970s, but several assessments by the Government Accountability Office (GAO) and the Department of the Interior and its offshore regulators over the years have found shortcomings in regulatory practice and technology implementation that may have prevented maximum possible reduction in the volumes flared or vented. For example, a 2010 GAO report 564 found a large discrepancy between offshore operators, which reported flared and vented gas at 0.5 percent of gas production, and the Environmental Protection Agency (EPA), which estimated the share of flared and vented volumes at 2.3 percent. The GAO made several recommendations to the regulator to consider reducing the volumes flared or vented, including adoption of the best available technologies.

In 2011, the offshore regulator, Minerals Management Service, was separated into the Bureau of Ocean Energy Management (BOEM), 562 to assess and manage offshore energy resources; the Bureau of Safety and Environmental Enforcement (BSEE), 563 to regulate safety and environmental impacts; and the Office of Natural Resources Revenue (ONRR), 564 to manage royalty revenues. The GAO recommendations were addressed mainly by BSEE and BOEM. BSEE continues to pursue regulatory and technological options to reduce flaring and venting further while collaborating with BOEM on the economic viability of options. BSEE is responsible for regulating air emissions in offshore oil and gas facilities in the Gulf of Mexico.

In 2014, the President’s Climate Action Plan set a goal of cutting methane emissions from oil and gas operations by 40–45 percent...
United States: Federal Offshore

from the 2012 level by 2025.666 In June 2016, the United States, Mexico, and Canada committed to reducing methane emissions from the oil and gas sector by 40–45 percent by 2025.667 Also in 2016, the EPA issued the New Source Performance Standards (NSPS) for new stationary sources of air pollution, including methane emissions from upstream and midstream oil and gas operations.668

President Trump reversed some of these regulatory reforms with Executive Order 13783, Promoting Energy Independence and Economic Growth, 2017669 which called for federal agencies to review and, as appropriate, revise or annul existing regulations that could burden the development of domestic resources. In 2020, the EPA rescinded significant portions of the 2016 NSPS, including methane emissions from oil and gas operations.670

In early 2021, President Biden issued Executive Order 13990 on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis. 2021671 It directs all federal agencies to review all legal and regulatory rules issued by the previous administration and rescind or revise any that are inconsistent with the policy stated in this order. In particular, it tasked the EPA with revising 2020 amendments to the NSPS rule and developing new guidelines for methane emissions across the oil and gas industry by September 2021. On November 15, 2021, the EPA released the proposed rule on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.672 In parallel, the United States, together with the European Commission, also launched the Global Methane Pledge,673 a voluntary commitment to reduce global methane emissions by at least 30 percent from 2020 levels by 2030.

2. Targets and Limits

Title 30 Code of Federal Regulations (CFR) § 250.16060 defines limits within which gas can be flared or vented. For example, the amount is limited to what is necessary for its intended purpose, or an average of 50,000 cubic feet (mcf) a day in any calendar month.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Outer Continental Shelf Lands Act, 1953,674 is the overarching legislation governing offshore oil and gas activities and defining the federal role in regulating them. Title 43 U.S. Code § 134(h) has prohibited flaring since September 18, 1978, unless the secretary of the interior finds that gas capture is not practicable or that flaring is necessary to alleviate an emergency or conduct testing or work-over operations.675 Title 30 CFR § 250.16060 (see footnote 574) defines limited conditions under which BSEE can approve flaring or venting. It issues guidance, primarily in the form of Notices to Lessees (NTLs), to clarify procedures and requirements for these approvals.

The Outer Continental Shelf Lands Act, 1953, directs the Department of Interior to administer regulations for compliance with the National Ambient Air Quality Standards set in the Clean Air Act, 1970,676 which were amended in 1977 and 1990, to prevent significant damage to the air quality of any state as a result of offshore activities approved by the Department of Interior’s offshore regulator.677 The BSEE is responsible for ensuring compliance with the National Ambient Air Quality Standards in the Gulf of Mexico and Alaska. The EPA is responsible for air quality regulation in other federal waters under various programs of the Clean Air Act, 1990. The NSPS are issued and updated by the EPA under section 111678 of the Clean Air Act. The 2016 NSPS developed by the EPA allowed for regulating emissions of methane and other GHGs in addition to volatile organic compounds. Significant portions of the 2016 NSPS were rescinded in 2020; they may be reinstated (see section 1 of this chapter).

4. Legislative Jurisdictions

Federal laws govern flaring and venting in federal offshore fields, and national regulators regulate these practices. In state waters (nine nautical miles in Texas and three nautical miles elsewhere), state law regulated flaring and venting, and state entities regulate them.

5. Associated Gas Ownership

The federal government owns all oil and gas in the federal OCS.679 Energy firms access oil and gas in the OCS through concessions (leases) from BOEM (see footnote 560). The concession grants the right to explore for and, if a commercial discovery is made, own, develop, and produce the oil and gas. Royalties are not paid on unavoidably lost gas, which includes flared and vented volumes under certain conditions (see section 21 of this chapter).

6. Regulatory Authority

The BSEE has the authority to regulate flaring and venting, including air emissions from them. The EPA has jurisdiction over offshore emissions as well.

7. Regulatory Mandates and Responsibilities

The Minerals Management Service was reorganized into BOEM, the BSEE, and the ONRR to primarily eliminate conflicts between managing revenues from oil and gas leasing and regulating safety and environmental aspects of offshore oil and gas operations within the same agency. Several reports by the Department of Interior’s Inspector General detail the close relationship between members of the regulatory-in-kind program of the Minerals Management Service (terminated in 2010) and operators’ employees, the lack of resources limiting the ability of the Minerals Management Service to inspect an increasing number of offshore operations, and the industry’s practice of opposing potential Minerals Management Service regulations deemed uneconomical.680

The BSEE is an independent regulator focusing on the safety and environmental aspects of offshore oil and gas operations, including flaring and venting. The BSEE, often working in coordination with BOEM, is also responsible for regulating air emissions from offshore oil and gas operations in the western and central Gulf of Mexico and the Alaska OCS Chukchi and Beaufort Seas. The BSEE’s Environmental Compliance Program ensures compliance with air emissions laws and regulations. BOEM requires air emissions monitoring and reporting plans. The Environmental Compliance Program also ensures compliance with those plans (see footnote 578). The EPA regulates air emissions in all other federal waters.

8. Monitoring and Enforcement

The BSEE can conduct inspections and audits. Inspection procedures are intended to ensure compliance with Sections 1160 and 1163 of Title 30 CFR § 250 (see footnote 572). In 2015, the BSEE issued additional guidance on inspection procedures and the flaring or venting of low-volume flash gas from low-pressure equipment.681 Inspectors must verify operator calculations of flared and vented volumes, proper recording, and record maintenance according to standard operating procedures for measurement inspections. The BSEE requires inspectors to witness 10 percent of the accuracy tests for oil sales meters and 5 percent of the accuracy tests for gas meters. The BSEE’s inspectors issue a document for an incident of noncompliance if an operator fails to prepare and maintain records for all gas flared or vented. Prompt notification is required if the inspector observes that the gas volume routinely flared or vented at a facility exceeds 50 mcf a day and the...
United States: Federal Offshore

operator is unable to verify approval. The BSEE’s personnel for the Environmental Compliance Program can conduct risk-based offshore inspections to test that equipment that emit air pollutants is working correctly and that emissions levels comply with the National Ambient Air Quality Standards (see footnote 577 and 578).

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Flaring or venting are permitted without BSEE’s approval under a limited number of circumstances, listed in Title 30 CFR § 250.1160(a)(see footnote 574).

• when natural gas is used to operate production facilities or as an additive to burn waste products
• during the restart of a facility that had been shut in because of weather conditions, such as a hurricane
• during the blow-down of transportation pipelines downstream of the royalty meter
• during the unloading or cleaning of a well, drill-stem testing, production testing, other well-evaluation testing, or the blow-down necessary to perform these procedures
• when equipment fails to work correctly during equipment maintenance and repair or when system pressure must be relieved
• when the equipment works properly but there is a temporary upset condition.

10. Authorized Flaring or Venting

An operator must receive approval from the BSEE regional supervisor to flare or vent natural gas, except in the circumstances specified above. Following the recommendations of the 2011 GAO report (see footnote 562), the BSEE tightened the approval process, as communicated in NTL No. 2012-N04, this tightening led to a significant decrease in flaring or vent approvals. NTL 2020-N04supersedes previous NTLs on flaring and venting the approval process, as communicated in NTL No. 2012-N03 provides guidance on a case-by-case basis, with the following exceptions:

• The exception is in the national interest, such as when a major hurricane causes infrastructure damage. Bureau Interim Directive 2015-00758 requires that top BSEE management grant this exception.186
• The operator claims that production from the well completion would likely be permanently lost if the well were to be shut in. According to Bureau Interim Directive 2015-0070, the BSEE’s resource conservation personnel must analyze necessary data from wells to confirm all such claims.
• The operator claims that short-term flaring or venting would likely yield a smaller volume of lost natural gas than if the facility were shut in and restarted later. According to Bureau Interim Directive 2015-0070, the BSEE’s resource conservation personnel must analyze necessary data from wells to confirm all such claims.

According to Title 30 CFR § 250.1161(see footnote 574), approval for an extended period is possible but cannot exceed one year. The BSEE may approve requests for extended periods of flaring if the operator can demonstrate actions that will eliminate flaring and venting or demonstrates that lease economics do not support investment in eliminating flaring or venting.

11. Development Plans

According to Title 30 CFR § 250.1160(a)(see footnote 574), regardless of the exceptions, operators must not exceed the volume approved for flaring or venting in the Development Operations Coordination Document187 submitted to BOEM.

12. Economic Evaluation

Following the recommendations of the 2010 GAO report (see footnote 562), the BSEE implemented pilot studies with infrared cameras and, jointly with BOEM, conducted a study on the economic viability of further reductions by adopting various technologies. As a result, the agencies decided not to extend capture requirements to lease-use gas sources, pending further studies. The BSEE and BOEM also analyzed data from Gulfwide Offshore Activity Database System. They concluded that “flaring currently vented methane and replacing high-bled pneumatic controllers with zero- or low-bled pneumatic controllers would likely provide the greatest opportunities for meaningful and cost-effective emission reductions.” According to NTL No. 2020-N04, the BSEE does not consider the avoidance of lost revenue as a justification for approving flaring or venting. For example, if gas production or transportation infrastructure needs to be repaired and a well must be shut in during repairs, the BSEE will not allow operators to flare or vent gas to avoid shutting in the well and maintain the same pace of oil sales. Violations can result in civil or criminal penalties (see sections 18 and 19 of this chapter).

