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**CARBON
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APG Flaring in Egypt: Addressing Regulatory Constraints

Final Options Report

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Abbreviations and acronyms

| | |
|--------|---|
| APG | Associated Petroleum Gas |
| bbbl | Barrel of crude oil |
| Bcm | Billion Cubic Metres |
| CAPEX | Capital expenditure |
| ECA | Economic Consulting Associates |
| ECHEM | Egyptian Petrochemicals Holding Company |
| EEAA | Egyptian Environmental Affairs Agency |
| EGAS | Egyptian Natural Gas Holding Company |
| EGPC | Egyptian General Petroleum Company |
| EIA | Environmental Impact Assessment |
| GANOPE | Ganoub El-Wadi Holding Company |
| GoE | Government of Egypt |
| GoR | Gas to oil ratio |
| GRA | Gas Regulatory Authority |
| IOC | International Oil Company |
| JV | Joint Venture |
| KEC | Kuwait Energy Company |
| LDC | Licensed distribution company |
| LPG | Liquefied petroleum gas |
| mmBtu | Million British Thermal Units |
| mmcm | Million Cubic Metres |
| mmscfd | Million standard cubic feet per day |
| MoP | Ministry of Petroleum |
| MRV | Monitoring, reporting and verification |
| MW | MegaWatt |
| NOAA | National Oceanic and Atmospheric Administration |
| OPEX | Operating expenditure |
| PSC | Production Sharing Contract |
| RA | Regulatory Authority |
| SEC | Supreme Energy Council |

Executive Summary

This Options Report is the main deliverable of the assignment *APG Flaring in Egypt: Addressing Regulatory Constraints* and combines the results and analyses of all previous tasks. The report makes recommendation on gas flaring regulatory reform options that would help to improve the existing regulatory framework and thereby increase levels of APG utilisation. The approach firstly assesses the existing regulatory landscape in Egypt, secondly reviews international lessons learned from gas flaring regulations and thirdly analyses the merits of different reform options for Egypt.

Major constraints to APG investments

The main constraint for investment in gas flaring reduction is the marginal economics of APG utilisation projects. This was presented in detail in the previous EBRD funded study¹ and is largely due to low gas prices, small and scattered volumes of gas flares, and high capital expenditure requirements for such investments. Consequently, only a small number of associated gas utilisation projects have been realised in Egypt over the past decade. The current market and policy conditions in Egypt are therefore not adequate to bring gas flaring levels down and provide crucial new gas supply sources for Egypt. Hence additional incentives are needed if gas flaring levels are to be reduced.

Besides the marginal economics of APG utilisation, we identify other constraints related to the regulation of gas flaring in Egypt. From our findings and stakeholder consultations the following factors limiting APG flare investments can be highlighted:

- o *Constraint 1: Lack of a transparent and well defined regulatory framework supported through secondary legislation* - While regulatory arrangements exist for gas flare limits and oversight responsibility, these are not formalised creating uncertainty and a lack of transparency for operators. This includes no transparent and enforced maximum flare levels, no gas flare permits system that could create direct accountability and no penalisation and enforcement mechanism.
- o *Constraint 2: no transparent monitoring, evaluation and validation process to ensure flare levels are within allowed quota.* Although operators are currently required to report gas flare levels to EGPC on a daily basis, no guidelines or requirements are in place that ensure consistent and accurate measurement.
- o *Constraint 3: insufficient 'pull factors' and economic incentives to improve the economics of gas flare reduction projects.* Whilst the regulatory framework can be considered a 'push factor', economic incentives can act as pull factors incentivising investments for operators. Most notable missing pull factors include no wholesale market mechanism to ensure gas prices are cost reflective and no third party access arrangements which would allow operators to sell APG directly to offtakers.

¹ *Associated Petroleum Gas Flaring Study for Egypt, Carbon Limits, EBRD, 2016*

- o *Constraint 4: no formalised process for appraisal and approval of flaring reduction investments.* Operators currently face uncertainty on the steps and administrative procedures that need to be taken to implement APG flaring reduction projects. As gas flaring reduction investments can be lengthy and costly to obtain approval for, streamlining the approval process and creating a transparent step-by-step guide to be adhered to by operators, would incentivise investments.
- o *Constraint 5: lack of clarity on the institutional responsibility for the implementation of gas flaring reduction.* Whilst EGPC has been nominated to monitor gas flare levels and enforce restrictions, this is not formalised in any form of legislation, creating uncertainty on the scope of EGPC’s regulatory responsibilities. Additionally, EGPC’s dual role of commercial joint venture partner as well as regulatory agency creates conflict of interest.
- o *Constraint 6: no formalised and GoE endorsed gas flaring policy.* Despite GoE commitment to reducing gas flaring, no clearly defined gas flaring policy exists. The policy can define the framework within which a regulatory framework can exist.

Regulatory framework reforms

To overcome the investment constraints and facilitate more APG utilisation, the GoE can adopt a set of reform options that would help redefine the regulatory framework. We assess a number of different reform options on the basis of international best practice and a set of policy criteria. The full set of reforms are summarised in the table below. Implementing all of these reforms would be onerous and results are only likely to emerge in the medium- to long-term. Our recommendation therefore focuses on a core set of reforms that can be adopted by GoE over the short- to medium-term and that could have significant direct impacts on gas flaring levels. These are highlighted in the table.

Figure 1 Summary of reform options

| Regulation & policy | Targets | |
|---------------------|------------------------------------|---|
| | | Industry-wide target acting as a medium term objective for the entire sector – these are not binding but will serve as indicator to redesign the framework if targets are not met |
| | Flaring permits | Permits for exceptional flaring if above threshold value or if flare reduction not economically or technically feasible |
| | Economic test (Core) | Operators need to assess the economic feasibility of gas utilisation investments on a frequent basis – if above threshold value, operators are required to make the investment |
| | Investment approval process (Core) | Implement a transparent decision tree outlining each step required for gas flare reduction approvals, the necessary documentation and the relevant government entity to obtain approval from. |
| | Minimum technical standards | Minimum technical standards operators need to abide by for those flaring activities that are permissible |

| | | |
|------------------------------------|----------------------------------|---|
| <i>Institutions</i> | Independence (Core) | Discontinuing EGPC's role as regulator; regulatory activities initially embedded into Ministry as sub-division. Ultimate objective should be for regulator to be independent. |
| | Regulatory scope | The new regulatory entity should have full regulatory responsibility for flaring, i.e. monitoring, evaluation, verification and enforcement |
| | Stakeholders (Core) | Stakeholder engagement should be a key component of the regulatory framework and regulatory processes |
| <i>Oversight & enforcement</i> | Metering/measuring (Core) | Technical standards and requirements for meters. Where not feasible to install meters: determine the methodology for estimating flares |
| | Reporting | Self-reporting within transparent and clearly defined format set by regulator |
| | Verification | High level, desk-based verification of reported data complemented with targeted inspections based on probability of non-compliance and health or environmental impacts. |
| | Enforcement | Penalties based on severity of non-compliance |

Six core reform options to prioritise

The first core reform option we recommend is the introduction of an **economic test to assess the viability of gas utilisation investments**. The test needs to be carried out by operators on a regular basis and if it results in an NPV or IRR value above a predetermined threshold, the operator is required to pursue the investment. The advantage of this approach is that it allows site specific factors to feed into the regulatory framework whilst ensuring operators are not unduly economically penalised. To be effective, the test, its methodology and format of presentation (spreadsheet) needs to be clearly defined by the regulatory agency. This approach is used in the province of Alberta in Canada and has proven highly successful. For this process not to be costly for operators, particularly smaller ones, we recommend an annual review of the economic test only for larger fields. Smaller field utilisation tests would have to be conducted every three years and should consider 'clustering', i.e. assessing economic utilisation across fields located within a predetermined radius.

The second core reform option we recommend is the implementation of a **transparent investment approval process**. Providing clarity on the steps and documents required for the approval of APG investments will help operators in realising investment more efficiently. We recommend this to be drawn up as a 'decision tree' where, for each step of investment approval, the necessary documentation and responsible government agency is specified. Additionally, the timing within which the responsible government agency needs to respond should be set out. The economic test will form a crucial first component of this decision tree and we would recommend to enable a 'fast track' option, where investments above a certain threshold value and meeting technical parameters will obtain approval more quickly. Currently this process is internalised with EGPC and we do not recommend that this should change. However we would recommend formalising it to create transparency and thereby incentivising operators to make investment decisions.

The third core reform option we recommend is to create **transparency on regulatory responsibility for gas flaring**. Ideally, operation and regulation should be separated and an independent upstream regulator established. However flaring is not a sufficiently extensive activity (in economic terms) to justify creating a stand-alone regulator. We therefore recommend that as a short- to medium-term solution a separate subdivision within EGPC acts as the regulatory agency. This subdivision should focus on gas flaring regulation exclusively. Its roles would encompass the full regulatory spectrum of monitoring of reported gas flaring volumes, evaluation of documentation provided by operators, inspection of sites to assess all technical standards are met and enforcement of regulations. In the medium-term this could be transferred to the Ministry and ultimately an independent regulator could be set up if flaring levels or other factors warrant it.

The fourth core reform option we recommend is to **set metering standards and estimation methodologies**. Transparency of gas flaring data and crucially comparability of data across sites and operators is of key importance when regulating gas flaring activities. We recommend specifying minimum technical standards for metering provisions. These should be adhered to if it is technically feasible to install or retrofit meters. If not technically feasible, the existing arrangements could continue to apply; however we would recommend a review of the existing arrangements by specifying a methodology to measure gas flaring volumes that applies to all sites. A detailed description on suitable metering and measuring standards is provided by GGFR² and we recommend adopting these as closely as possible. Importantly, the reporting responsibility for gas flare levels remains with the operator.

The fifth core reform option is a more **formalised process of stakeholder engagement**. A close and collaborative relationship between EGPC and operators seems to be in place already and we recommend building on this strong foundation. The engagement of stakeholders into shaping of the regulatory process has significant benefits and fosters a collaborative regulatory approach instead of a confrontational one. We would therefore suggest the creation of a consultative committee on gas flaring (GFCC). This would be chaired by the regulatory authority and would also include other representatives of EGPC and the Ministry of Environment, as concerned government entities, and industry representatives. The industry representatives should include both oil and gas producers and gas users. The membership should be balanced between government and industry representatives. The committee would meet at least twice-yearly and more often if required.

The sixth core reform option we recommend is the **drafting and publication of a gas flaring policy**. The policy shows commitment from GoE in reducing gas flaring and provides transparency to all stakeholders, and the wider public on APG utilisation objectives. The document should set out flare targets, key principles setting the framework of regulating gas flares, institutional responsibilities and an outline of the approach to reducing gas flaring levels.

These six core reform options will improve the regulatory framework in Egypt and help raise awareness among operators of gas utilisation investments. Together with the wider gas market changes envisaged under the new Gas Law, these reform options are expected to help in creating a more favourable investment environment.