E. Measurement and Reporting

13. Measurement and Reporting Requirements

According to Title 30 CFR § 250.1563188 offshore facilities processing more than an average of 2,000 barrels of oil a day must install flare or vent meters. NTL No. 2012-N03 provides guidance on the BSEE procedures and requirements for installing meters.189 Measurements must be within 5 percent accuracy. Operators must use and maintain meters for the facility’s life. Meters must be calibrated regularly according to the manufacturer’s recommendation, or at least once every year, whichever is more frequent.

All hydrocarbons produced from a well completion, including all gas flared or vented and liquid hydrocarbons burned, must be reported to the ONRR on Form ONRR-4054 (Oil and Gas Operations Report [OGOR]), per Title 30 CFR § 250.1112186. Since September 15, 2010, leaseholders must specify the volumes of gas flared and vented separately in OGOR Part B. They must use different disposition codes for flared oil-well gas, flared gas-well gas, vented oil-well gas, and vented gas-well gas.190 The 2016 GAO report found that the ONRR’s guidance on reporting emissions from lost, whether flared or vented, lacked specificity.191 In reports, operators may classify gas used to operate lease equipment as lease-use gas. Where required, the amounts of gas flared and vented at each facility must be reported separately from that of facilities that do not require meters and separately from other facilities with meters. Flaring and venting from multiple facilities on a single lease or unit may be reported together.

14. Measurement Frequency and Methods

According to Title 30 CFR § 250.1563, offshore facilities processing less than an average of 2,000 barrels of oil a day do not have to install meters. Where meters are not required, gas flared and vented may be reported on a lease or unit basis. The BSEE does not prescribe estimation methodologies, but according to Title 30 CFR § 250.1203186 the estimation method of gas lost or lease-use gas must be documented along with the data used.

15. Engineering Estimates

According to Title 30 CFR § 250.1563, offshore facilities processing less than an average of 2,000 barrels of oil a day do not have to install meters. Where meters are not required, gas flared and vented may be reported on an individual lease or unit basis. The BSEE does not prescribe estimation methodologies, but according to Title 30 CFR § 250.1203 the estimation method of gas lost or lease-use gas must be documented along with the data used.

16. Record Keeping

According to Title 30 CFR § 250.1563, leaseholders must prepare records detailing gas flaring, gas venting, and liquid hydrocarbon burning for each facility and estimation methods used and maintain the records for six years. They must keep these records at the facility for at least the first two years; after two years, records must be available for inspection by BSEE representatives. At a minimum, the records must include the following:

• daily volumes of gas flared, gas vented, and liquid hydrocarbons burned
United States: Federal Offshore

- the number of hours of gas flaring, gas venting, and liquid hydrocarbon burning, on a daily and monthly cumulative basis
- a list of the wells contributing to gas flaring, gas venting, and liquid hydrocarbon burning, along with gas-to-oil ratio data
- reasons for gas flaring, gas venting, and liquid hydrocarbon burning
- documentation of all required approvals

17. Data Compilation and Publishing
The following data sources contain historical data on flaring and flaring volumes and GHG emissions associated with oil and gas production on the OCS:
- the Technical Information Management System
- the Gulfwide Offshore Activity Database System
- Oil and Gas Operations Reports Part A and Part B.

The first two databases are maintained by BOEM; the ONRR is responsible for the third. Following the recommendations of the 2010 GAO report (see footnote 562), BOEM reconciled differences in reported offshore flaring and venting volumes between the OGOR and the Gulfwide Offshore Activity Database System.

There are other data sources on flaring and venting, all of them much less disaggregated than the above three. The Energy Information Administration makes available online data that include flared and vented volumes, aggregated by region.593 The BSEE communicates the penalties, which are updated periodically, to operators. NTL 2021-NO1 sets the maximum penalty of US$46,000 a day per violation, effective May 4, 2021.594 The NTL contains a matrix of three categories of violations from A to C, broadly increasing with the severity of safety or environmental impacts, resulting in three increasingly onerous government responses: warning, component shut-in, and facility shut-in. A warning for a category A violation has the lowest penalty, with an assessment starting point of US$17,200 a day per violation, but the actual penalty can drop below that. A facility shut-in for enforcement of category C has the highest penalty, with an assessment starting point of US$54,500. If it is not paid, the facility can be shut in.

Failure or refusal to permit inspections or audits may be penalized by a fine of up to US$10,000 a day per violation (Title 30 CFR § 250.1460).595 An appeal can be made within 60 days by providing documentation of all required approvals, or facility shut-in if there is an immediate threat to safety and environment or operators fail to correct previously identified violations or pay assigned penalties.

G. Enabling Framework
20. Performance Requirements
US environmental law includes detailed requirements for flare design. Title 40 CFR § 60.58596 provides general requirements for flares; other subparts include more details. Title 40 CFR § 63.98597 requires a flare compliance assessment, provides certain technical details, and refers to other sections of the law for submitting flare compliance assessments (§ 63.999(a)(2)) and keeping records (§ 63.998(a)(1)). Title 40 CFR § 63.11598 (see footnote 599) provides detailed performance requirements for flare design. For example, there should be no visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours; a flame should always be present; and the heat content of gas and the exit velocity must be calculated using the formulas provided in § 63.11. Taken together, environmental regulations require that flares be operated and maintained in a manner consistent with ‘good air pollution control practices,’ typically interpreted to mean a combustion efficiency of 98 percent.

Title 40 CFR § 63.11 also provides alternative practices for monitoring leaks. Standard practices for monitoring leaks are provided in other parts of Title 40, including § 60, which apply to any stationary source subject to the NSPS, and § 61 and § 63, which apply to hazardous air pollutants. Appendix A-7 of § 60 details calculation methodologies for all regulated emissions, including volatile organic compound leaks, that are applicable for a diverse set of facilities.

21. Fiscal and Emission Reduction Incentives
If flaring or venting occurs without the required approval, or the BSEE regional supervisor determines that the operator was negligent or could have avoided flaring or venting, the hydrocarbons are considered avoidably lost or wasted and subject to royalties (12.5 percent in old leases, 16.67 percent in shallow waters, and 18.75 percent in deep water), according to Title 30 CFR § 1202.599 Operators must value any gaseous or liquid hydrocarbons avoided lost or wasted under the provisions of Title 30 CFR § 1206.600 Fugitive emissions from valves, fittings, flanges, pressure relief valves, or similar components do not require approval under this subpart unless specifically required by the regional supervisor. The BSEE Resource Conservation Section is responsible for informing the ONRR about noncompliance with regulations resulting in a loss of hydrocarbons from flaring or venting that could have been avoided and the volumes involved.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions from the Gulf of Mexico could be found in the sources consulted. There is no national carbon tax or market in the United States. The CO2 cap-and-trade market in California covers oil and gas operations there. An increasing number of states are pursuing cap-and-trade markets, but typically not in states with large oil and gas production.601 The petroleum industry supports a carbon tax but not if there are also new methane and other emissions regulations.602

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
The US natural gas market is highly liquid and gas infrastructure is vast. Most of the transportation pipeline and storage infrastructure operate as regulated open access facilities. Federal and state regulators share responsibility in licensing midstream

F. Fines, Penalties, and Sanctions
18. Monetary Penalties
Title 30 CFR Subpart N provides details on OCS civil penalties.603 The BSEE can impose such penalties if it determines that there is a violation (that is, a failure to comply with the Outer Continental Shelf Lands Act or its implementing regulations, any other applicable laws, or the terms of leases, licenses, permits, rights-of-way, or other approvals, including those for flaring or venting).

The BSEE communicates the penalties, which are updated periodically, to operators. NTL 2021-NO1 sets the maximum penalty of US$46,000 a day per violation, effective May 4, 2021.594 The NTL contains a matrix of three categories of violations from A to C, broadly increasing with the severity of safety or environmental impacts, resulting in three increasingly onerous government responses: warning, component shut-in, and facility shut-in. A warning for a category A violation has the lowest penalty, with an assessment starting point of US$17,200 a day per violation, but the actual penalty can drop below that. A facility shut-in for enforcement of category C has the highest penalty, with an assessment starting point of US$54,500. If it is not paid, the facility can be shut in.

Failure or refusal to permit inspections or audits may be penalized by a fine of up to US$10,000 a day per violation (Title 30 CFR § 250.1460).598 An appeal can be made within 60 days by providing documentation of all required approvals, or facility shut-in if there is an immediate threat to safety and environment or operators fail to correct previously identified violations or pay assigned penalties.

19. Nonmonetary Penalties
Title 30 CFR § 250.1409 provides for further sanctions if penalties are not paid. They may include the cancellation of the lease, right-of-way, license, permit, or approval; the forfeiture of a bond; or the barring of the violator from doing further business with the federal government. The BSEE enforcement tools include component or facility shut-in if there is an immediate threat to safety and environment or operators fail to correct previously identified violations or pay assigned penalties.
United States: Federal Offshore

and downstream infrastructure and regulating open access (for example, setting pipeline tariffs). Pipelines that cross state boundaries are subject to the oversight of the Federal Energy Regulatory Commission. Intrastate facilities are regulated by state regulators. Typically, independent midstream companies develop pipeline, processing, and storage facilities when they see opportunities to connect new production to consumers. Sufficient numbers of shippers or users must sign up for new capacity for midstream companies to justify investment. If midstream companies are not interested, it may be necessary for upstream companies, especially in offshore, to invest in pipelines. Delays in midstream infrastructure development have been a key reason for increased flaring in onshore upstream operations (see the chapters on Colorado, North Dakota, and Texas).

The policy of the Federal Energy Regulatory Commission for analyzing GHG emissions associated with gas pipeline projects has been uncertain since about 2016. Arguments for including emissions from upstream (oil and gas production activities that supply the gas) and downstream (use of gas carried by the pipeline such as power generation) in the commission’s review of pipeline applications have led to court cases and disagreements among commissioners. In early 2021, the Federal Energy Regulatory Commission, for the first time, considered GHG emissions associated with pipeline construction and operation during its review of a pipeline. This change in the Federal Energy Regulatory Commission’s pipeline approval criteria may have unintended consequences by delaying pipeline development and causing increased flaring or venting of associated gas.

United States: Federal Onshore

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

The US flaring data and international agreements are described in section 1 of the previous chapter, on the US federal offshore production. According to the Energy Information Administration, the states of Texas, North Dakota, and New Mexico account for 90 percent of total national flaring in 2018. The share of onshore oil production on public lands has been declining for years. It fell below 9 percent of total onshore gas production in 2020.

The share of onshore oil production on public lands has been increasing slowly for years. It picked up pace after 2015, thanks to increased drilling and development in tight oil plays, reaching 10 percent of total onshore oil production in 2020. The share of onshore gas production on public lands has been declining for years. It fell below 9 percent of total onshore gas production in 2020.

Flaring and venting from oil and gas operations on public lands has been regulated by the Department of the Interior’s Bureau of Land Management (BLM) since 1980. In a 2010 report, the GAO identified opportunities to reduce flared and vented gas in federal onshore and offshore fields to increase royalties and reduce GHG emissions (see footnote 562). In a 2016 report, the GAO identified gaps in the regulation of flaring and venting in federal onshore fields by the BLM and the Department of Interior’s ONRR (see footnote 591).