² *Guideline on Flare and Vent Measurement*, GGFR, 2008 available at: www.worldbank.org/en/programs/gasflaringreduction#5

Roadmap of implementation for core reform options

To implement these changes we propose a series of incremental steps that can help to deliver the recommended package of measures in an orderly and structured way over coming years. The changes proposed are ambitious and can be onerous to implement, and it would be unrealistic to consider that these can be implemented overnight. We therefore propose a three-phase strategy that charts what we feel is coherent and manageable route to a more transparent and effective regulatory framework of flaring activities. Assuming a start date of activities in mid-2017, we estimate the full programme to be readily implemented by mid-2021. The implementation phases we recommend are as follows:

- o *Phase 1: Piloting APG flaring reduction;*
- o *Phase 2: Review and Strategy Development; and*
- o *Phase 3: Implementing the agreed Strategy.*

We propose that the starting point for addressing gas flaring should be the establishment of a Pilot Scheme that helps to gain experiences with implementation of the various measures outlined and supports operator readiness for revised approaches for APG management over the medium-term. A demonstration programme acts as a ‘soft-start’ rather than jumping straight to a regulatory approach, which may prove challenging to implement. We suggest that such a phase should focus only on a selected number of sites in a single geographical region (e.g. a group of fields within the Western Desert). The implementation steps for the pilot stage are as follows:

- o *Step 1 – National Stakeholder Workshop.* The initial step should be the holding of a national workshop on APG flaring with all interested stakeholders. The workshop would provide an opportunity for the Government to express its views and plans for tackling APG flaring, including presenting the results of the recent EBRD-sponsored studies and the objectives it intends to pursue in gas flaring. It will also provide the platform to establish the consultative committee described above (GFCC).
- o *Step 2 – Gas flaring policy.* One of the outcomes of the first step should be the determination of a gas flaring policy. GoE should set out its gas flaring objectives and key principles determining the framework that will define the implementation of the reform options.
- o *Step 3 – Initial Actions.* At the GFCC’s 1st meeting (to be held within 6 months of the National Workshop), it should work to establish two key elements: (i) common measurement and reporting protocols and guidelines and (ii) a flare permitting system. In parallel EGPC will need to establish systems for storing and analysing data reported by operators and for logging the flaring permits issued.
- o *Step 4 – Enhanced Actions* Following 6-12 months of reporting using the guidelines and the implementation of the permits established under Step 2, the GFCC should meet again to discuss how implementation is going and to consider enhancements to the scheme. The key enhancement should be the

introduction of the economic test including cluster analysis. Additionally, this would be a good point to introduce minimum technical standards for flares.

- o *Step 5 – Progress Review* A 3rd GFCC meeting should be held 1 to 1.5 year after the 2nd meeting. The purpose of the meeting would be to discuss experiences and exchange information in terms of measurement and reporting (guidelines, data quality, reporting and analytical issues), results of economic tests (ease of implementation, any modifications to be employed, results of analysis and planned actions arising from test results), and plans for remainder of pilot-phase (covering 1.5 to 2 years or so of further operation)
- o *Step 6 – Pilot Scheme Final Review* A 4th and Final GFCC meeting should be held where results of the Pilot Scheme are discussed amongst participants.

Subsequent phases 2 and 3 should focus on the rollout of the methods and processes developed during the pilot scheme. Note that we have not included a penalisation or enforcement system as a core recommendation in the pilot phase. We would expect the collaborative regulatory approach and the existing good relations between operators and EGPC to ensure economic tests are conducted on time by operators. This could however be revisited if the pilot phase is unsuccessful. A schematic of the roadmap, dates and responsibilities is shown in Figure 2.

Figure 2 Schematic of Gas Flaring Reduction Roadmap

| Reform action | Lead entity | Start date | Duration months | 2017 | 2018 | 2019 | 2020 |
|--|--------------|------------|-----------------|------|------|------|------|
| | | | | □□□□ | □□□□ | □□□□ | □□□□ |
| Phase 1: Pilot Scheme | | | | | | | |
| #1 National Stakeholder Workshop | | | | | | | |
| Establish Pilot Scheme area + GFCC | MoP/EGP | Jul-17 | 2 | ■ | | | |
| #2 Gas Flaring Policy | | | | | | | |
| Publish and draft gas flaring policy | MoP/EGP | Sep-17 | 3 | ■ | | | |
| #3 Initial Actions | | | | | | | |
| 1st Meeting of GFCC - Establish Measurement Protocol - Establish Flare permitting system | GFCC | Sep-17 | 3 | ■ | | | |
| Roll out Measurement Protocol | Operators | Dec-17 | 12 | ■ | ■ | | |
| Roll out Permitting system | EGPC | Dec-17 | 3 | ■ | | | |
| Compile data logging and evaluation system | EGPC | Dec-17 | 3 | ■ | | | |
| Research & Study tours on economic tests etc. | EGPC | Jan-18 | 8 | ■ | ■ | | |
| #4 Enhanced Actions | | | | | | | |
| 2nd Meeting of GFCC - Economic Tests - Minimum Technical Standards | GFCC | Jul-18 | 1 | | ■ | | |
| Roll-out Economic Tests | EGPC | Aug-18 | 2 | | ■ | | |
| Roll-out revised Permits with Technical Standards | EGPC | Aug-18 | 2 | | ■ | | |
| Implement Economic Tests and return results | Operators | Sep-18 | 4 | | ■ | | |
| Review and evaluate first economic tests | EGPC | Jan-19 | 2 | | | ■ | |
| Inspect Pilot Scheme facilities | EGPC | Mar-19 | 2 | | | ■ | |
| #5 Progress Review | | | | | | | |
| 3rd Meeting of GFCC - Information exchange | GFRC | Aug-19 | 1 | | | ■ | |
| Implement Economic Test and return results to EGPC | Operators | Dec-19 | 1 | | | | ■ |
| Review and evaluate second economic tests | EGPC | Jan-20 | 1 | | | | ■ |
| #6 Pilot Scheme Final Review | | | | | | | |
| 4th Meeting of GFCC - Final Information exchange - Strategy discussion | GFRC | Apr-20 | 1 | | | | ■ |
| Phase 2: Review and Strategy Development | | | | | | | |
| Develop strategy for wider roll-out: - Voluntary scheme; or - Regulatory scheme (mandates) | MoP, EGPC | May-20 | 3 | | | | ■ |
| Phase 3: Implement Agreed Strategy | | | | | | | |
| Implementation | All | Sep-20 | 5 | | | | ■ |

1 Introduction

This report is the main deliverable for the assignment *APG Flaring in Egypt: Addressing Regulatory Barriers*. It follows the Inception Report submitted in March 2016. The objective of the *Regulatory Barriers Report* is to identify the main regulatory obstacles to Associated Petroleum Gas (APG) flaring investments in Egypt. After a kick-off presentation in early March 2016, an inception visit in mid-March 2016 and an intermediate visit in September 2016, we present the results in this report of our assessment of the main constraints preventing APG investments.

Objective, approach and scope

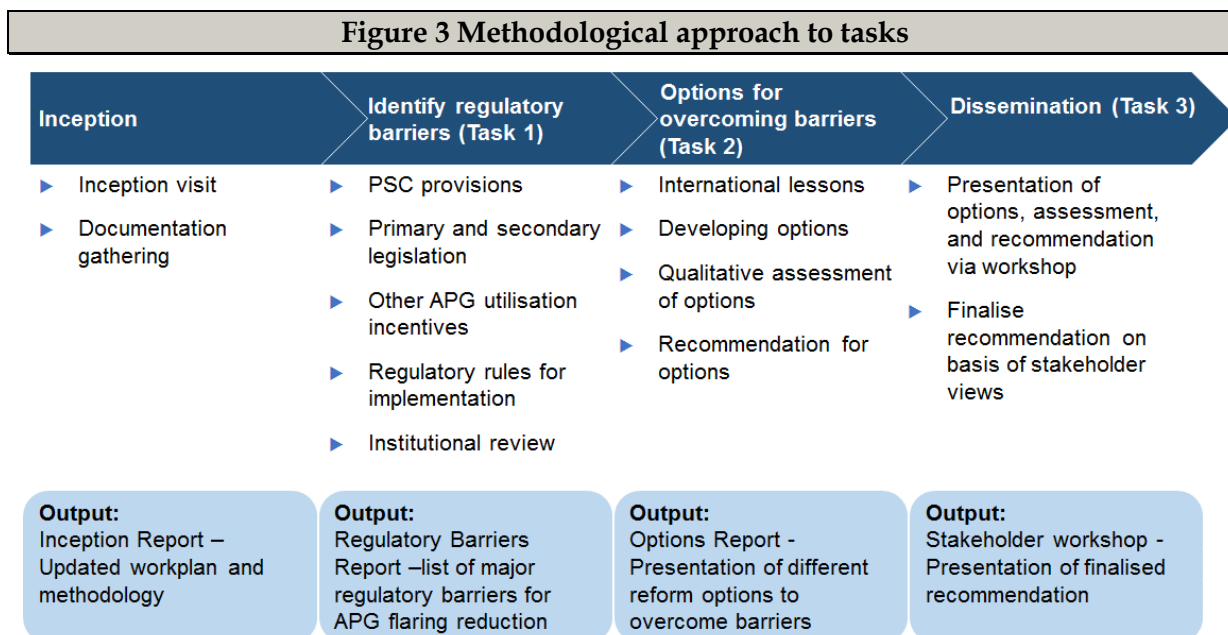
The main objective of the assignment is the recommendation of options to overcome the major regulatory constraints to investments that reduce gas flaring and venting. The recommendations need to be implementable and must have the support of major stakeholders.

The focus of the study is on upstream operations and it builds on a previous EBRD funded study *Associated Petroleum Gas Flaring Study for Egypt*³, which identified the volumes, nature and location of gas flaring in Egypt. As presented in the inception report, our approach consists of four tasks:

- o *Obtain all latest documentation and information on APG flaring levels in Egypt (Inception) – completed in March 2016*
- o *Identify and review regulatory constraints for APG flaring reduction investments (Task 1) – completed in July 2016*
- o *Develop and assess options for overcoming regulatory constraints (Task 2) – completed with this Report*
- o *Ensure recommendations are presented and disseminated to Egyptian stakeholders (Task 3) – to be completed in Q1 2017*

The tasks and their subtasks are summarised in Figure 3 and described in detail in the inception report. This report brings both task 1 and task 2 together and therefore identifies the main regulatory constraints for APG flaring reduction investments and proposes recommendations for regulatory changes to reduce gas flaring in Egypt.

Figure 3 Methodological approach to tasks



Source: ECA inception report

³ Carbon Limits, January 2016

This report

This Options Report is the main deliverable of the assignment and combines all results and analyses of previous tasks. The report sets out different reform options and also includes an initial recommendation on the content of regulations. The Report is structured as follows:

- o Section 2 provides an overview of the **status quo of gas flaring in Egypt**. This includes an overview of gas flaring levels and locations, the relevant components of production Sharing Contracts (PSCs), the existing regulatory and institutional framework of gas flaring.
- o Section 3 identifies the **constraints within the existing framework** to highlight the areas requiring focus to set up a regulatory framework.
- o Section 4 summarises the **lessons learned from the international case studies** presented in the Annex.
- o Section 5 presents the main components of a gas flaring regulatory framework and proposes different **options of reform** taking into account the existing constraints and international lessons.
- o Section 6 sets out the main components of our **recommended regulatory changes** to the gas flaring framework and proposes a roadmap for implementation. The intention of this section is to set out a basis upon which policymakers in Egypt can start developing and implementing tailored gas flaring regulations.