In 2016, the President’s Climate Action Plan set a goal of cutting methane emissions from oil and gas operations by 45–48 percent below the 2012 level by 2025 (see footnote 566). In response, the BLM issued the 2016 Waste Prevention Rule, which targeted the reduction of flaring and venting via a series of new measures, including some of the recommendations from the 2016 GAO report. The BLM’s 2016 Waste Prevention Rule has been fully implemented, because of legal challenges from states and industry groups. By 2020, parts of it had been either rescinded by the BLM’s revisions or vacated by court rulings in response to legal challenges by several states and industry groups. Other states and environmental groups have been litigating to reinstate the 2016 Waste Prevention Rule. At the time of writing, the BLM regulation had mostly reverted to rules set in 1980.

In 2016, the EPA issued the NSPS, which include methane emissions from oil and gas operations. An Executive Order from President Trump rescinded the clauses related to methane emissions in 2020. An Executive Order from President Biden directed federal agencies to reinstate the regulations (see section 1 of the previous chapter).

2. Targets and Limits

The BLM’s 2016 Waste Prevention Rule introduced monthly limits for onshore flaring per well, but court rulings partially vacated the rule (see section 12 of this chapter).

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The BLM has the authority to manage and regulate public lands under the Federal Land Policy and Management Act, 1976. Title 30 US Code (Mineral Lands and Mining), as amended over the years, outlines various regulators’ roles in, and general principles for, oil and gas leasing.

BLM Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases. Royalty or Compensation for Oil and Gas Lost, 1980 (NTL-4A) is the key document governing the regulation of flaring and venting on public lands. Title 43 CFR Subpart 3178 superseded sections in NTL-4A. The 2016 Waste Prevention Rule A court ruling vacated parts of the BLM’s 2016 Waste Prevention Rule. However, President Biden’s Executive Order may reinstate the rule. Various sections of this chapter discuss the relevant clauses.

References:

611 From the perspective of oil and gas leasing and regulation of flaring and venting, federal and Indian lands are treated under same legal and regulatory structure, with some exceptions. The term ‘onshore’ includes both state and federal onshore public lands. The term ‘federal’ refers to lands managed by the Bureau of Land Management (BLM).
615 Title 43 CFR Subpart 3178 superseded sections in NTL-4A. The 2016 Waste Prevention Rule A court ruling vacated parts of the BLM’s 2016 Waste Prevention Rule. However, President Biden’s Executive Order may reinstate the rule. Various sections of this chapter discuss the relevant clauses.
United States: Federal Onshore

C. Regulatory Governance and Organization

6. Regulatory Authority

The Department of Interior’s BLM regulates flaring and venting from oil and gas leases on onshore federal and Indian lands. State regulators or tribal authorities may have rules, regulations, or orders governing flaring or venting of oil-well gas emissions from flaring and venting. The BLM’s regional supervisors ratify such rules and any flare or vent authorizations issued by appropriate state regulators. The EPA has regulatory jurisdiction over air emissions from flaring and venting.

7. Regulatory Mandates and Responsibilities

The BLM has independent statutory responsibilities to prevent the waste of mineral resources, including oil and gas, in the course of their extraction from public lands. The BLM and state authorities may disagree, as demonstrated by the 2016 Waste Prevention Rule and the legal challenges that followed its issuance (see section 1 of this chapter).

The BLM and the EPA have no overlapping or conflicting mandates. However, it is possible that the new methane regulations the EPA proposed in November 2021 will prove, upon analysis, to be more stringent than the BLM’s present rules—obliging the BLM to develop waste prevention rules consistent with the ultimate EPA regulations. Energy and environment regulators in states have historically adapted national regulations such as the EPA NSPS to their own conditions. These regulations often overlap and can create uncertainty.

8. Monitoring and Enforcement

The BLM Oil and Gas Program conducts inspections—averaging 30,000 annually since 2010—to ensure compliance with federal and Indian laws, regulations, policies, and permit conditions of approval. Title 40 CFR Subpart 316 defines enforcement actions in case of noncompliance. The BLM has the authority to impose financial and nonfinancial penalties.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

According to NTL-44 (see footnote 615), flaring or venting is allowed without royalty obligation or prior authorization from the BLM if volumes are considered “unavoidably lost,” defined as follows:

- Volumes are lost during temporary emergencies, such as the failure of a compressor or other piece of equipment, relief of abnormal system pressures, or other conditions that result in flaring or venting of gas. Such venting or venting cannot exceed 24 hours per incident or a cumulative total of 944 hours for the lease during any calendar month.
- Volumes are lost during the unloading or cleaning up of a well during routine evaluation tests. Such flaring or venting cannot exceed 24 hours.
- Volumes are lost during initial production tests, not exceeding 30 days or 50 mcmf of gas, whichever occurs first.
- Gas vapors are released from storage tanks or other low-pressure production vessels. A BLM regional supervisor may determine that operators must recover such vapors.
- Oil and gas are lost as a result of line failures, equipment malfunctions, blowouts, fires, or similar events. If a BLM regional supervisor determines that the loss resulted from the negligence or failure of the operator to take all reasonable measures to prevent the loss, losses cannot be classified as “unavoidably lost.”

10. Authorized Flaring or Venting

According to NTL-44, prior authorization from a BLM regional supervisor is required if emergency flaring is expected to last longer than 24 hours. If a longer period of production testing is necessary, state regulators, if applicable, must authorize it, and the BLM regional supervisor must ratify this authorization.

Gas from a gas well cannot be flared or vented. Except when it falls under the “unavoidably lost” category (see the previous section), associated gas from oil wells cannot be flared or vented without written approval from a BLM regional supervisor.

11. Development Plans

The BLM’s 2016 Waste Prevention Rule required that a waste-minimization plan be submitted along with the application for an oil well drilling permit. The BLM rescinded this requirement in 2018. According to the BLM’s justification, at least some states have comparable gas capture requirements.

12. Economic Evaluation

According to NTL-44, BLM regional supervisors consider the economics of a field-wide plan for oil and gas production for the leasehold. The BLM may approve an application for flaring or venting associated gas from oil wells if either of the documents below could justify the proposed action:

- A technical and economic report by the operator demonstrating that the expenditures necessary to market or beneficially use gas are not economically justified and
- Conservation of the gas, if required, would lead to the premature abandonment of recoverable oil reserves and ultimately to a greater loss of equivalent energy than would be recovered with flaring or venting of the gas.

An action plan from the operator that will eliminate flaring or venting within a year from the date of application.

However, a 2016 GAO report (see footnote 595) found that the BLM’s field offices approved a large percentage of flaring and venting requests without the documentation required in the BLM’s guidance. About half of the approved operations were allowed to flare royalty-free. The GAO also observed that the BLM’s field offices had applied BLM guidance inconsistently and sometimes with significant differences. The rapid increase in drilling activity in tight oil and other unconventional plays since the early 2010s led to a significant increase in the number of applications for various permits to the BLM’s regional offices, overwhelming staff.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

According to NTL-44 (see footnote 615), *the volume of oil or gas...
produced, whether sold, avoidedly or unavoidabley lost, vented or flared, or used for beneficial purposes must be reported. The definition of beneficial purposes in NTI-4A is superseded by Title 43 Subpart 3179 (see footnote 614), which primarily defines conditions for qualification as lease-use gas. Operators must also report to the regional supervisor "the volume and value of all oil and gas which is sold, vented or flared without the authorization" [of the supervisor], or those volumes deemed by the supervisor to be avoidably lost.

All hydrocarbons produced from a well completion, including all gas flared, vented, and liquid hydrocarbons burned, must be reported on Form ONRR-4054, per Title 30 CFR § 1210.102 (see footnote 589). As with federal offshore, since September 15, 2010, leaseholders must specify flaring and venting volumes separately in OGOR Part B. They must use different disposition codes for flared-off-land gas, flared-gas-well gas, vented-oil-well gas, and vented gas-well gas (see footnote 590).

According to Title 43, if the amounts of oil or gas involved have been measured, the measured volumes must be reported. Estimation criteria are provided. Metering is not required, but the BLM's regional supervisors may require the installation of additional measuring equipment if the goals of NTI-4A are not met with existing equipment or estimation methods. Separately, operators must follow the guidance of Title 43 Subpart 3175 on gas measurement. The subpart has clauses on gas metering technology, hardware, and software requirements for metering, performance standards, and record-keeping requirements to ensure accurate royalty calculations.

14. Measurement Frequency and Methods

For reporting required by NTI-4A two forms must be filed: Form 9-329, the Monthly Report of Operation, and Form 9-361, the Monthly Report of Sales and Royalties. According to Title 30 CFR § 1210.102 (see footnote 589), all operators must file Form ONRR-4054 for each well for each calendar month, beginning the month in which drilling is completed unless it is only test production or ONRR grants an exemption on writing.

15. Engineering Estimates

According to NTI-4A, when there is no measurement, the volume of oil or gas must be determined utilizing the following criteria, as applicable:

- last measured throughout of the production facility
- duration of the period in which no measurement was made
- daily lease production rates
- historic production data
- well production rates and gas-to-oil ratio texts
- productive capability of other wells in the area completed in the same formation
- subsequent measurement or testing, as required by the supervisor
- other methods approved by the supervisor.

The 2016 GAO report (see footnote 591) considers these methods insufficiently specific, leading to varied methodologies across regions subject to the approval of the BLM regional supervisor. According to the report, some operators adopted estimation techniques used in the EPA's GHG reporting. The 2016 Waste Prevention Rule had more prescriptive requirements on measurement and estimation of flared and vent volumes (Title 43 § 3179.30), but the courts vacated Subpart 3179 in 2020. President Biden's Executive Order in early 2021 may lead the BLM to reinstate the 2016 Waste Prevention Rule with some modifications to avoid legal challenges.

16. Record Keeping

No requirements for how long records must be kept could be identified. However, the BLM reviews operational records every one to four years, depending on the lease conditions and performance.

17. Data Compilation and Publishing

The ONRR is responsible for compiling the OGOR databases, which include flare and vent volumes as well as emissions. Given the concerns expressed in the 2016 GAO report regarding the lack of specificity of the guidance for the OGOR reporting process, these data may not be consistent or complete.

Data on flared and vented volumes, aggregated by region, are available online from the Energy Information Administration (see footnote 593). They are based on voluntary summary reports from states, which, in turn, depend on self-reporting by producers. Not all states collect or report flaring and venting data to the Energy Information Administration. Those that do report do not necessarily follow the same reporting standards. Hence this data set is incomplete, and there are inconsistencies between state data and data published online by the Energy Information Administration. Section 17 of the previous chapter cites other national data sources.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

According to Title 43 CFR § 3163.1, in the event of failure or refusal to comply with BLM regulations, the terms of any lease or permit, any notice, or order requirements, the regulator notifies the party concerned in writing of the violation. A fine of US$1,000 per violation a day for major violations and a fine of US$250 per violation a day for minor violations may be imposed. According to Title 43 CFR § 3163.2, for failure or refusal to comply within 20 days (or another time period set by an authorized officer of the BLM) of the violation notice, the operator is liable for a civil penalty, which can be as high as US$5,000 per violation a day for up to 60 days.