2 Gas flaring in Egypt

2.1 Background: gas market

A key component to successfully achieving gas flaring reductions is the use of incentives for APG utilisation beyond any direct regulatory provisions. This includes all factors that may contribute to the favourable economics of such investments. The most obvious incentives are related to gas markets and the ability of contractors to sell at a competitive gas price and to a number of different offtakers. Secondary incentives are the creditworthiness of gas buyers, which can lead to pricing and market arrangements of products that use gas as an input. In Egypt, this is the electricity sector. EGAS, as the single buyer of gas is heavily reliant on offtake volumes from power generators. Upstream contractors will consider these interlinkages when making an APG reduction investment decision.

2.1.1 Market overview

Egypt's gas market operates under a single-buyer model in which EGAS (since 2004, with EGPC being the government counterpart for older contracts) acquires gas from operators via Production Sharing Contracts (PSCs) or through joint venture (JV) partners, and then sells to the downstream market via the distribution networks of the twelve Licensed Distribution Companies (LDCs) (Figure 4). Prices are fully regulated and vary by sector (Figure 6).

Since 2014, EGAS has been contracting LNG imports due to demand growth outpacing supply. As part of efforts to reduce the strain on EGAS finances and supply, private consumers are allowed to directly contract supply from LNG shippers via bilateral agreements. Private sector consumers importing LNG are allowed to use the state-owned natural gas network in transferring and marketing the gas. A tariff, yet to be advertised, would be applied to private importers using the network.⁴ There has been little enthusiasm to undertake such agreements, either due to consumers preferring to have EGAS as their supplier at low, regulated prices (with the risk of supply interruptions and/or reduced quality of delivered gas) or consumers not being large enough to secure long-term contracts with shippers.

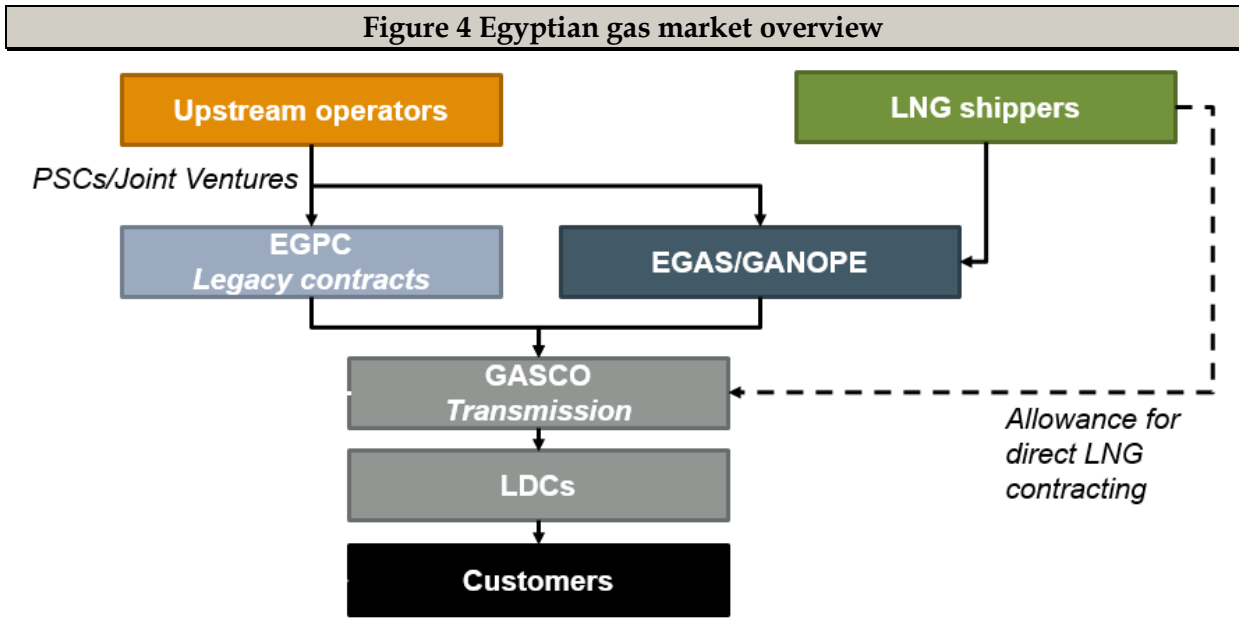
Outside of LNG, private sector participation is allowed in the upstream market through PSCs with EGAS or EGPC and in the distribution system under the LDCs. The vast majority of these entities are joint ventures. Foreign and Egyptian private companies are granted concession areas for exploration purposes in accordance with periodic bidding rounds administered by the relevant holding company.

Third parties (other than EGPC and EGAS) do not have non-discriminatory access to pipeline networks constructed for the transportation of oil and gas, with Third Party Access (TPA) only achieved through bilateral/multilateral agreements, but TPA is expected to be revised and implemented under the new gas law (see section 2.1.3).

A fully owned subsidiary of EGAS called GASCO is responsible for planning and operation of the transportation system. GASCO is the transmission system operator and is

⁴ 'Egypt permits private sector to import natural gas', The Medi Telegraph, 22 May 2015.

compensated for its operations with a volume-based fee. Since 1997, twelve LDC zones have been established to develop distribution networks through private participation. Ten of the LDCs are privately owned. Besides residential and commercial demand, LDCs can also serve large industrial consumers such as power generators, cement factories, and steel factories. LDCs undertake the role of expanding the pipeline infrastructure to facilitate access to the network, establishing connections to consumers, and providing operation and maintenance services.



The LDCs are distributors of natural gas but not suppliers. EGAS is the sole supplier to the domestic market, selling directly to residential, commercial and industrial customers, and power plants using GASCO’s transmission network and the distribution networks of the LDCs. Revenues are collected by LDCs if the customers are connected to the distribution network but are passed through to EGAS. LDCs therefore obtain no revenue from trade. However, to operate and maintain the network, LDCs receive a commission from EGAS, which is subject to a regulated cap.⁵

2.1.2 Recent supply issues

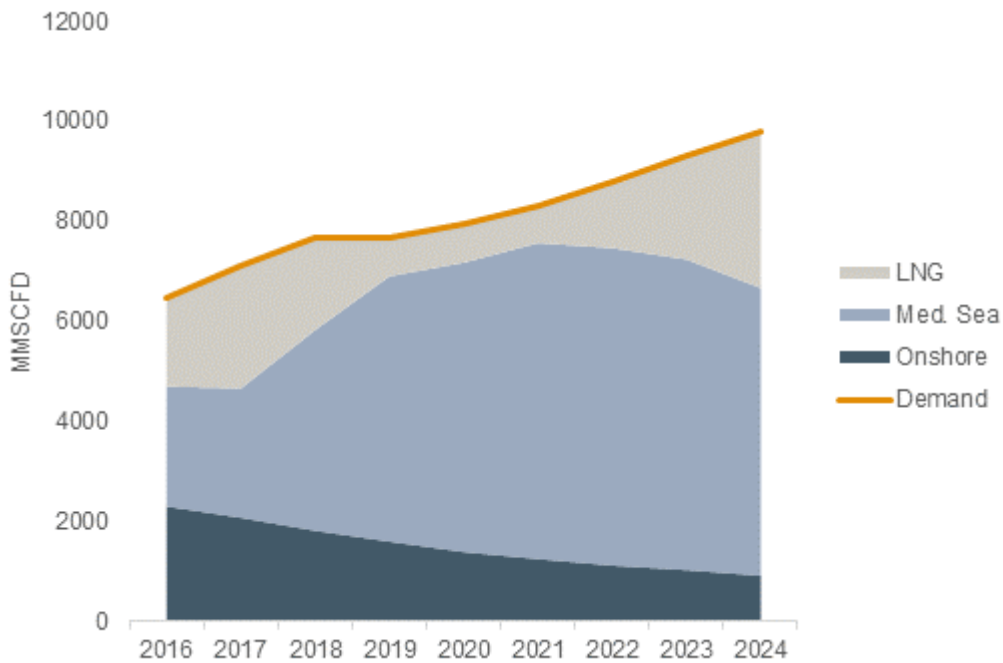
As noted previously, Egypt has become a net importer of gas in recent years, increasing the cost of supply as Egypt has had to turn to costly LNG imports and the bulk of domestic production shifts to offshore fields. Egypt’s domestic production will increasingly come from the Mediterranean Sea and it is projected to continue to rely on LNG imports to meet growing demand, even despite ENI’s recent giant discovery (Figure 5). This will exacerbate the financial troubles of EGAS, as \$3/mmBtu gas for power, by far the largest gas consuming sector, is unlikely to be sustainable as the financial cost of gas production in Egypt gradually approaches the economic cost, which will likely remain the price of LNG and new deep-water fields. The \$4-5.88/mmBtu price negotiated for ENI’s new discovery is

⁵ According to Decree 820/1996, concessions are issued to LDCs by EGPC but EGAS has since taken over this function.

a sign of the ‘new normal’ for Egyptian domestic production costs.⁶ Furthermore, while LNG prices have been depressed of late (Asian markets had an estimated landed price in September 2016 of ~\$5.50/mmBtu compared to an average of \$7.50/mmBtu in 2015),⁷ an ongoing need for LNG supply will be a source of supply cost uncertainty.

Egypt has also struggled to maintain foreign reserves and has been depreciating the Egyptian Pound,⁸ which has caused operators to refuse payment in Egyptian Pounds and insist on payment in either US Dollars or British Pounds. This has badly hampered EGAS’ ability to pay operators and LNG shippers as Egypt’s foreign reserves deplete.

Figure 5 Egypt Supply-Demand forecast, 2016-2024



Source: Ministry of Petroleum and EGAS data, ECA calculations.

The government has again sought to reduce fuel subsidies as gas shortages and budget deficits have emerged. July 2014 price reforms increased gas prices for all sectors except residential users (Figure 6). However, despite increasing gas prices for the power sector by 273%, they remain far below LNG import prices.⁹ In light of the outsized volume of gas consumed by the power sector compared to other sectors, subsidies are therefore likely to continue to weigh on public finances. Furthermore, interviews with local industries suggest they are struggling to pay the high gas prices and are instead running up large unpaid bills with EGAS.

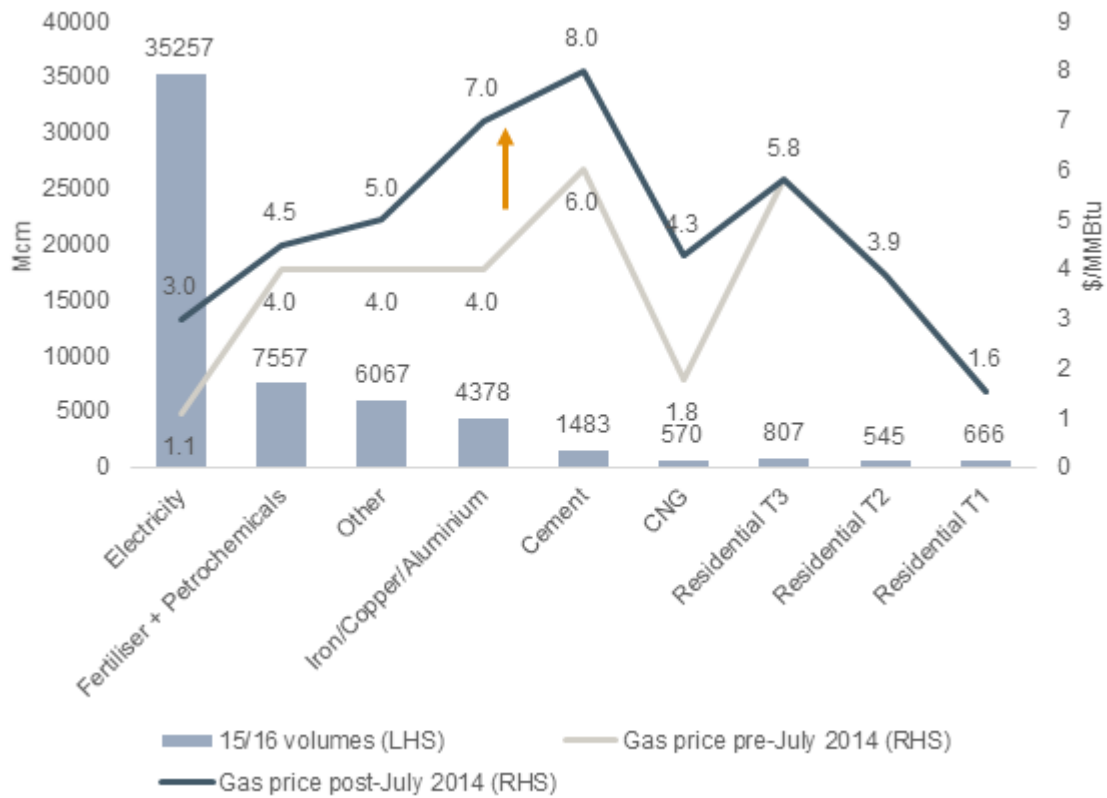
⁶ *Eni to complete second well in Zohr field by April for 100m*, Daily News Egypt, 10 February 2016

⁷ FERC, *World LNG Estimated Landed Prices*, October 2016. Note the final supply cost would also include regasification, transmission, and distribution costs, as well as a rate of return.

⁸ Most recently in November 2016: The Wall Street Journal, November 2016, ‘Egypt Free Floats Its Currency, Devaluing It Against the Dollar’.

⁹ The exact LNG import price is not known; however LNG cargoes in Spain as of September 2016 were delivered at 5.30 US\$/mmbtu – FERC website, World LNG landed prices.

Figure 6 Gas pricing and volumes – July 2014 reforms*



Source: Ministry of Petroleum, EGAS. *Incorporates amendments.¹⁰

2.1.3 New Gas Market Law

The New Gas Market Law (“the draft Law”) is currently in the process of being finalised. An initial draft of the Law has however been made available and the following key features can be highlighted:

- o *Independent regulator for mid- and downstream operations* – the draft Law establishes an independent regulator for gas. Its responsibilities would be in transmission and distribution price setting, licencing, market monitoring and enforcing third party access. The focus of the regulatory agency would be only on mid and downstream activities, however, and would therefore not include upstream activities. No upstream regulator exists as per the draft New Gas Law.
- o *Two-tier market* – one of the most important changes envisaged in the draft Law is the establishment of an unregulated market. The unregulated market would

¹⁰ Note: Given the recent Zohr field find, lower recent LNG prices, and industry struggles, the Egyptian Government has sought to soften its plan to remove fossil fuel subsidies. The Government announced plans to lower the natural gas price for steel and iron factories to \$4.5/mmBtu in March 2016,¹⁰ though the Government was reconsidering this decision as of May 2016. Exception was also given to the glass industry, which saw its price drop from \$7/mmBtu to \$5/mmBtu. Furthermore, in light of recently floating the Egyptian Pound, Egypt has also begun raising energy prices as part of securing an IMF loan agreement: Financial Times, November 2016, ‘Egypt raises energy prices hours after floating currency’.

be made up by ‘qualified’, i.e. eligible consumers, who can negotiate contracts bilaterally with producers. This essentially expands the existing arrangements for LNG imports to domestic production. This market would exist in parallel with the regulated market for all consumers who are not eligible. No details exist in the draft version of the law regarding the selection of qualified consumers. However, this will likely be based on creditworthiness, loads and ability to pass on costs.

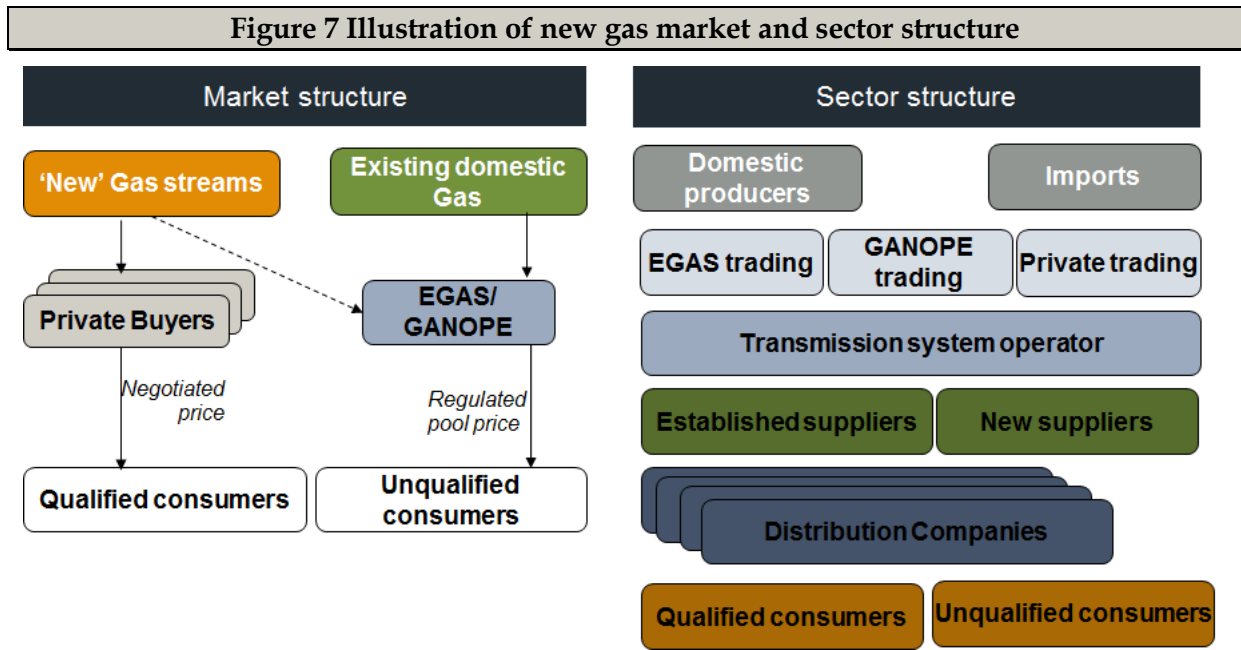
- o *Non-discriminatory access to infrastructure* – to ensure the two tier market can function, non-discriminatory access to both distribution and transmission grids will be granted. This means that all gas suppliers will be given access to the network at a separately regulated transmission and distribution tariff. The transmission system operator will need to provide fair access to all on the basis of contracts and system stability.
- o *Separate tariffs for transmission and distribution* – as noted above transmission and distribution tariffs will be regulated separately; however no methodology and regulatory approach is determined in the draft Law.
- o *Legally unbundled sector structure* – following on from the full TPA, the sector structure will have to be unbundled. In particular the transmission system operation and ownership is to be legally separated from trading and commercial activities. Provisions for organisational structures and management structures are made in the draft Law to ensure full legal separation from transmission, operation and trading.
- o *Legal provisions for transmission and distribution network codes* – the draft Law also identifies the need to develop separate network codes for distribution and transmission to ensure fair access to the network exists so that the system can cope with several suppliers and the two tier market.
- o *Integrated system planning* – 5 year development plans are to be submitted by the system operator and approved by the regulator. This will ensure coordinated planning of infrastructure based on load developments.

The draft version of the Law lacks details on the exact implementation of many of these features. However the general approach to market and sector changes is clear: liberalisation, increased competition and cost reflective pricing. Figure 7 illustrates the market and sector structure as understood by ECA at this early stage of the draft.

The figure shows that the market structure is likely to be split by gas streams¹¹. No provisions in the draft Law exist to forcefully release some of the volumes currently sold through PSCs or Gas Sales Agreements from EGAS to the new suppliers/private buyers. We therefore assume that mainly new gas streams (of which associated gas could be one), would be directed towards the unregulated market of qualified consumers. The sector structure would not be that different to the current arrangements except that GASCO would not be a subsidiary of EGAS but a legally separated company. EGAS and GANOPE would be trading businesses which continue to sell to the regulated market. New traders and

¹¹ The term ‘gas streams’ refers to the origin of gas supply. As shown in the diagram, different regulatory and market conditions could apply to import gas streams compared to domestic production from existing PSCs.

suppliers could emerge, however, which could trade on the unregulated market. Transmission and distribution system operation would be separated from gas ownership to avoid conflicts of interest for the enforcement of third party access.



Source: ECA

2.2 Gas flaring levels and location

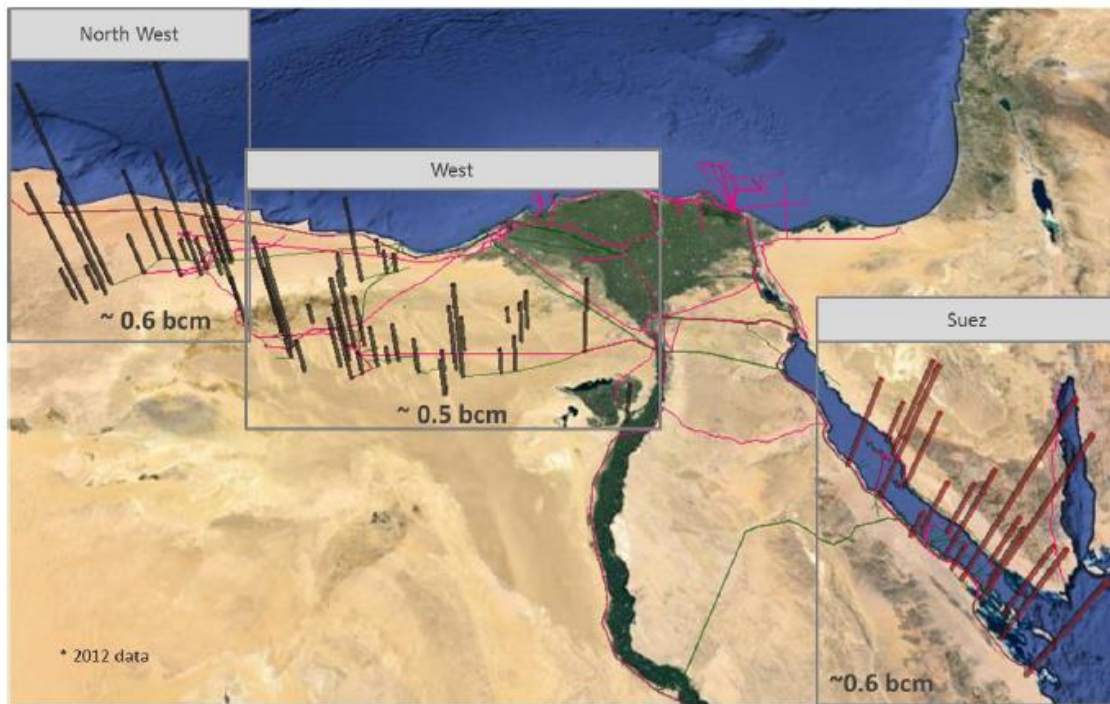
To understand the regulatory constraints to investments to reduce gas flaring in Egypt, sources, volumes and locations of gas flaring sites first need to be identified. From the EBRD funded study *Associated Petroleum Gas Flaring Study for Egypt* completed by Carbon Limits in January 2016, a number of key insights in Egypt’s gas flaring activity can be highlighted.