19. Nonmonetary Penalties

According to Title 43 CFR § 3163.1, when necessary for compliance, or where operations have been commenced without approval, or where continued operations could result in immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income, the regulator may shut down operations after due written notice. Immediate shut-in in a possible if a BLM regional supervisor deems the offense severe enough. Continued noncompliance may lead to lease cancellation. According to Title 43 CFR § 3163.2, in addition to civil penalties, there can be criminal penalties of up to two years of imprisonment.

G. Enabling Framework

20. Performance Requirements

Section 20 of the previous chapter covers national environmental regulations with performance requirements applicable to flares. For onshore operations, Title 43 CFR § 3179.305 requires operators to find and repair leaks at least twice a year. The BLM is responsible for ensuring compliance with this regulation. However, a court vacated Subpart 3179 in 2020. One of the litigants' concerns was that the cost of adding equipment for leak detection would be too high for many small operators. President Biden's Executive Order in early 2021 may lead the BLM to reinstate the 2016 Waste Prevention Rule, with some modifications. For onshore operations, Title 43 CFR § 3179.305 requires operators to find and repair leaks at least twice a year. The BLM is responsible for ensuring compliance with this regulation. However, a court vacated Subpart 3179 in 2020. One of the litigants' concerns was that the cost of adding equipment for leak detection would be too high for many small operators. President Biden’s Executive Order in early 2021 may lead the BLM to reinstate the 2016 Waste Prevention Rule, with some modifications.
United States: Federal Onshore

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted. See section 22 of the chapter on the United States: Federal Offshore.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
For a description of the US natural gas market and infrastructure development, see section 24 of the chapter on the United States: Federal Offshore. For onshore operations, the BLM’s proposed waste minimization plan (see section 11 of this chapter) was intended to guide operators to work with midstream companies to identify sufficient pipeline and processing capacity near the planned drilling site so that associated gas can be captured from the first day of production. The previous US administration rescinded this requirement. The current one may reintroduce it or something similar.

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No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
For a description of the US natural gas market and infrastructure development, see section 24 of the chapter on the United States: Federal Offshore. For onshore operations, the BLM’s proposed waste minimization plan (see section 11 of this chapter) was intended to guide operators to work with midstream companies to identify sufficient pipeline and processing capacity near the planned drilling site so that associated gas can be captured from the first day of production. The previous US administration rescinded this requirement. The current one may reintroduce it or something similar.

United States: Colorado

A. Policy and Targets
1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives
Colorado has one of the lowest flaring rates among the oil-producing states. Through House Bill 19-1261,634 it committed to reducing its GHG emissions to 26 percent below 2005 levels by 2025, 50 percent below 2005 levels by 2030, and 90 percent below 2005 levels by 2050. Senate Bill 19-1818 aims to prevent the escape of natural gas into the air through flaring or venting and to minimize adverse impacts on public health and the environment from oil and gas operations. Governor Jared Polis signed both pieces of legislation into law in 2019. The state endorsed the World Bank’s Zero Routine Flaring by 2030 initiative in early 2021 (World Bank, n.d.; see footnote 3). Section 1 of the previous chapter provides federal information relevant to Colorado’s onshore oil and gas operations.

2. Targets and Limits
Colorado’s Greenhouse Gas Pollution Reduction Roadmap contains near-term and long-term targets, including for oil and gas sector. Implementation of new rules to eliminate routine flaring and venting is mentioned as a near-term goal.

B. Legal/Regulatory Framework and Contractual Rights
3. Primary and Secondary Legislation and Regulation
The Colorado Oil and Gas Conservation Act, 1951,635 defines the regulatory and enforcement authority for the state. Section 3 of the previous chapter provides relevant federal laws and regulations that apply to federal lands in Colorado. The Environmental Impact Prevention 900 Series, 2021,636 is Colorado’s central state-level regulation on flaring and venting. The Safety and Facility Operations Regulations 600 Series, 2021,637 regulate the siting requirements for all oil and gas industry–related facilities, including flare pits. The Rules of Practice and Procedure 500 Series, 2021,638 govern hearings, including enforcement hearings. Combined with § 3-60-127, Colorado Law, Colorado Revised Statutes, 2017,639 these rules allow disciplinary action to be taken.

The Colorado Air Pollution Prevention and Control Act, 1984,640 includes key aspects affecting climate change, air quality, and federal air quality standards. Regulation Number 1 Emission Control for Particulate Matter, Smoke, Carbon Monoxide, and Sulfur Oxides. 5 CCR 1001-3, 2020,641 covers requirements for atmospheric emissions from combustion devices. Regulation Number 3 Stationary Source Permitting and Air Pollutant Emission Notice Requirements 5 CCR 1001-5, 2020,642 represents the primary reporting and permitting regulation and encompasses the permitting aspects of flaring and venting. Regulation Number 7, Control of Ogone Via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides). 5 CCR 1001-9, 2009,643 governs the operation of oil and gas equipment, including requirements for gas capturing and combustion equipment.

4. Legislative Jurisdictions
Flaring and venting are matters for both national and state-level agencies. The BLM regulates flaring and venting on lands owned by the federal government and on lands owned by or held in trust for Native American tribes and individual tribal members within the boundaries of federally recognized reservations. State regulations apply to oil lands, including those that belong to the federal government, except for lands owned by Native American tribes and individual Native American entities.
5. Associated Gas Ownership

Land ownership determines mineral rights. About 36 percent of land in Colorado is federal land. Private landowners with surface rights own the rights to mineral resources under their land unless mineral rights are severed from surface rights (via a separate sale, for example). Companies can obtain a concession from the mineral rights owner to explore for oil and gas. In case of a commercial discovery, the concessionaire owns oil and gas under the leased area. Under most private leases, royalties are not paid on lost gas, which includes flared and vented volumes.

6. Regulatory Authority

Based on the Colorado Oil and Gas Conservation Act, 1951, the Colorado Oil and Gas Conservation Commission (COGCC) has the authority to regulate and enforce the development and production of the state’s oil and gas resources in a manner that protects public health, safety, welfare, the environment, and wildlife resources. As per the Colorado Air Pollution Prevention and Control Act, 1984 (see footnote 634), the Air Quality and Control Commission (AQCC) oversees the state’s air quality standards and minimize emissions from the oil and gas sector. The key powers assigned to it cover instruments such as permitting, compliance, and record-keeping.

7. Regulatory Mandates and Responsibilities

Both the COGCC and the AQCC have overlapping and shared authority over flaring and venting. For areas of joint interest between the COGCC and AQCC, particularly the protection of public health, an energy liaison officer from the Department of Public Health is assigned to coordinate alignment.

The COGCC is the primary regulator of flaring and venting because of its direct authority to prevent natural gas waste and protect public health. Rule 903 of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630) prohibits routine flaring and venting. It also includes record-keeping and reporting requirements to ensure that oil and gas operators comply with the rule’s prohibition of flaring and venting. The COGCC can impose penalties and otherwise require operators to take corrective action if the operator violates any part of Rule 903.

The AQCC also regulates flaring and venting as part of its statutory duty to ensure compliance with federal ambient air quality standards and minimize emissions from the oil and gas sector. The key powers assigned to it cover instruments such as permitting, compliance, and record-keeping.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

During drilling operations, Rule 903.b of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630) allows emergency flaring without prior notice when necessary to protect the safety of onsite personnel. However, a verbal notification must be provided to the COGCC within 12 hours of the event, and a written report must be submitted within 7 days.

10. Authorized Flaring or Venting

Rule 903.c requires operators to use reduced emission completion practices and enclose all flowback vessels to limit venting during completion operations. Flaring is allowed only with prior approval of the COGCC through a gas capture plan. Flaring is also allowed for a period not exceeding 24 hours during completion operations or for safety reasons during an upset condition.

Rule 903.d states that flaring or venting is prohibited during production operations unless one of the following exceptions applies:

- Flaring or venting lasting less than 24 hours is allowed during an upset condition. Operators must maintain records of the date, cause, duration, and estimated volume of gas vented or flared during each upset condition.
- Venting is allowed during active and required maintenance if it is in line with AQCC requirements, as long as the operator uses best practices to minimize venting during the maintenance or repair activity.
- Flaring lasting less than 24 hours can be allowed for safety considerations in the event of liquids unloading.
- For production evaluation and productivity testing purposes, flaring is allowed for up to 60 days, provided an approved gas capture plan is in place (see the next section).
- Flaring is allowed during wellhead pressure tests.

If the gas release had not been authorized, Rule 912 requires the operator to notify the director of the COGCC within 24 hours and then produce additional data on the incident within 10 days of the event. In case of the intended flaring of hydrogen sulfide, Rule 612 of the Safety and Facility Operations Regulations 600 Series, 2021 (see footnote 631) requires the operator to submit an air monitoring plan to the director of the COGCC before flaring.

11. Development Plans

Flaring approval during completion can be granted through an approved gas capture plan during the permitting process or a subsequent application explaining why flaring is necessary. The plan must detail how the operator will minimize adverse impacts and include information on the volume of gas that will be flared and the duration of flaring.

All proposed new facilities must submit a gas capture plan as part of their permit application, in accordance with Rule 903.e. The gas capture plan must include a commitment to connect the production facility to a gathering line before production starts or a plan for how the operator will connect the facility to a gathering line or otherwise put natural gas to beneficial use. If the gas capture plan is not implemented, the director of the COGCC may require the well to be shut in until there is an acceptable gas capture plan.

For wells completed before January 15, 2021, that are not connected to a gas gathering system or otherwise do not put natural gas to beneficial use, a formal application for permission to flare, including a gas capture plan, must be made. The director of the COGCC can approve the application once for up to 12 months, but in no case will such wells be allowed to flare or vent natural gas after January 15, 2022.

According to Rule 904 of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630), starting in 2022, the director of the COGCC will carry out an annual EIA of the cumulative impact of flaring and venting on key environmental metrics. Operators can be required to contribute as a condition of their development plans receiving approval.
United States: Colorado

12. Economic Evaluation
If the required gathering infrastructure (as discussed in the previous section) is unlikely to be available, an operator may either shut in the well or make a formal variance request to COGCC under Rule 502 of The Rules of Practice and Procedure 500 Series, 2021 [see footnote 632]. A formal variance request requires the operator to prove in a formal hearing that it would suffer undue economic hardship and that there will be no net adverse impacts from continued flaring or venting.