Gas flaring levels have remained close to 1.7 Bcm per year at oil producing sites. This represents over 80% of total gas flaring in Egypt - the remaining flare volumes occur at gas processing facilities. Total gas consumption in Egypt is 48 Bcm, suggesting that gas flaring at oil production sites represent 3.5% of total gas consumption. Gas flaring intensity (flare to oil ratio) has remained stable over the past 15 years.

Geographically the Western Desert and North West regions are the main areas where flaring occurs. Oil fields in these regions account for 62% of total flaring (~1.1 Bcm/y in 2012) and the estimated future volumes are likely to increase as the oil fields are less mature than in the Gulf of Suez region. The table in Figure 8 also shows that the west and north-western regions have the highest flare intensity.

Flaring is scattered across a large number of smaller oil fields. 70% of gas flaring volumes occur at sites with flare volumes of 5 mmscfd or less. Of those, the average flare volumes is 1.8 mmscfd or 0.0185 Bcm per year. Only 5 sites (of the two thirds reviewed) have flare levels above 7.5 mmscfd. This suggests that any regulatory framework aimed at reducing flare volume has to be flexible and ensure that site specific characteristics are taken into account.

Figure 8 Location of gas flaring



| | North West | West | Gulf of Suez |
|---|--------------|-----------------------|--------------|
| Share of total flaring (2012) | ~36% | ~26% | ~38% |
| Development from 2010 to 2014 | increasing ↗ | Fluctuating, stable → | Decreasing ↘ |
| Share of oil production (2012) | ~ 30% | ~ 20% | ~ 45% |
| Flare intensity, m3 gas / m3 oil (2012)(**) | 48 | 63 | 41 |

(*) Comprising Gulf of Suez, Sinai and Eastern Desert; (**) Flare intensity for Egypt: 48 m³ gas / m³ oil

Source: Associated Petroleum Gas Flaring Study for Egypt, Carbon Limits, EBRD, 2016

Access to gas transport infrastructure from flare sites is relatively good. As a whole, almost half of all flaring in Egypt is within 5 km from the nearest gas pipeline. Of the sites far away from infrastructure, around 50% have flare volumes below 1 mmscfd, which makes them stranded. This analysis provides a high level indication of reasonable access to transport infrastructure. However, besides gas pipelines, gas processing plants and their technical availability also play an important role and a more thorough field specific assessment is required to draw insightful lessons from this analysis.

The most promising options for reducing gas flaring in Egypt are power generation and gas delivery by pipeline or mobile equipment. In total eight different options for flare reductions can be considered. These are:

- o **Power for own use:** associated gas is captured and used for power and heat at the production site.
- o **Power for own use and delivery to a market:** includes the activities in ‘Power for own use’ and in addition has facilities and capacity to supply power to a grid owner/power utility or directly to targeted end-users outside the production site.

- o **Gas delivery by pipeline:** gathering, pre-treatment and transportation of associated gas for export by pipeline for further processing and/or end use.
- o **Gas delivery by mobile equipment (CNG/LNG):** treatment and transportation of the associated gas from the production site as compression (CNG) or liquefaction (LNG), normally by trucks or train.
- o **Small and medium size gas to liquids (GTL):** small scale GTL technologies (GTL Fischer-Tropsch or GTL-methanol) under development for utilisation of stranded associated gas at remote small and medium size fields.
- o **Reinjection of gas:** associated gas being reinjected for storage and/or for enhanced oil recovery (EOR).
- o **Large scale gas processing and delivery by pipeline:** large investments not only involving associated gas and/or a green-field development, but also including a broad set of investment in oil and gas processing facilities and transportation solutions.
- o **Large scale LNG/GTL/GTC:** As with 'Large scale gas processing and delivery by pipeline', economy of scale is critical for this option, with projects under this category being primarily based on non-associated gas supplies. Associated gas can be used, but the quantities would be too small, and supplies not stable enough, to meet the entire gas supply required.

Due to the small volumes of individual flare sites and site specific factors, the first four listed options have been identified as the most suitable options for Egypt. While the other options are not unattractive, they are not as central to a gas flaring reduction strategy as power for own use, delivery to the market, delivery by pipelines, and/or delivery by CNG/LNG.

According to the analysis in the previous report, the economics of gas utilisation hinge on the gas price, electricity price and distance to grid¹² – in general an economic case for the majority of flared gas is difficult in the current circumstances. The main prerequisites for making utilisation projects economically feasible can be summarised as follows, in order of volume:

- o For small-scale flare sites (**≤1 mmscfd**) located more than 10-15 km from the gas market, establishment of a virtual pipeline based on CNG trucks is attractive compared to a conventional pipeline export solution.
- o Among the solutions capable of eliminating routine flaring, only pipeline projects can be economic at current price levels, but then recoverable gas volumes must be medium or large in scale (**≥ 5 mmscfd**) and distances to the grid modest.
- o Production of power on-site to meet demand for local loads is typically attractive if diesel prices are above 300 US\$/ton, where both recoverable gas volumes and

¹² Other factor identified as obstacles to gas flare utilisation investments are site specific CAPEX needs, costs of emissions, field's remaining lifetime, ease of field tie-backs, and access rights and terms for available physical infrastructure.

power demand exceed the capacity of commercial scale units (typically >0.3 MW load and >75 mmscfd fuel gas available).

It is important to note however that this analysis is fairly generalised, and each APG utilisation project will have its own specific parameters of oil production shut-in, capital costs, oil well management and distance to grid. A proposed regulatory framework must therefore ensure that these project specific parameters are taken into account.

2.3 Production Sharing Contracts

2.3.1 Overview

Concessions are granted in Egypt through international bid rounds for local, regional and international oil companies. Offers are usually evaluated based on competitive parameters such as: percentage of production allocated for cost recovery; production sharing for gas and crude oil as profit shares; signature bonus and production bonuses; and the financial and drilling commitments in the different exploration periods.

All PSCs specify a percentage of the petroleum production for 'cost recovery' and the remaining being used for production sharing and called 'profit Petroleum'. Once a commercial discovery is made and a Development Plan and budget are approved by EGPC, a Development Lease is granted and issued by a document signed by the Minister of Petroleum and becomes part and parcel of the law. Following the issuance of a Development Lease, a Joint Operating Company (JOC) is incorporated between the concessionaire or operator (hereafter referred to as the "contractor" in the remainder of this document) and EGPC/GANOPE for the purpose of operating, managing the implementation of the plan and producing from the field. The finance of the JOC is provided by the contractor on a monthly basis through a cash call.

With regular production of petroleum commencing, a cost recovery mechanism becomes effective. Costs to be recovered can be grouped in three categories:

- o ***Exploration and development costs*** – recovered on a quarterly basis over a period of five years (i.e. 20% per annum) from the point of first production.
- o ***Additional capital expenditure*** – recovered on a quarterly basis over a period of five years (i.e. 20% per annum) from the point of the assets becoming operational.
- o ***Ongoing operating expenditure*** – recovered on a quarterly basis when incurred.

If in any one quarter, the sum of cost components from these three categories exceeds the cost recovery percentage, additional costs can be carried over to the next quarter. The amount to be carried over is the cost exceeding the percentage allowance. The allowance applies to all cost components and the carry forward therefore does not distinguish between capital and operating costs. If, in any quarter, the sum of costs from the three categories is below the cost recovery percentage, the excess cost recovery becomes the entitlement of EGPC.

2.3.2 Gas provisions in PSCs

The large majority of PSCs in circulation contain, by default, a gas clause. The gas clause was introduced in 1988 and all contracts negotiated or renewed after this date have included the clause. As the lifetime of development leases for petroleum products in Egypt is 25 to 35 years¹³, this means that almost all PSCs today include the gas clause. Additionally, producers in areas with high potential volumes of associated gas applied for the gas clause to be incorporated early on. Producers were attracted by the benefits of a formalised commercial arrangement for natural gas and thereby APG.

A full survey of PSCs would have to be done to identify the precise number of contracts without a gas clause, which is outside of the scope of this study. On the basis of our extensive experience in upstream operations in Egypt, we estimate the number of petroleum contracts without a gas clause to be less than 5% of all contracts. This means that the gas clause is the main factor determining investment incentives for APG flaring reduction in Egypt. Understanding the key features of the gas clause will therefore guide the identification of the main constraints in PSC's for associated gas investments. The key features of the gas clause are as follows:

- o **Cost recovery** - Associated gas is to be treated like liquid hydrocarbons (i.e. petroleum) and is therefore subject to the same terms of the cost recovery mechanism as crude oil. This share of hydrocarbons is known as 'Cost Recovery Petroleum'. The remainder of gas and/or oil is split by the profit share as indicated in the PSC (see profit split in next bullet). The mechanism of cost recovery is to allow a maximum percentage of production¹⁴ to recover the cost of exploration, development and operations (excluding cost of finance). While the profit split of oil and APG is the same, the valuation of these hydrocarbons is different. The oil value is based either (i) on the weighted average market price realised from sales during the quarter by EGPC or contractor whichever is higher or (ii) following detailed procedures relating oil API and netback to the daily price of Brent over the quarter. For the valuation of gas, see bullet point four in this section.

Operating costs are recovered in the same quarter. All capital costs however are recovered in quarterly instalments, typically over a five year period (though this can vary). If, for any quarter, the maximum percentage share of production is not sufficient to recover the cost in that quarter, the excess cost is allocated to the next quarter to be recovered then. As outlined above, the costs that are eligible for the cost recovery component include costs incurred during exploration (prior to commercial discovery); development and capital investments required to maintain and upgrade the facilities as well as operations. All costs associated with flaring investments and their operation are eligible as long as they are part of the approved development plan of the field. Note that developments plans are dynamic and can be changed at any stage of their life subject to approval by the

¹³ The standard duration of the agreements is 25 year, however exceptional extensions are granted to 35 years under exceptional circumstances or gas and oil discoveries are found in the same development lease.

¹⁴ Typically this will be around 30% of production, but varies for each PSC depending on cost factors, production volumes and field specifications

regulatory body. Once gas flaring investments are approved, they are treated like all other investments.

- o **Profit split** - The 'Profit Petroleum', i.e. the remaining share of gas after cost recovery, is split between EGPC and the operator by an agreed ratio.. The split of Profit Petroleum varies substantially from one PSC to another. It can range from 85:15 to 65:35 between EGPC and the operator respectively. In areas close to existing facilities requiring little investment or onshore the split will be skewed toward EGPC. However in more difficult areas, like deep waters where the cost of development is higher (as is the case for the Zohr field), the profit split will be skewed towards the upstream operator. Most contracts include an escalation factor, which increases EGPCs share as production volume rises. This escalation factors is determined separately for oil and gas in the PSCs.
- o **Fiscal terms** - Fiscal terms for Petroleum, whether it be gas or liquid, are similar for all fuels except for pricing where different international benchmarks are used for oil, gas and LPG. Traditionally, "Fiscal Terms" is used to indicate cost recovery, split of Profit Petroleum, recovery terms of capital and operating expenses and signature and production bonuses. So, all the elements that will be included in the cost recovery component (see bullet 1). Setting the same fiscal terms for gas and liquids in the gas clause does not take into account the different cost structures of investments for the different hydrocarbons.
- o **Valuation of gas** - As outlined above, oil and gas are priced differently. For gas, including APG, the valuation went through different phases. The first pricing system, introduced in 1988, used the price of fuel oil as an indicator. This was changed to the 'Gulf of Suez mix' (1995) and the price of 'Brent' (2000). The latter change also included a price cap of 20 US\$/bbl, which proved to be the main reason for slow upstream developments in Egypt. A new progressive gas pricing system therefore had to be introduced. The provision in the gas clause today is as follows:

'The cost recovery and production sharing gas price for local market will be agreed upon between the Contractor and EGPC or EGAS after the commercial discovery and before converting an area to Development Lease(s). Production Sharing Gas Price for export will be valued at Netback Price.'