13. Engineering Estimates
Under Rule 903(d) of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630), gas flared or vented needs to be metered subject to the requirements of Rules 429 and 430 of the Operations and Reporting 400 Series, 2021 [see footnote 632] or estimated and reported on a per-well basis in the operator’s monthly operations report as required by Rule 413.

14. Measurement Frequency and Methods
According to Rule 903(d) of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630), the metered or estimated gas flared or vented during production operations must be reported monthly.

15. Record Keeping
According to Rule 903 of the Environmental Impact Prevention 900 Series, 2021, the operator needs to maintain flaring and venting data records. Rule 206 of the General Provisions 200 Series, 2021 [see footnote 632] requires operators to keep all records for five years and provide access to the director or the COGCC upon request (see sections 10 and 14 of this chapter).

16. Data Compilation and Publishing
At the state level, the COGCC publishes oil- and gas-related data on its website. The Energy Information Administration compiles data from states and reports on its website, but the data are incomplete (see section 17 of the chapter on the United States: Federal Onshore).

17. Fines, Penalties, and Sanctions

18. Monetary Penalties
According to § 34–60–121, Colorado Law, Colorado Revised Statutes, 2017 (see footnote 632), and Rule 525 of The Rules of Practice and Procedure 500 Series, 2021 (see footnote 632), the COGCC has powers to impose penalties on operators violating its rules, orders, or permits. The penalties depend on the duration and severity of the adverse consequences on public health, safety, or the environment. However, penalties are limited to US$15,000 a day of violation. Higher penalties are possible for behaviors such as gross negligence and willful misconduct, noncooperation of the operator, significant loss of resources, and falsified reports. Mitigating factors include self-reporting or prompt and prudent responses by the operator.

19. Nonmonetary Penalties
Rule 901 of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630), empowers the director of the COGCC to suspend operations or initiate immediate mitigation measures until the cause of the threat to public health, safety, welfare, the environment, or wildlife resources is identified and mitigated. Rule 210 of the General Provisions 200 Series, 2021 (see footnote 641) and Rule 525 of The Rules of Practice and Procedure 500 Series, 2021 (see footnote 632) also empower the COGCC to issue corrective actions to stop an adverse event. Rule 209(a) of the General Provisions 200 Series, 2021, empowers the director of the COGCC to require an operator to conduct tests or surveys, if necessary and reasonable, to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources.

Under § 34–60–121(2), Colorado Law, Colorado Revised Statutes, 2017 (see footnote 633), individual employees of an operator that intentionally make a false report to the COGCC may also be subject to criminal prosecution. If found guilty, an employee may be fined up to US$5,000 or sentenced to up to six months of imprisonment.

20. Performance Requirements
Rule 903 of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630) requires a 98 percent design efficiency for the combustion of flare gas. This requirement is in line with the EPA’s national legislation (see section 20 of the chapter on the United States: Federal Offshore).

21. Fiscal and Emission Reduction Incentives
No evidence regarding fiscal or emission reduction incentives could be found in the sources consulted.

22. Use of Market-Based Principles
No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions in Colorado could be found in the sources consulted (but see section 22 of the chapter on the United States: Federal Offshore).

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
The intention of the gas capture plan mentioned in Rule 903(e) of the Environmental Impact Prevention 900 Series, 2021 (see footnote 630) is to ensure the beneficial use of the gas in the future. In areas with a limited pipeline network, the beneficial use requirement has led to solutions for gas that would otherwise have been flared. See section 24 of the chapter on the United States: Federal Onshore.

United States: North Dakota

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Both federal and state policy regulate flaring and venting in North Dakota. Because of increased drilling activity in the Bakken play, the volume of gas flared has increased rapidly and substantially, according to data provided by the Energy Information Administration. The total volume increased from 10 bcf in 2007 to 205 bcf in 2019; flare intensity has exceeded 300 cubic feet (cf) of associated gas per barrel of oil produced since the late 2000s, reaching 400 cf per barrel in 2019. The only exception occurred during the low oil price period of 2015–17, when the flare intensity averaged 220 cf per barrel.

The state put gas capture rules in place in 2014 to reduce the amount of flaring allowed from 26 percent to 12 percent of total associated gas produced by 2020 and 9 percent after 2020. About US$1 billion had been invested in infrastructure by 2016, and the gas capture rate reached 85 percent. However, during the oil price downturn, there was virtually no spending on gas capture infrastructure; operators focused on drilling in the Bakken’s core area, where wells produce more gas. Oil production bounced back quickly in 2018, exceeding takeaway infrastructure, and the gas capture rate declined until 2020, when the state reported a gas capture rate of 92 percent, largely as a result of decreased associated gas produced by 2020 and 9 percent after 2020.

2. Targets and Limits

In the early 2010s, the North Dakota Petroleum Council’s Flaring Task Force targeted capturing 74 percent of associated gas in 2014, gradually increasing to 90 percent by late 2020; it proposed 95 percent as a potential target beyond 2020. The North Dakota Industrial Commission (NDIC)’s Order 24665, 2014, operationalized these targets, raising the 2020 target to 91 percent in 2018.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

North Dakota Administrative Code (NDAC) Chapter 43-02-02-03 provides guidance on oil and gas conservation. NDAC Section 43-02-03-45 bans venting and requires casinghead gas to be flared, with the estimated volume reported to the director of the oil and gas division of the North Dakota Department of Mineral Resources. Section 38-08-06-4 of North Dakota Century Code Chapter 38 declares gas flaring as restricted and describes the conditions under which an operator can flare. Order 24665, 2014, introduces restrictions on flaring that strive to meet the North Dakota Petroleum Council’s Flaring Task Force targets (see the previous section) and outlines requirements for obtaining exemptions for flaring and penalties for noncompliance with regulations and permit conditions. Federal and tribal policies apply to federal and Indian lands.

Sections 33.1-15-20-02 and 33.1-15-20-04 of NDAC Chapter 33.1-15-20: Control of Emissions from Oil and Gas Well Production Facilities require all oil and gas wells within the state to be registered with the North Dakota Department of Environmental Quality’s Division of Air Quality (DAQ) and adhere to emission controls. Section 33.1-15-03-01 of NDAC Article 33.1-15-03: Restiction of Emission of Visible Air Contaminants mentions restrictions applicable to flares. Section 33.1-15-07-02 of NDAC Article 33.1-15-07: Control of Organic Compounds Emissions prohibits the emission of organic compounds in gaseous and vapor forms except in emergencies unless they are burned in flares or controlled otherwise.

4. Legislative Jurisdictions

Flaring and venting in North Dakota are subject to both state and federal jurisdiction because a large share of production in the state comes from federal and tribal lands. The BLM and North Dakota Field Office manages about 2,500 leases on federal lands and has trust responsibility for more than 3,000 leases on Indian lands. Tribal authorities may have jurisdiction in some situations. With respect to air emissions, the EPA plays a role by approving SIPs.

5. Associated Gas Ownership

Land ownership determines mineral rights. About 10 percent of land in North Dakota is federal or Indian land, where the respective government owners own subsurface oil and gas. The Fort Berthold Reservation encompasses more than 1 million acres and the two most-drilled oil formations, the Bakken and the Three Forks. Many reservoirs are also within the jurisdiction of the Mandan Hidatasa and Arikara Nation. In the rest of the state, private landowners own the rights to mineral resources under their land. In some cases, mineral rights may be severed from surface rights but are held privately. Companies own a concession from the mineral rights owner to explore for oil and gas. In case of a commercial discovery, the concessionaire owns oil and gas under the leased area. Under most private leases, royalties are not paid on lost gas, which includes flared and vented volumes.

C. Regulatory Governance and Organization

6. Regulatory Authority

The Oil and Gas Division of the North Dakota Department of Mineral Resources regulates the drilling and production of oil and gas in the state (including drilling permits and gas capture plans), but the NDIC has jurisdiction over flaring and venting. DAQ (see footnote 653), regulates emissions from upstream, midstream, and downstream oil and gas operations. The BLM and the EPA, and, in some cases, tribal authorities have authority over oil and gas operations on federal and Indian lands.

7. Regulatory Mandates and Responsibilities

The NDIC regulates the volume of gas flared at a well site under its mandate to conserve mineral resources (NDAC 43-02-03-03). DAQ regulates emissions from flares. DAQ’s remit includes when gas should be flared, the permissible types of flaring, and proper flare plan), but the NDIC has jurisdiction over flaring and venting. DAQ (see footnote 653), regulates emissions from upstream, midstream, and downstream oil and gas operations. The BLM and the EPA, and, in some cases, tribal authorities have authority over oil and gas operations on federal and Indian lands.

8. Monitoring and Enforcement

Under NDAC 43-02-03-14, the NDIC, or its representatives, can access all sites and records across all oil and gas operations. DAQ has the authority to inspect oil and gas sites to ensure compliance with its air permits and the proper functioning of emission control equipment. Both the NDIC and DAQ can enforce compliance using monetary and nonmonetary penalties. Nevertheless, regulators have struggled to ensure compliance, mainly because of a shortage of midstream capacity but also because of problems at well sites. In October 2020, for example, DAQ issued a compliance alert with respect to air emissions from oil and gas operations. The alert listed several problems with flare equipment and leaks from various equipment as key concerns.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

North Dakota Century Code Section 38-08-06-4 (see footnote 651), allows gas flaring from oil wells up to one year from first production.

The venting of casinghead gas is not allowed under any circumstances; instead, operators must have equipment in place to flare.
United States: North Dakota

10. Authorized Flaring or Venting

According to North Dakota Century Code Section 38-08-06.4, after the first year of production, flaring must cease. The operator can cap the well, connect it to a gathering system, increase the use of associated gas, or use the gas in any other beneficial action approved by the NDIC. Operators may apply for a flaring exemption if the connection of a well to a natural gas gathering line is economically infeasible.

DAQ has an independent permit application for flares associated with air quality and the control of pollutants659 for oil or gas production facilities classified as a major stationary source or a major modification.

11. Development Plans

Order 24665, 2014, requires upstream operators to submit a gas capture plan with every drilling permit application to the NDIC. Gas capture plans must include information on area gathering system connections and processing plants, the rate and duration of planned flowback, current system capacity, and a timeline for connecting the well. They must also include a signed affidavit verifying that the plan has been shared with area midstream companies.

The NDIC allows production from horizontal wells in Bakken and Three Forks Pools for up to 90 days (one year in noncore areas) at the maximum efficiency rate irrespective of flaring volumes. After 90 days, the operator should either meet gas capture goals or limit production. NDIC Order 24665, 2014 (see footnote 649) provides flexibility in the form of temporary exemptions from production restrictions for up to one year if an operator files a request and provides the necessary documentation. The NDIC may consider further flexibility under other extenuating circumstances after notifying the operator and hearing whether the exemption is expected to result in a significant net increase in gas capture within a year. The NDIC has also implemented a gas capture credit system (see section 22 of this chapter).