This means that gas prices are effectively to be negotiated bilaterally between the contractor and either EGPC or EGAS if the gas is to be sold to the domestic market. For exports, international gas price benchmarks are used to then deduct costs of the value chain to remain with the netback price.

- o **Ownership of gas** - Ownership of recovered APG is entirely with government entities, namely EGPC, EGAS or GANOPE. This means that APG utilisation needs to be approved by a Government entity. PSCs do grant the right to operators to use APG in operation on site and allows operators to retain part of the recovered gas as per the profit share, however.
- o **Gas Sales Agreement with EGAS or EGPC** - existing provisions in the PSCs specify gas sales agreements to be made with EGAS or EGPC. This means that no explicit allowance is made in PSCs for direct contracts with private gas

suppliers. As part of the draft New Gas Law, however, a two tier market will be established with the possibility for bilateral contracts between upstream producers and offtakers directly. This would not require a review of the PSCs, but higher negotiated prices are likely to have an impact on cost recovery. A more detailed discussion on the impact of the draft New Gas Law on APG reduction investments is provided in section 2.1.3.

- o **No specific APG flaring clause** - associated gas is not addressed specifically in the PSC, but included as part of all other hydrocarbons under the term 'Petroleum'. Implicitly, the management of APG should be taken into account when a development project of crude oil discovery is presented to EGPC, however. In the old agreements (without a gas clause), provisions are in place indicating that EGPC and the Contractor shall agree the best way to economically exploit the associated gas to the welfare of the reservoir management and of both parties.
- o **'Take or Pay' and 'Deliver or Pay' agreements**- to ensure a critical volume of gas is sold, a minimum offtake level of 75% of sales volumes (as agreed between the contractor and EGAS/EGPC) is set in a Gas Sales Agreement. If, in any year, less than 75% is purchased by EGAS, EGAS needs to compensate the contractor for the shortage not purchased. This compensation is to be transferred in a separate account, which can be used by EGAS in the following year for any sales offtake volumes exceeding 75%. To incentivise the contractor to deliver the agreed amount a 'deliver or pay' agreement also exists in the PSCs. This agreement allows EGAS to purchase shortfall gas (the difference between 75% of agreed volumes and delivered gas) at a 10% discount.

2.4 Regulatory framework

2.4.1 Overview

Egypt does not have a comprehensive, well-specified, regulatory framework that focusses specifically on gas flaring. This means that there is no secondary (or primary) legislation in place that acts as catalyst or incentive for operators to reduce gas flaring levels. Additionally no technical norms, rules or standards exist that guide operators in gas flare reduction investment decisions. Lastly, no gas flaring policy has been passed by GoE that would outline objectives and cement Government commitment to reduction of APG flares. Consequently no formalised (via decree, guidelines, or legal provision) institutional arrangements are in place to monitor, verify and evaluate gas flaring volumes.

Despite the lack of such 'formal' structures for APG flaring, a *de facto* regulatory arrangement is in place that defines a framework for gas flaring reporting in conjunction with routine reporting of hydrocarbon production. These arrangements are not supported by secondary or primary legislation or any other form of Government guidelines. Consequently the resulting framework is poorly defined with unclear processes, requirements, penalties or verification procedures and lacking key components required for a successful regulatory regime. The main features of the existing framework and the resulting lack of transparency are:

- o **EGPC as gas flaring monitoring entity** – EGPC acts as the *de facto* regulatory agency to monitor gas flare levels and enforce flare limits (see next bullet point). EGPC’s role is, by law, defined as monitoring hydrocarbon production which includes APG. However the scope of its mandate specifically for gas flaring and venting is not clearly defined. This creates uncertainty as to the activities EGPC can initiate and the regulatory powers that it possesses. Additionally, EGPC faces a conflict of interest by acting as commercial partner in upstream operation and simultaneously its regulator, including APG flaring.
- o **Maximum flare limit** – a maximum gas flaring level 1 mmscfd is specified in the development lease agreements between EGPC and the contractors. The same limit applies to all oil fields; however its implementation is subjective and done on a case-by-case basis by EGPC. Some factors that influence the implementation of the limits is the gas to oil ratio, the geography of oil wells in each production area or region (scattered or narrow/very close), the volume of flared gases, the existence of a nearby gas processing facility and infrastructure (gas pipelines and networks), etc. The types and levels of penalties for non-compliance are unclear; however one option is that oil production may be shut-in to reduce gas flaring levels. This is difficult to implement: with EGPC acting as the regulatory agency it faces potentially competing and conflicting objectives of, on the one hand, gas flare reduction and on the other, crude oil output maximisation. While some gas flare utilisation options exist to combine these objectives (e.g. enhanced oil recovery), they are not necessarily always applicable and/or result in temporary oil production shut-ins.
- o **Reporting obligations on gas flaring** – according to EGPC operators are required to report gas flaring levels to EGPC on a daily basis. The following factors contribute to the lack of transparency of the existing reporting framework:
 - o There is no secondary legislation, guidelines or Government decree determining the requirement for EGPC to act as regulatory entity. Whilst its responsibility of monitoring gas flare levels is supported in primary legislation, the implementation of APG flaring reduction is not. There is therefore no formal institutional responsibility to oversee gas flaring reduction.
 - o There is no formal, clear and unified procedures and methodology for measuring flared gas volumes. This makes the reporting process unclear and creates significant uncertainty related to the accuracy of measurement consequently making comparability among different operators more difficult.
 - o There are no minimum technical standards that need to be met by operators for metering provisions. This together with a lack of universal flare measurement methodologies means that the accuracy of gas flaring levels is uncertain.
 - o EGPC’s role is limited to reviewing volumes of flared gases; however there are no measures in place that would help EGPC in verifying whether the reported numbers are indeed accurate. The lack of such verification

procedures and uncertainty on actual reported means EGPC may find it difficult to take corrective actions to reduce volumes of APG flared.

2.4.2 Environmental legal framework for APG flaring

Whilst primary and secondary legislation relevant for oil and gas sector operations do not include specific text on flaring, some relevant provisions exist under Law No. 4/1994 (Law on the Environment). Permission to flare is given by EGPC in the context of the Environmental Impact Assessment (EIA) approval, subject to consideration of whether it can be marketed and whether it exceeds operational requirements.

Environmental Impact Assessment process

Law No. 4 acts as the main legal base in Egypt for environmental protection, with Executive Regulations set out in 1995 (via Decree No. 338 of 1995 and amended several times the last of which is via Decree No. 544 of 2016). The law established the Egyptian Environmental Affairs Agency (EEAA) and requires submission of an EIA for new project developments in advance of the project. Major new investments and developments in the upstream sector such as new field developments and flare reduction projects require an EIA.

For oil and gas operators, the competent administrative body and licensing authority is EGPC, whose Environmental Department is required to assess the EIA of the proposed operation before granting the company a licence to develop the project. The EGPC registers the documents and reviews the documents (according to a checklist prepared by EGPC in cooperation with EEAA) and formally submits the applicant's documents to the EEAA for review and evaluation. The EEAA evaluates the documents and submits its opinions and any recommendations to the EGPC within a maximum of 30 days of the EEAA's official receipt of the complete documents. The documents are registered by the EEAA together with its opinion in the EIA register at the EEAA. The EGPC ensures implementation of the EEAA decision (i.e. approval, approval subject to further information being provided, or rejection).

EIA guidelines

Sectoral guidelines have been developed in order to elaborate the EIA process. The Environmental Management Sector within the EEAA deals with the EIA in more detail at the review stage and through the production of the guidelines. The EEAA, in coordination with the EGPC has published sectoral guidelines for the oil and gas sector: "Environmental Impact Assessment (EIA) guidelines for Oil and Gas sector" (October 2001). These address the full EIA process for activities related to the exploration and production of onshore and offshore of oil and gas resources in Egypt. They list the information to be provided for project approval, including descriptions of the proposed establishment (facility or project), the environment, and legislative and regulatory considerations; identification of potential impacts; description of alternatives to the proposed project; and mitigation management and monitoring plans. An outline of the required EIA report format is provided. The guidelines do not specifically address flaring and venting, although mitigation measures must be identified for 'significant environmental impacts'.

EGPC grants permission to flare gas that cannot be marketed and that exceeds operational requirements in the context of the EIA approval at each operational stage, including well testing (GGFR, 2004)¹⁵. Where flaring and venting are necessary, pollutant emission concentrations must not exceed the maximum permitted limits, set in relation to international standards as approved by EGPC (outlined in the Annexes to the Law 4/1996 Regulation). Measures must be taken to ensure the complete incineration of gas (for example, optimum size and number of burning nozzles, introduction of additional air, or the use of diesel fuel to enhance the incineration).

The company must maintain a register whilst carrying out the licensed activities that shows any impact on the environment. The register must include amounts and volumes flared and vented from oil production facilities. Operating companies thus report on a regular basis flare volumes to EGPC, although there does not appear to be specific reporting instructions for flare data submissions (Carbon Limits, 2016). However, a recent analysis of likely flaring volumes in Egypt, making use of recently published National Oceanic and Atmospheric Administration (NOAA) satellite data¹⁶ indicates deficiencies in data collected by EGPC. This is attributed to a lack of full coverage of flare sites and/or underreporting from sites for which data are reported.

Gas flaring provisions in EIA

Flaring and venting is addressed explicitly in EIAs only within the context of local environmental protection and worker safety, rather than in relation to flare reduction's role in achieving better national energy resource use and climate protection. However, this does not mean that flaring as a resource management problem is not addressed in investment decision making processes of joint ventures, but rather that there are no references to explicit legal and regulatory provisions in this regard (Carbon Limits, 2016). More informally, EGPC have instituted requirements for when flaring is acceptable. While there are no official or legal permits for gas flaring, an upper limit of 1 mmscfd has been announced by EGPC, albeit not officially, for flaring at gas-condensate fields. However, its implementation is not monitored or otherwise followed up on regular basis by EGPC. Although such an upper limit is not applied in the case of oil fields, it is understood that EGPC puts pressure on operators to find solutions for associated gas, but that acceptable flare levels are higher for oil fields and considered more on a "case-by-case" basis than for gas condensate fields, most likely for the reason that the resource waste in relative terms is much larger in the latter case.

2.4.3 Flare reduction investment approval process

As described in Section 2.4.2, EGPC effectively grants operators permission to flare gas in the context of the EIA approval process. EGPC also approves gas utilisation investments, including appraisal of its own projects. There is however no clearly defined and publicly available process and/or specific set of rules that need to be followed by operators for APG flaring reduction investments in Egypt. Specific economic tests or other defined appraisal approaches for making such investments do not seem to be used on a formal basis. However, it is understood that to date, the capital costs of most APG flaring reduction

¹⁵ *Regulation of Associated Gas Flaring and Venting: A Global Overview and Lessons from International Experience*. Global Gas Flaring Reduction Public-Private Partnership, World Bank Group, 2004.