12. Economic Evaluation

According to Order 24665, 2014 (see footnote 648), well payouts and economics should not be used to determine the production restrictions imposed on operators that do not comply with gas capture plans. At the same time, the order allows for the maximum efficient rate of oil production in many circumstances. The NDIC tries to distinguish between operators that are connected to gathering systems but flare and those that flare because of midstream bottlenecks. Over the years, the NDIC policy and regulation have shifted toward encouraging investment in midstream infrastructure. Nevertheless, the comparison of the value of oil and the value of associated gas if captured remains central to operators’ decisions to invest in capture infrastructure and the NDIC’s assessment of drilling applications and flaring exemptions.

13. Measurement and Reporting Requirements

NDAC Section 43-02-03-52 requires reporting of the amounts of gas associated with oil wells from the first day of production, including flowback and production test gas and flared volumes, using Gas Production Report Form 5B.660 NDAC Section 43-02-03-44 mandates all measurement equipment and volume determination used for reporting casinghead gas to be compliant with American Gas Association standards.

DAQ requires operators to submit an incinerators or Flares Annual Emission Inventory Report661. Oil and gas operators may be responsible for submitting additional environmental reports to both DAQ and the EPA.662 Operators must use air quality models or formulas included in different chapters of NDAC Article 33.1-15 while reporting air emissions data.

14. Measurement Frequency and Methods

Per NDAC Section 43-02-03-52.1, Form SB must be reported monthly or on or before the fifth day of the second month after the gas was produced. In November 2018, North Dakota loosened flared gas reporting regulations, allowing producers the option of excluding particular well sites that fall under certain criteria from their reporting.

15. Engineering Estimates

Per NDAC Section 43-02-03-52.1 Form SB requires an accounting equivalency. Gas produced minus lease-use gas minus flared gas must equal wet gas transferred. Certain sections of NDAC Article 33.1-15 include formulas to use when calculating emissions.

16. Record Keeping

NDAC Section 43-02-03-85 requires all oil and gas to keep records on all of their operations covered under NDAC Chapter 43-02-03 for at least six years.

17. Data Compilation and Publishing

Flared gas volumes are reported by the North Dakota Department of Mineral Resources along with other production data.663 The Energy Information Administration compiles data from states and reports on its website, but the data are incomplete (see section 17 of the chapter on United States: Federal Onshore).

18. Fines, Penalties, and Sanctions

According to North Dakota Century Code Section 38-08-06.4, violators of flaring exemptions will pay production taxes and royalties on flared gas. NDIC Order 24665, 2014 (see footnote 647) outlines penalties the NDIC may impose on operators for failing to comply with gas capture goals. Penalties start at US$1,000 for each violation and increase up to US$12,500 for each offense. Each day’s violation is a separate offense.

19. Nonmonetary Penalties

Operators of oil wells that do not report associated gas volumes by the due date (see section 13 of this chapter) may be shut in for up to 30 days. If operators continue to produce gas during the shut-in period, they will be subject to penalties. North Dakota Century Code Section 38-08-16 states that a person who willfully violates any rule or order of the commission that pertains to the prevention or control of pollution or waste is guilty of a Class C felony. A court of competent jurisdiction may impose a criminal penalty.

20. Performance Requirements

The NDIC regulations are designed to provide operators maximum flexibility to manage their drilling, operation, and gas capture plans within the gas capture goals (see footnote 647). The standards are applied state-wide, then at the county level, field level, and well level. The enforcement mechanism provides that if the operator cannot attain the capture goals at the maximum efficiency rate, wells will be restricted to 200 barrels of oil a day if at least 60 percent of the monthly volume of associated gas produced from the well is captured. Otherwise, oil production from such wells should not exceed 100 barrels of oil a day. Because of the unique properties of the geologic formations in Bakken, DAQ has developed guidelines and regulations related to the air quality requirements of facilities producing and processing oil and gas from these formations.664 More efficient pollution control is required for tanks located on sites where the emissions of volatile organic compounds from tanks are greater than 20
United States: North Dakota

tonnes a year, and such controls must be in place and operational within 60 days of production starting.

Companies need to meet certain performance requirements to qualify for a DAQ air permit (see section 10 of this chapter). NDAC Section 33.1-15-20, 2019, focuses on preventing significant deterioration of air quality as a result of emissions from oil and gas well production facilities and refers to many other sections of Chapter 33.1-15 on Air Pollution Control. NDAC Section 33.1-15-20, 2019, provides a formula to calculate emissions, which should meet ambient air quality standards as outlined in NDAC Section 33.1-15-02, 2019. Flares must have automatic ignitors or continuously burning pilots, and the flare stack must be tall enough for adequate dispersion of emissions. NDAC Section 33.1-15-07, 2019, bars the release of organic compounds in gaseous and vapor forms except in emergencies or when flared or combusted in another effective control device approved by the NDIC. NDAC Section 33.1-15-03, 2019, restricts the opacity of emissions from flares.

According to DAQ, equipment at oil and gas facilities in North Dakota may be subject to Title 40 CFR § 60 and § 63.665 Flares must have automatic ignitors or continuously burning pilots, and the flare stack must be tall enough for adequate dispersion of emissions. NDAC Section 33.1-15-07, 2019, bars the release of organic compounds in gaseous and vapor forms except in emergencies or when flared or combusted in another effective control device approved by the NDIC. NDAC Section 33.1-15-03, 2019, restricts the opacity of emissions from flares. 665  https://www.legis.nd.gov/information/acdata/pdf/33.1-15-02.pdf (accessed August 15, 2021).

22. Use of Market-Based Principles

Per NDIC Order 24665, 2014, an operator is allowed to accumulate credits for LNG utilization, CNG utilization, and volumes of gas captured during the most recent six months in excess of the current gas capture goal. The NDIC grants the use of credits to meet monthly gas capture target only under certain circumstances: right-of-way issues, midstream outages, federal regulations, safety issues, delayed access to electricity, and possible reservoir damage. Credits cannot be transferred to another operator. Unused credits expire after six months. Most transportation contracts are for interruptible service, which means a producer may be denied the ability to transport natural gas in a gathering system if the system is constrained, such as when a shortage of processing capacity causes downstream bottlenecks. In November 2019, the NDIC issued an order that is, interruptible) service agreements, which would guarantee access to pipelines.

23. Negotiated Agreements between the Public and the Private Sector

The North Dakota Oil and Gas Research Program,670 an NDIC initiative, is a joint state and industry effort established in 2003 that supports research into oil and natural gas exploration and production. Recent projects include efforts to develop methods for reducing flaring through small-scale gas-to-liquids, CNG, LNG, and electricity generation.

United States: Texas

A. Policy and Targets

1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Flaring and venting have been regulated in Texas for decades, but flare volumes soared, from about 35 bcf in 2011 to 251 bcf in 2019, according to data from the Energy Information Administration. The increase reflected a ramp-up in drilling activity in the Permian, Eagle Ford, and other plays and the inability of the midstream gas infrastructure to grow in parallel with associated gas production. The Permian Methane Analytics Project found that about 11 percent of Permian flares surveyed were either unlit or malfunctioning.

In response, the state oil and gas regulator, the Railroad Commission (RRC), revised its reporting requirements. The RRC’s number of authorizations for flaring and venting increased from 107 in 2008 to 6,972 in 2019 (see footnote 682). The rise in flare permitting has been steady, except in 2016 and 2017, when the global oil price slumped. The industry is trying to improve its performance, but the lack of gas pipeline and processing capacity remains the leading cause of continued flaring. According to data from the Energy Information Administration, Texas has flared 70–90 cf per barrel of oil produced since the 1990s, but its flaring intensity doubled to 140–150 cf per barrel in 2018 and 2019. Pressure on the RRC and the oil and gas industry to end routine flaring is increasing from various quarters, including investors, environmental groups, and other civic organizations in Texas and elsewhere. Although they were eventually abandoned, the Texas Legislature considered two bills on emissions and flaring by the oil and gas industry in early 2021.

2. Targets and Limits

There is a 10-day limit on flaring during drilling and well testing. Once testing is over, the RRC can authorize further flaring up to 180 days. Operators may release low pressure separator hydrocarbons, up to 15 mcf a day from a gas well or 50 mcf a day, from an oil lease or commingling point for commingled operations (see sections 9 and 10 of this chapter).

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

The Texas Natural Resources Code’s Chapter 85 declares the waste of oil and gas resources “illegal and prohibited.” With respect to flaring, the RRC implements this clause using Texas Administrative Code, Title 16, Part 1, Section 3.32, known as Statewide Rule 32. The rule outlines the conditions under which flaring may be allowed. In response to increased flaring volumes and public scrutiny, the RRC published a new Application for Exception to Statewide Rule 32 in late 2020 but did not change the rule (see section 10 of this chapter).

The Texas Air Quality SIP was adopted in 2004 and approved by the EPA in 2006. Texas’ SIP Vent Gas Control program (Sections 720–729 of Chapter 151, entitled “Control of Air Pollution from Volatile Organic Compounds”) is most relevant for oil and gas operations. There is also a GHG permitting program at the Texas Commission on Environmental Quality (TCEQ) but it focuses primarily on power plants based on the EPA’s GHG program under the Clean Air Act, 1990.

4. Legislative Jurisdictions

Flaring and venting in Texas are primarily state matters; federal onshore regulations are largely irrelevant in Texas. The share of producible completions in Texas out of total producible completions across all federal lands approved by the BLM was about 0.5 percent through the 2010s. With respect to air emissions, the EPA plays a role by approving SIPs.

5. Associated Gas Ownership

Land ownership determines mineral rights. About 12 percent of Texas is public land managed by the General Land Office. Revenue from mineral resources developed on these lands is used for public education. Federal lands account for only about 1 percent of all land in Texas. In the rest of the state, private landowners own the rights to mineral resources under their land. In some cases, mineral rights may be severed from surface rights but are still held privately. Companies obtain a concession from the mineral rights owner to explore for oil and gas. In the case of a commercial discovery, the concessionaire owns oil and gas under the leased area. Under most private leases, royalties are not paid on last gas, which includes flared and vented volumes.

C. Regulatory Governance and Organization

6. Regulatory Authority

The RRC regulates the exploration, production, and transportation of the oil and gas industry. The TCEQ regulates air emissions.

7. Regulatory Mandates and Responsibilities

The RRC has jurisdiction over the permitting of flaring operations with respect to preventing the waste of natural resources. The TCEQ is charged with reviewing and approving air pollution permits for industrial and commercial sources, including flaring and venting.

8. Monitoring and Enforcement

The RRC’s inspectors (usually housed in district offices closer to operations) can visit sites “to witness operations, conduct inspections, provide information about permitting requirements, and ensure compliance with permits issued by the Commission” (see footnote 680). The RRC has used a light-touch approach to regulating flaring from oil and gas activity. State policy and regulation have focused on economic development and job creation. With 12 percent of Texas being public lands, revenues from mineral extraction are important, but they are not appointed but are elected, creating an inherent tension between the regulator’s duties to protect the environment and to steward the efficient development of mineral resources and environmental protection. Separately, per SIP, the TCEQ is expected to conduct inspections at least quarterly to ensure the proper operation of continuous monitoring systems and pressure valves.

D. Licensing/Process Approval

9. A Flaring or Venting without Prior Approval

Statewide Rule 32 (see footnote 678) allows operators to flare oil-well gas while drilling a new well and testing the well for up to 10 days. Venting is allowed for releases lasting less than 24 hours, unless flaring is necessary for safety reasons; operators are encouraged to verify with RRC District Offices whether they can vent or must flare. Gas that must be unloaded from a well may be vented for up to 24 hours in one continuous event or up to 72 cumulative hours in one month.

10. Authorized Flaring or Venting

Statewide Rule 32 allows operators to flare oil-well gas beyond the initial 10 days with an exception to Rule 32 issued by the RRC. Typically, exceptions are not granted for flaring from gas wells. Flaring exceptions are granted for 45 days at a time for up to 180 days. More documentation is required every time an operator applies for an extension. Exceptions beyond 180 days must be approved by an RRC Final Order after a hearing. An exception may be approved administratively and indefinitely if flaring is less than 50 mcf a day at an oil well and 15 mcf a day at a gas well.
According to the RRC, most exceptions are for flaring casinghead gas from oil wells. Flaring could be necessary for extended periods if the well is drilled in new exploration areas without sufficient gas pipeline or processing capacity. Other acceptable reasons include processing plant shutdowns and repairs or maintenance at production or pipeline facilities such as compressors (see footnote 682).

Separately, operators should apply for standard air permits from the TCEQ if activities (such as flaring) are considered “routine events.” The TCEQ provides guidelines for standard air permits. These permits do not authorize emissions from upsets, emergencies, or malfunctions. They cover volatile organic compounds, particulate matter, and oxides of nitrogen but do not cover methane and carbon dioxide.

11. Development Plans
No evidence regarding development plans could be found in the sources consulted.

12. Economic Evaluation
In late 2020, the RRC updated Statewide Rule 32 Exception Data Sheet (Form R-32), used by operators to apply for flaring exceptions. After collecting comments from stakeholders on a draft, it published a new version, entitled "Application for Exception to Statewide Rule 32." The new form requires operators to include technical and economic justifications with the goal of reducing the duration of flaring exceptions. This specific information enables the RRC to assess compliance by identifying and tracking the location of flares and vent points. The documentation required includes a cost–benefit analysis, a map showing the nearest pipeline capable of accepting gas, and an estimate of gas reserves. In most cases, the changes are expected to reduce the time an operator may obtain an administrative exception to flare by 50–80 percent.687

E. Measurement and Reporting

13. Measurement and Reporting Requirements
Operators must report volumes of gas flared to the RRC using the monthly production report (Form PR). This report must include metered gas volumes from both gas wells and casinghead gas from oil wells at the lease level (see footnote 682). The RRC updated instructions for completing Form PR and instructed operators to report flaring and venting separately and remark on the status of the RRC exception for each flaring or venting event.688 The RRC is also developing an online system for the flare and vent program. This system will include information on permitting, data analysis, and compliance.

Texas SIP Vent Gas Control regulations (see footnote 679) require the operator of each affected flare or vent gas stream to adhere to reporting and record-keeping requirements, which include the development and implementation of a quality assurance plan for the monitoring requirements, including installation, calibration, operation, and maintenance of continuous emissions monitoring systems. Separately, operators must submit written notification to the regional office of the EPA at least 45 days before conducting any flare and vent gas stream testing, as required by Texas SIP.

14. Measurement Frequency and Methods
Operators must file Form PR Form monthly. Historically, flared and vented gas volumes were reported together in Form PR, but new RRC instructions require that operators report them separately starting in September 2021.

Texas SIP Vent Gas Control regulations require operators of affected flares to install an on-line analyzer system capable of determining highly reactive volatile organic compounds at least once every 15 minutes. The system must also measure other potential emissions—such as hydrogen, nitrogen, carbon dioxide, methane, and other volatile organic compounds—sufficient to determine the molecular weight and net heating value of the gas combusted in the flare to within 5 percent.

15. Engineering Estimates
Part 1, Section 3.27 of Texas Administrative Code, Title 16 (see footnote 678) details measurement requirements and standards for RRC Form PR reporting. According to Texas SIP Vent Gas Control regulations, the flow rate of the gas routed to the flare, in standard cubic feet per minute, must be determined by either complying with the monitoring requirements or using process knowledge and engineering calculations.

16. Record Keeping
No evidence regarding record-keeping requirements could be found in the sources consulted.

17. Data Compilation and Publishing
Data from RRC Form PR are available on the RRC website. These air emissions data are available in various formats. Several data sets include volatile organic compounds and point sources. The Energy Information Administration compiles data from states and reports on its website, but the data are incomplete (see section 17 of the chapter on the United States: Federal Onshore).

F. Fines, Penalties, and Sanctions

18. Monetary Penalties
Most violations, including the violation of flaring exceptions, are resolved through the RRC’s district offices by means other than administrative penalties. Nevertheless, the RRC has statutory authority to assess administrative penalties for violations related to safety, environmental, and other permits according to Texas Natural Resources Code Subsections 81.0531 through 81.0533. The RRC may assess up to USS10,000 a day per violation and USS500 a day for non-safety; or pollution-related violations.

Part 1, Section 3.107 of Texas Administrative Code, Title 16 (see footnote 678) provides guidelines on penalties for various types of oil and gas violations. The RRC considers the seriousness of the violation, the operator’s history of compliance, and other relevant factors to determine the amount of the penalty.

19. Nonmonetary Penalties
According to Subsections 91.701–91.707 of Texas Natural Resources Code, Title 3, the RRC may cancel a certificate of compliance after issuing a notice of violation to the operator. Once the certificate is canceled, operations must stop. The RRC can also modify, suspend, or terminate a permit if there is a violation (see footnote 692).

G. Enabling Framework

20. Performance Requirements
The TCEQ provides guidance on how flares must be designed and operated based on the specifications of Title 40 CFR § 60.18 (see footnote 600). Among other requirements, it requires flares to be always operated with a flame present or have a constant pilot flame, which should be continuously monitored by a thermocouple, infrared moniter, or ultraviolet monitor. There should be no visible emissions, except during periods not exceeding a total of five minutes during any two consecutive hours.

21. Fiscal and Emission Reduction Incentives
Part 1, Section 3.103 of Texas Administrative Code, Title 16 (see footnote 678) provides for an incentive to market flared or vented gas via an exemption from the state severance tax of 7.5 percent on the marketed gas volume for the life of the well. To qualify, such marketed gas should have previously been vented or flared for 12 months or more. However, this incentive is at least partially negated by Subtitle I, Section 201.053 of Texas Administrative Code, Title 3, which exempts oil–well gas that is lawfully vented or flared from the severance tax.
United States: Texas

22. Use of Market-Based Principles
The TCEQ operates several cap-and-trade programs, but they focus on urban air quality, mostly in Houston’s eastern Gulf Coast region. They do not capture volatile organic compounds from oil and gas operations in most of the state. There is no similar program for GHGs.

23. Negotiated Agreements between the Public and the Private Sector
No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework
The primary reason for flaring in the Permian Basin has been the lack of natural gas pipeline capacity to transport gas to markets. Several natural gas pipelines have been built or are under construction to transport gas to markets, including LNG facilities. In the meantime, because the impact of gas sales on overall well economics has been limited, the RRC appears unlikely to restrict oil production to reduce flaring. For example, in May 2020, the RRC rejected a proposal to cut oil production by 20 percent in a 2 to 1 vote. The split decision was based on the expectation that the issue would resolve itself once the necessary infrastructure was built. However, the RRC’s new requirement of more detailed economic justifications before approving flaring exceptions may change the current situation. As highlighted in the Texas Natural Resources Code, preventing the waste of the state’s natural resources is attracting attention.697

Some Permian Basin producers, mainly small ones, argue that delaying well completions or reducing oil production rates while waiting for sufficient gas takeaway capacity will lead to an immediate loss in income that far exceeds any future revenue increase from gas sales. Major producers in the Permian Basin treat gas takeaway capacity as a manageable constraint that involves ensuring that adequate takeaway infrastructure is in place before bringing a well online and being willing to shut in a well until takeaway capacity is secure. Ongoing consolidation among operators is reinforcing this trend.

Venezuela, República Bolivariana de

8.19 billion cubic meters of gas flared in 2021
(total oil production 589 thousand barrels per day)

A. Policy and Targets
1. Background and the Role of Reductions in Meeting Environmental and Economic Objectives

Between 2012 and 2021, the flaring intensity in the República Bolivariana de Venezuela increased by a factor of four—by far the largest increase in the countries studied. In 2021, its flaring intensity was 38.1 m³ per barrel of crude oil produced, the highest of all countries studied (figure 21). Despite a declining trend in oil production starting in 2018, which reduced 2021 production to about one-fifth the 2012 level, the volume of gas flared remains stable. There were 162 individual flare sites in the last flare count, conducted in 2019.

The country submitted its NDC to the UNFCCC in 2018. It includes a national mitigation plan that aims to reduce emissions by at least 20 percent by 2030 compared with a scenario in which the plan is not implemented. The NDC cites projects by the national oil company, Petróleos de Venezuela, S.A. (PDVSA), to reduce flaring and venting by implementing associated gas utilization projects. These projects are reported to reduce GHG emissions by more than 500,000 tCO₂e.

More than 90 percent of the gas produced in the República Bolivariana de Venezuela is associated with crude oil production. Most of the flared gas comes from mature fields in the eastern part of the country and the Orinoco Belt. The routine flaring of gas by PDVSA in northern Monagas has become one of the largest sources of natural gas flaring in the world.

2. Targets and Limits

No evidence regarding targets and limits could be found in the sources consulted.

B. Legal/Regulatory Framework and Contractual Rights

3. Primary and Secondary Legislation and Regulation

Article 2 of the Organic Law on Hydrocarbons, 2006, states that activities related to natural gas are governed by the Organic Law on Gaseous Hydrocarbons, 1999, except for the extraction of associated gas, which is governed by the Organic Law on Hydrocarbons, 2006. These laws allow for gas exploration and exploitation operations by third parties, without PDVSA intervention, but with the obligation to sell the gas to PDVSA or other state companies at prices set by the government. Article 2 of the Organic Law on Gaseous Hydrocarbons, 1999, governs the collection, storage, processing, industrialization, transport, distribution, and internal and external commercialization of nonassociated and associated gas.


4. Legislative Jurisdictions

Natural gas, including flared and vented gas, is a matter of national jurisdiction, as stated in Articles 1–3 of the Organic Law on Gaseous Hydrocarbons, 1999.