¹⁶ See: www.ngdc.noaa.gov/eog/viirs/download_global_flare.html.

projects implemented in Egypt have been covered under the cost recovery terms within the PSCs – where these have been proven to be cost effective and technically viable. One such example was a project to invest in LPG extraction and gas injection at the Zeit Bay field in the Gulf of Suez in 1983, which was successfully financed and constructed by the foreign partners of the JV Suez Oil Company (Shell, BP and Deminex) under the PSC’s cost recovery terms. The project had a total budget of around US\$ 250 million (US\$ 1983), with the investment being fully recovered through the cost recovery pool from oil sales.¹⁷

However, financial difficulties faced by EGPC over recent years have meant that they have often been unable to contribute to the costs of investments to reduce flaring, even where considered economically attractive. Investments in flare reduction must compete with other EGPC projects, and compared to oil production expansion investments gas flaring reduction is not prioritised. Furthermore, it is typically easier to have funds allocated for gas utilisation investments when they are part of new field developments than flare elimination investments from existing producing fields, particularly if such fields are in decline and have limited remaining economic lifetime (Carbon Limits, 2016). In some cases, the capital costs required for flare reduction projects in Egypt have been covered totally or partially through International Finance Institutions loans, as in the case in the Kuwait Energy Company (KEC) APG flaring reduction project which is being considered for a US\$ 40 million loan provided by the EBRD. In contrast, during the 1980s, APG flaring reduction projects in the Gulf of Suez area were directly financed by EGPC.

Investments in flare reduction projects are also facing some more generic investment approval challenges. For example, it is understood that operators face major administrative hurdles for CAPEX approvals and permit applications. Additionally, it appears that operators are not clear as to whom they need to contact and at what stage of the application procedure. This makes the approval process slow and bureaucratic, and acts as disincentive for possible investments in APG flaring reduction. There is therefore significant lack of transparency and clarity around the investment process, including the relevant roles and requirements across the project investment cycle.

2.5 Institutional framework

2.5.1 Key entities

At the strategy and policy level, Egypt’s energy sector is managed and guided by the regulations and directions issued by the Supreme Energy Council (SEC). The Ministry of Petroleum (MoP) oversees policy development and implementation for the oil and gas sector. Its functions include the preparation of legal and regulatory amendments to be put forward for resolution by the Parliament and the President, and the preparation of concession agreements for ratification. Key state entities under the Ministry include:

- o **Egyptian General Petroleum Corporation (EGPC)** established in 1956 to manage upstream activities including infrastructure, licensing and production. EGPC also owns and operates much of the country’s refining capacity. Since the 1960s, EGPC has formed joint ventures with a growing number of international

¹⁷ Source: Eng. I.Saleh, Former Executive Director, EGPC.

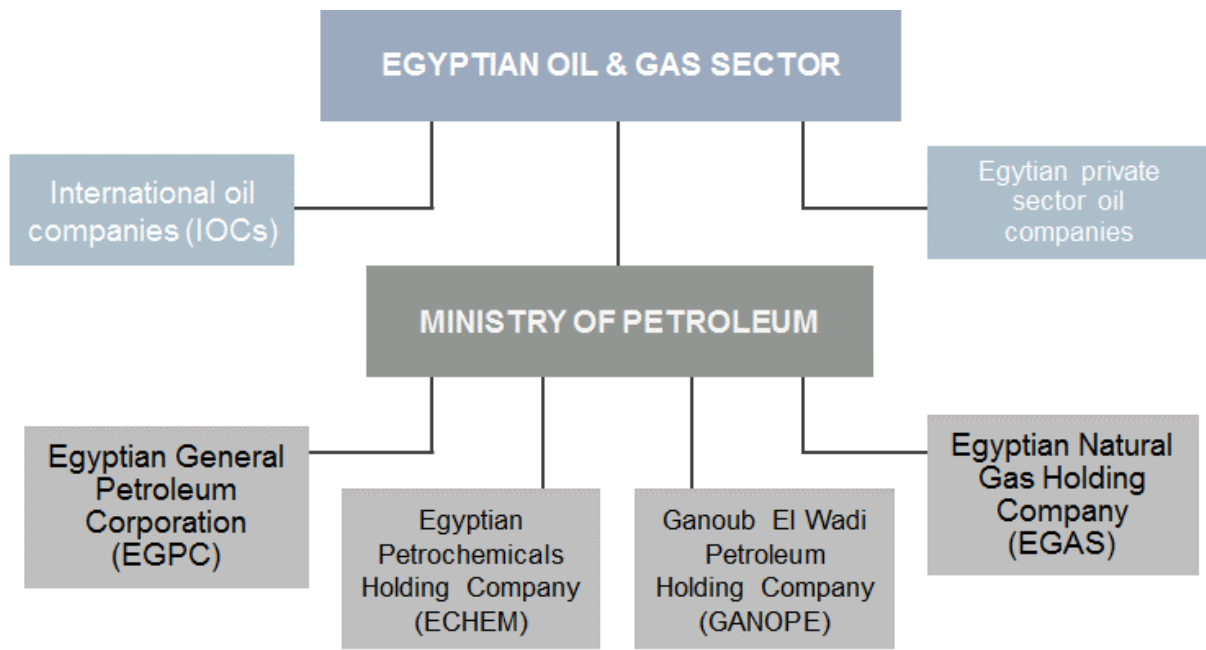
oil companies (IOCs) in the upstream sector on a production sharing basis. EGPC has established upstream license conditions, including Production Sharing Contracts (PSCs). As noted above EGPC also acts as the main regulatory entity for upstream gas flaring and venting.

- o **Egyptian Gas Holding Company (EGAS)** established in 2001 to oversee the development, production and marketing of natural gas. EGAS is responsible for organising international exploration bid rounds and awarding gas exploration licenses, and participates in joint ventures with IOCs (and sometimes with EGPC) to develop and operate gas fields. EGAS acts as single buyer of gas for the regulated tier of the market.
- o **Egyptian Petrochemicals Holding Company (ECHEM)** established in 2002 to manage and develop the petrochemicals holding company in Egypt.
- o **Ganoub El Wadi Petroleum Holding Company (GANOPE)** established in 2003 to oversee oil exploration and production in southern Egypt (upper Nile region). GANOPE plays a similar role as EGPC in its area of operation. It also acts as gas flaring regulator in the upper Nile region upstream operations.

Accordingly, the oil and gas sector currently consists of four major entities cooperating and integrating to make the best use of the country's hydrocarbon resources. Figure 9 illustrates the main entities playing an active role in the sector. EGPC, EGAS and GANOPE all have management and regulatory functions related to exploration and development licenses and PSCs, as well as being commercial partners in joint ventures.

The extraction of oil and gas is regulated by the Egyptian Mining and Quarries Law 86 of 1956 and the terms and conditions set out under the relevant concession agreements. Oil and gas concession agreements are awarded to IOCs or NOCs by a bidding process: EGPC undertakes bidding rounds for exploration licenses mainly in the oil-producing Gulf of Suez and Western Desert, while EGAS mainly covers the Nile Delta and GANOPE the relatively undeveloped southern region.

Figure 9 Institutional structure of Egyptian oil and gas sector



Source: authors

Besides MoP, the **Ministry of Environment** also plays a role in the running of the energy sector in Egypt. Specifically, the **Egyptian Environmental Affairs Agency (EEAA)** acts as the regulating authority for environmental issues, responsible to the Ministry of Environment. The EEAA has the power to set criteria and conditions, monitor compliance and to take action against violators of these criteria and conditions.

2.5.2 EGPC and EGAS

EGPC is the dominant state-owned entity in the upstream oil sector. It is responsible for managing the oil industry in Egypt with activities covering petroleum agreements, exploration, production, transportation and refining. The Egyptian government, through EGPC, owns or partially owns a large group of companies. In addition, all of Egypt’s refineries are run by EGPC subsidiaries. As a controller of the industry, any private investments in Egypt must take the form of a joint venture with EGPC supervised by the government. Since EGPC is the primary state-owned subsidiary involved with exploration and development of Egypt’s oil fields, it is also the principal institution dealing with flaring and utilisation of associated gas (Carbon Limits, 2016).¹⁸

EGPC’s dual role of gas flaring and venting regulator as well as joint venture partner in upstream operations creates a conflict of interest. Its officially stated objectives include (i) maximising oil production and enhance oil reserves, (ii) satisfying local demands for petroleum products and (iii) maximising petroleum exports revenues¹⁹. These objectives can run counter to gas flaring reduction investments, which can risk a temporary shutdown in

¹⁸ Associated Petroleum Gas Flaring Study for Egypt. Carbon Limits, 2016.

¹⁹ Other objectives are (i) upgrading oil refineries efficiency to maximise high quality petroleum products, (ii) optimising utilisation of existing infrastructure, (iii) applying the latest technologies used in the oil industry; and (iv) applying international high standards and measures.

oil production while the necessary engineering work is undertaken. Additionally, the commercial incentives for such investments are not clear as described in section 2.

EGAS was established as a part of an action plan to reorganise and handle the activities related to natural gas resources for providing additional value to the Egyptian economy. Its main objectives and function include the following:

- o Encourage investments in natural gas activities
- o Participate in exploration, development and production of natural gas
- o Continue issuing bid rounds and signing concession agreements
- o Manage sales through gas transmission & distribution systems and coordinate all related activities.
- o Develop LNG projects individually or with national and international partners.
- o Expand the natural gas grid and the use of natural gas in different sectors

Since 2004, all new gas concessions have generally been allocated to EGAS whilst older concessions continue to be maintained by EGPC. Major reforms to the natural gas sector are currently underway with the development of the draft New Gas Law (see section 2.1.3). The Law is expected to be passed in 2016 and has implications for the supply of associated/utilised gas into markets - and also the changing roles of EGAS. The Law contains provisions to liberalise the gas market and encourage greater competition in the sector, including the ability for market players other than EGAS and EGPC to sell both domestic and imported gas directly to consumers using EGAS transmission infrastructure.

As part of these changes, the Law establishes a new Gas Regulatory Affairs (GRA) authority to regulate, monitor and ensure the competitive and transparent functioning of the gas market, including the issuing of licenses to new companies and regulating tariffs. Thus the Gas Law sees a transfer of some of the activities previously undertaken by EGAS and EGPC. However, as stipulated in the draft New Gas Law, GRA is focused on mid and downstream operations and will therefore not cover upstream operations and gas flaring regulation. The primary regulatory responsibility is therefore likely to remain with EGPC.

2.5.3 Licensing for exploration and development

International bidding rounds for exploration and development licenses are structured around different phases. For the exploration phase, the contractor company signs a concession agreement with EGPC, EGAS or GANOPE; there are several bidding parameters, most notably specifications around work commitments, profit sharing and signature bonus. Concessions must be approved by Parliament and signed by the Egyptian Minister of Petroleum and the contractor.

In general, the term for exploration ranges from seven to nine years, divided into three terms: the initial term and two extensions. However, if there is a commercial oil and gas discovery, the term may be set at 25 years to be extended to 35 years. In this case, a PSC is negotiated and a joint venture is established between the contractor (i.e. an IOC) and EGPC,

EGAS or GANOPE requiring they take at least a 50% stake. All costs are borne by the contractor.