5. Associated Gas Ownership


Note: Data and figures provided in this report are based on flare data gathered by the Global Gas Flaring Reduction Partnership (GGFR), using satellite data from the Colorado School of Mines. This approach is applied to all countries covered in this report in a consistent manner.

Figure 21 Gas flaring volume and intensity in República Bolivariana de Venezuela, 2012–21

<table>
<thead>
<tr>
<th>Year</th>
<th>Flaring Intensity</th>
<th>Flaring Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>4.8</td>
<td>1.8</td>
</tr>
<tr>
<td>2013</td>
<td>5.4</td>
<td>2.1</td>
</tr>
<tr>
<td>2014</td>
<td>6.0</td>
<td>2.4</td>
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<tr>
<td>2015</td>
<td>6.6</td>
<td>2.7</td>
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<tr>
<td>2016</td>
<td>7.2</td>
<td>3.0</td>
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<tr>
<td>2017</td>
<td>7.8</td>
<td>3.3</td>
</tr>
<tr>
<td>2018</td>
<td>8.4</td>
<td>3.6</td>
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<tr>
<td>2019</td>
<td>9.0</td>
<td>3.9</td>
</tr>
<tr>
<td>2020</td>
<td>9.6</td>
<td>4.2</td>
</tr>
<tr>
<td>2021</td>
<td>10.2</td>
<td>4.5</td>
</tr>
</tbody>
</table>


References:

Venezuela, República Bolivariana de

in Article 20, the Ministry of Mines and Hydrocarbons (now the Ministry of Popular Power of Petroleum) may take it free of charge at the separator’s exit.

C. Regulatory Governance and Organization

6. Regulatory Authority

The Ministry of Popular Power of Petroleum701 (known as MinPetróleo) is the overarching policy and regulatory authority. The Ministry of Popular Power for Ecosocialism (Ministerio del Poder Popular para el Ecosocialismo [MINEC])707 is the environmental policy and regulatory authority.

7. Regulatory Mandates and Responsibilities

MinPetróleo is in charge of formulating, executing, and evaluating the country’s oil and gas policies and regulating the industry. It supervises and controls the operations of the PDVSA and its subsidiaries, which the government owns. MINEC regulates emissions from oil and gas operations and is responsible for authorizing flaring and venting. It provides permission to flare on a case-by-case basis, in accordance with Decree 638/1995708 (see footnote 680), which stipulates air quality limits and permitted maximum air emission levels for controlling atmospheric emissions, including from flaring. Article 20 of Decree 1257/1996709 requires operators to submit details of the composition of their emissions to MINEC at least annually.

8. Monitoring and Enforcement

Article 6 of the Organic Law on Gasous Hydrocarbons1999 (see footnote 707) and Articles 10, 14, and 16 of the Organic Law of the Environment, 2006,706 empower the regulator to monitor and audit the oil and gas operations for the protection of the environment.

D. Licensing/Process Approval

9. Flaring or Venting without Prior Approval

Article 121 of the Regulation of the Hydrocarbon Law, 1943 (see footnote 700) establishes that excess gas that cannot be used or returned to the field can be flared. Only gas from wells with very low pressure is allowed to be vented. Vents must be high enough to facilitate the dispersion of gas without causing harm.

Article 40 of Decree 638/1995 (see footnote 704) states that MINEC may authorize trial periods for the initial operation of processes or equipment to control emissions. This authorization is granted in accordance with Article 21 of the Organic Law of the Environment, 2006 (see footnote 707); its duration is limited to six months or less. In cases of emergency or unforeseeable emissions in violation of the regulations, the operator must notify MINEC and activate its emergency contingency plans.

10. Authorized Flaring or Venting

Articles 20–23 of Decree 1257/1996 (see footnote 708) require operators to obtain environmental licenses before starting exploration or production. Applicants must submit to MINEC an EIA that describes their gas flaring and venting activities. After evaluation, MINEC may grant an environmental license for such activities. The license may contain specific requirements and emission reporting procedures for flaring and venting, which are set on a case-by-case basis. In addition, Decree 638/1995 (see footnote 704) requires a specific flaring permit to be sought from MINEC during operations.

11. Development Plans

No evidence regarding development plans could be found in the sources consulted.

12. Economic Evaluation

Article 20 of the Regulation for the Conservation of Hydrocarbons, 1999 (see footnote 703) requires operators to take any reasonable measure, if economically justified, to use associated gas for any of the following purposes:

- maintenance of reservoir pressure in accordance with recognized technical procedures in the oil industry
- any internal, commercial, or industrial use, including its use as a fuel in the operator’s facilities
- injection into oil fields or other appropriate strata or underground storage, according to recognized technical procedures.

Article 22 states that any associated gas that cannot be utilized in the above ways must be disposed of in a manner that does not cause harm.

E. Measurement and Reporting

13. Measurement and Reporting Requirements

Article 13 of Decree 638/1995 (see footnote 704) states that the composition of emissions from flaring must be carried out by a minimum of three samples at each selected collection point when the study is carried out for the first time and a minimum of two samples after that. The runs should be carried out when the production volume is greater than the annual average. Article 26 requires operators to submit details of the composition of their emissions to MINEC at least annually.

Article 28 of Decree 1257/1996 (see footnote 708) requires submission of an Environmental Supervision Plan to MINEC for each project, together with the request for environmental authorization. In the case of hydrocarbons, the plan will be incorporated in the corresponding Environmental Impact Study. The Environmental Supervision Plan should include measures to mitigate the impacts of gas flaring and venting as well as the reporting of volumes and emissions.

14. Measurement Frequency and Methods

Article 6 of Decree 638/1995 specifies sampling period criteria (frequency, duration, and number of samples) to ensure compliance with air quality limits set in the decree. CO2 and methane emissions are not included in the decree, but sulfur dioxide, oxides of nitrogen, particulate matter, and other air pollutants are.

15. Engineering Estimates

Article 7 of Decree 638/1995 provides the analytical method, measurement period, and sampling method for each air pollutant covered by the decree. Sampling can be carried out either manually or automated via instruments. Analytical methods include automated approaches such as flame photometry and manual approaches such as colorimetry. MINEC may authorize other measurement methods if requested by the regulated party.

16. Record Keeping

No evidence regarding record-keeping requirements could be found in the sources consulted.

17. Data Compilation and Publishing

Both MinPetróleo and the PDVSA have published flaring data, with the last publication dating back to 2016.

F. Fines, Penalties, and Sanctions

18. Monetary Penalties

No information was found in the current legislation specific to penalties for flaring or venting. However, noncompliance with the pollutant emission limits established in Decree 638/1995 (see footnote 704) can trigger sanctions per Articles 108–135 of the Organic Law of the Environment, 2006 (see footnote 709). Article 108 states that financial penalties may be up to 10,000 tax units. Article 129 states that experts will determine the amount of damage, which will serve as the basis for sanctions and environmental measures.

The Environmental Penal Law, 2012,711 focuses on criminal behavior negatively affecting the environment and natural resources. Article 96 sanctions offenders with a monetary penalty of up to 2,000 tax units for emitting or allowing the escape of pollutants harmful to the environment.

19. Nonmonetary Penalties

Article 51 of the Organic Law on Gaseous Hydrocarbons, 1999 (see footnote 701) empowers the MinPetróleo minister to suspend activities for up to six months, depending on the seriousness of the offense and the offender’s past performance. Articles 112 and 119 of the Organic Law of the Environment, 2006 (see footnote 709) empower the responsible environmental authority to revoke licenses. Article 96 of the Environmental Penal Law, 2012, provides for imprisonment of six months to two years for emitting harmful quantities of gas or allowing it to escape.

G. Enabling Framework

20. Performance Requirements

No evidence regarding performance requirements could be found in the sources consulted.

21. Fiscal and Emission Reduction Incentives

Article 104 of the Organic Law of the Environment, 2006 (see footnote 709) provides three types of economic or fiscal incentives, which could in principle be applied to flaring reduction:

- a state-financed credit system
- exemptions from the payment of taxes, fees, and contributions
- any other legally established economic or fiscal incentive.

These incentives will be granted to persons who invest in preserving the environment according to the terms established in Article 102. The incentives aim to promote the adoption of clean technologies, environmental management systems, conservation practices, and the sustainable use of natural resources, as stated in Article 103.

22. Use of Market-Based Principles

No evidence regarding the use of market-based principles to reduce flaring, venting, or associated emissions could be found in the sources consulted.

23. Negotiated Agreements between the Public and the Private Sector

No evidence regarding negotiated agreements between the public and the private sector could be found in the sources consulted.

24. Interplay with Midstream and Downstream Regulatory Framework

The Organic Law on Gaseous Hydrocarbons, 1999 (see footnote 701) created the National Gas Entity (Ente Nacional del Gas)™ as a decentralized body, with functional, administrative, technical, and operational autonomy. The National Gas Entity reports to MinPetróleo and is responsible for coordinating the country’s gas development activities.

In 2002, PDVSA Gas, S.A. was established with the purpose of managing the commercial aspects of the country’s natural gas activities: exploration and exploitation of nonassociated gas; extraction, storage, commercialization, and distribution of LPG; and transportation, distribution, and marketing of natural gas. However, the domestic gas market is comparatively small, because electricity demand is met almost entirely by hydropower. Domestic gas prices are regulated at levels well below international prices, deterring the required investments in both associated gas and nonassociated gas development.
Glossary

battery  system of equipment, such as tanks, used to receive unprocessed crude oil or vessels separating oil, gas, and water from the fluid produced by one or more wells

conditional contribution  measures countries would take in a Nationally Determined Contribution (NDC) of the United Nations Framework for Convention on Climate Change (UNFCCC) if international means of support were provided or other conditions were met

downstream  marketing and distribution of treated natural gas and products derived from oil and natural gas

flaring intensity  a measure of the volume of gas flared per volume of oil produced, such as m³ of gas per barrel of oil

hydrocarbons  organic compounds consisting of carbon and hydrogen, such as oil and natural gas

midstream  storage, processing, and transportation of oil and gas, including the refining of crude oil

nonroutine flaring  flaring other than routine and safety flaring

routine flaring  flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market (excluding safety flaring, even when continuous)

sour gas  natural gas containing significant amounts of hydrogen sulfide

unconditional contribution  measures countries agree to take in an NDC of the UNFCCC based on their own resources and capabilities, without any conditions

upstream  exploration and extraction of oil and gas resources
The World Bank’s role in gas flaring reduction

The World Bank’s Global Gas Flaring Reduction Partnership (GGFR) is a trust fund composed of governments, oil companies, and multilateral organizations committed to ending routine gas flaring and venting at oil production sites across the world. The Partnership helps identify solutions to the array of technical, financial, and regulatory barriers to flaring and venting reduction by developing country-specific flaring reduction programs, conducting research, sharing best practices, raising awareness, securing commitments to end routine flaring through the ‘Zero Routine Flaring by 2030’ global initiative, and advancing flare measurements and reporting.