In general, the concession agreement provides the contractor with the right to sell and export its entire share of the oil and gas produced, as determined by the terms of PSC. However, EGPC, EGAS and GANOPE have the right of first refusal to purchase the oil and gas to meet domestic needs. Another important feature of many PSCs is that recovered associated gas only belongs to the joint venture if it is used on site, otherwise it is for EGPC, EGAS or GANOPE to decide on its utilisation. Operators thereby have no ownership over any associated gas produced, offering poor incentives to companies to invest in gas utilisation projects. They do however receive a share of the excess gas in line with the profit split.

There are no explicit gas flaring permitting procedures in Egypt. As part of the licences development, operators are required to provide a field development plan, which should include an associated gas management and flaring reduction programme. As noted above, a nominal cap of flare volumes is specified in the development licences. However it is not strictly enforced by EGPC.

3 Constraints to gas flaring reduction investments

This section sets out the major constraints we identify with the existing gas flaring regulatory framework, or lack thereof. We structure the section along the following main components:

- o Constraints identified in the *PSC terms*
- o Constraints in the *current regulatory set-up*
- o Constraints related to the *wider market conditions for gas in Egypt*
- o Constraints related to *the institutional structures governing gas flaring*

3.1 PSC constraints

The standard PSC, by and large, is suitable for financing projects of APG flaring reduction for immature fields with favourable technical parameters (gas/oil ratio, reserves size). However with ageing fields, limited funds for recovering the cost of flare reduction projects, and relatively small and dispersed flaring volumes, investment becomes more difficult under the existing PSCs. This means that the existing PSC terms in general are not well suited for the changed petroleum production landscape in Egypt. We list a number of constraints below; however these are exclusively relevant for gas flaring investments but instead show that the general terms and conditions of PSCs could represent a constraint to additional investments in certain conditions, e.g. small production volumes or low hydrocarbon prices. This is due to the fact that gas flaring investments have no explicit component in the PSCs. The main deficiencies in the existing PSC terms that affect investment decisions (including gas flare investments) are:

- o **Risk of non-recovery of costs** - The cost recovery mechanism in the PSCs may expose upstream producers to significant downward oil price risk, which would act as a disincentives for additional investments. If for example in any quarter, hydrocarbon prices are low, a larger quantity of product would need to be allocated to cost recovery. This would mean that there is a higher likelihood that the cost recoverable in that quarter exceeds the maximum ceiling of production as specified in the PSC, say 30%. The additional cost would be carried forward to the next quarter; however its recovery is not guaranteed, as the 30% ceiling equally applies in that quarter. Hence, over a prolonged period of low hydrocarbon prices, upstream producers could accumulate a significant volume of costs that might never be recovered over the lifetime of the fields. Although part of this cost can recouped through the profit split (see below), it does represent a strong disincentive to invest, especially for fields with marginal production and/or investments yielding small additional production volumes. This risk can be mitigated in practice as in most cases contractor(s) will renegotiate gas price terms based on changes in exploration and development costs.

- o **Investment decisions for EGPC and contractor not aligned** – The contractor will want to recover any investment cost as early as possible and minimise any upfront capital expenditure. The contractor would for example prefer to rent equipment, so that this cost is treated as operating expenses, which is considered a recoverable cost and can be recovered in the same quarter as it is incurred. EGPC as the ultimate owner of any fixed assets at the facility, however will want to push the contractor to invest in large capital on equipment and pipelines rather than renting equipment²⁰. The delay of cost recovery²¹ or worst still the risk of non-recovery (see bullet point above) mean that the contractor has little incentive to make these types of large investments. This conflict of interest makes for protracted negotiations between the upstream partners for any investment decisions resulting in sub-optimal investment decisions and levels.
- o **Cost approval process is difficult and time consuming** – Contractors face lengthy and difficult processes for approval of the costs to be included as part of the recoverable costs. According to the declared principles, costs should be included for items in the approved development plan after a transparent bidding process and the selection of the most economically advantageous offer for investment items. However, inevitable changes occur during implementation which may require rental of equipment to expedite the process for a while or change the plan altogether. This can result in disagreements between partners and can lead to the exclusion of some cost items from the ‘recoverable cost component’. For investments in APG flaring reduction, which often are barely economical, this administrative constraint can act as a major disincentive to invest. Creating clearer guidelines on the costs that can be recovered from any APG utilisation investment could partially alleviate this constraint.
- o **EGPC not complying with PSC payment terms, creating investment uncertainty** - As a result of becoming a net importer of hydrocarbons since 2014, and facing slower economic growth as a result of the 2011 political upheavals, Egypt and EGPC have faced foreign exchange reserve impasses. This had a significant impact on investment decisions for upstream operations including APG flaring reduction investments. Firstly, it resulted in delayed payments from EGPC to contractors for their hydrocarbon share and, secondly, payments were made in EGP and not in US\$ (under PSC terms, delayed payments trigger a penalty, although this was never enforced). This has given rise to concerns around contract sanctity in Egypt’s upstream sector, and has accordingly impacted on overall investment levels. While this is not a constraint of the PSCs per se, it demonstrates that the implementation of PSCs (or lack thereof) acts as a constraint to investment.

The constraints identified in the PSC terms highlight the fact that the existing regime is not best suited to APG flaring reduction. No explicit gas flaring investment clauses exist and consequently, all constraints identified affect all investments, not just gas flaring investments. Changing the entire cost recovery mechanism and all PSC terms just for the purpose of gas flaring reduction seems excessive and unrealistic. Implementing such changes can be lengthy and cumbersome requiring extended negotiations, legal proceedings

²⁰ Although this will depend on the residual values and the decommissioning costs of these assets.

²¹ CAPEX is recovered over a five year period as opposed to OPEX which is recovered as incurred on a quarterly basis

and parliamentary approval. This suggests that PSC reform might not be the first best short term solution to address gas flaring in Egypt. Furthermore, we identify more significant constraints that can be rolled out more quickly with greater impact in the remainder of this report.

3.2 Regulatory constraints

The regulatory constraints, or the major aspects lacking in the existing framework for successful regulation, include:

- o **Unclear and non-transparent metering or measurement provisions** – As noted above, the reporting requirements for operator’s gas flaring levels are not clearly defined. For gas flaring levels to be reduced and any site specific gas flare reduction measures to be implemented, there has to be certainty regarding the levels of APG flaring. This could be done through two approaches: first, through the gas flow meters or the ultrasonic measuring devices; second, through estimates made on measurements of produced, processed, utilised in site and pumped gases to the national gas network (“by-difference” approach). The latter is the most preferred option for Egyptian gas operators. With no measurement method agreed, or imposed through guidelines, reporting is based on measurements that are not consistent or transparent, especially since the dominant estimation method is less accurate.
- o **Deficiencies in monitoring and evaluation process** – The lack of a standardised approach/methodology for the measurement of gas flaring leads to inaccuracy in reporting and consequently difficulties in monitoring and evaluating APG flaring levels. There is currently no clear system in place for how monitoring and evaluating of flare levels should be performed. Consequently, EGPC only sporadically performs this function and when it does, it is not clear what process it follows. This may be related to the lack of investment in equipment or human resources in this respect, which could be a direct result of (1) the lack of announced flaring policy; (2) the knowledge that for most of the wells/fields the ceiling set for flaring is not implementable; and (3) the lack of incentive to enforce this ceiling given its impact on oil production.
- o **No gas flaring permits** – Issuing flaring permits is a regulatory tool which gives operators of oil and gas producing companies the right to flare specific volumes or quantities of APG and is applied either for new or existing oil and gas facilities and installations. In all jurisdictions with successful gas flare reduction regulatory frameworks, a fundamental component is the permitting procedure and system. There are no formal permits for APG flaring in Egypt. Flaring permits specify the volume of allowed gas flaring levels and are allocated on the basis of the nature of flaring at the site, the volume of flaring and economic viability of gas flare reduction investments. They set the benchmark against which any operator is considered compliant with flaring regulations or not. Without permits, operators do not know what their allowed level of flaring is and consequently are not incentivised to invest in flaring reduction.

The lack of gas flaring permits means that operators do not know in any year what level of flaring is acceptable or not. They will also have no information on the volumes and instances of flaring for safety or maintenance reasons. This can be specified in the flaring permits and can be used as a guide for upstream operators to regulate flaring and/or invest in the necessary infrastructure.

- o **No consistent enforcement of maximum flare volumes** – As noted previously, the oil production lease specifies a maximum volume of 1 mmscfd per producing field. Unlike an annual permitting system, this flat ceiling is not site specific and cannot be changed regularly by taking into account changes in external parameters (e.g. price changes, prior gas flare reduction investments, technical feasibility of gas flare reduction on site). Consequently, EGPC is likely to apply different criteria to different sites in their application of the flat maximum flaring level. These criteria are not transparent, however, and therefore cannot provide sufficient guidance to operators to reduce their gas flaring volumes. Additionally, the ceilings are not enforced by EGPC due to the policy and financial conflict of interest of EGPC’s dual role as regulator as well as commercial partner in upstream operations.
- o **Lack of clear penalties for flared gas** – Any regulatory regime requires enforcement mechanisms. These can take the form of one-off penalties, lower prices, forced oil production shut-in or forced investments in gas flare reduction equipment. There appears to be a complete lack of any of these in Egypt. This leads to the question of how EGPC could regulate gas flare volumes and gas flaring reduction if it was to act as the APG flaring regulator.

As described previously, there might be informal procedures that EGPC can apply to contractors if not compliant with the informal flare limit; however this is not transparent and producers may feel that this is applied either arbitrarily or depending on external (policy) factors. This does not provide the necessary incentives to invest in gas flare reduction assets. Instead it leads to an uncertain and non-transparent process, which will dis-incentivise contractors to make significant investments.

- o **No field specific economic or technical factors considered** – The poorly implemented flaring limit specified in the oil development lease, even if it would be implemented, applies as a default level across all fields. This means that no site specific considerations are being made in the gas flaring reduction approach. It may be that EGPC takes field specific factors into account when enforcing these limits; however these are not transparent and formalised. This provides uncertainty for an upstream developer on the type and level of flaring allowed in future.

Successful regulatory frameworks are sufficiently flexible to allow for field specific factors to be included in regulating gas flaring levels. This is evidently not the case in Egypt. Setting flare limits on a robust feasibility for utilisation to tailor the flaring ceiling according to specific well/field conditions would represent a better basis for an enforceable permit reflected in the development plan.

An appreciation of the economic value of APG currently being flared is a necessary condition for a successful regulatory regime, followed by an announced policy, a master plan for APG flaring reduction and enforcement of permits based on specific feasibility.

- o **Focus on pollution in the Environmental Impact Assessment (EIA) Process** - In its review of EIA applications, the environmental regulator (EEAA) focuses on the quality of emissions resulting from flaring in terms of pollution concentration. A balanced focus on resource conservation, requesting that the APG volume flared be justified in the EIA application, could become a good trigger for companies and EGPC to consider the feasibility of APG utilisation. This may not be a constraint proper, but rather an effective use of an existing tool that could help improving APG utilization.

Although there are attempts to control APG flaring, an integrated regulatory regime for flaring and venting reduction is missing. This has led to (i) a lax implementation of unofficial flaring level ceilings; (ii) unclear enforcement and reporting mechanisms; (iii) an uncertain investment environment and (iv) oil production volumes being prioritised over gas flare reduction efforts. Overall, the existing flaring framework lacks transparency in its processes, implementation and requirements. A regulatory framework supported by secondary legislation is needed to give operators the clarity to implement gas flaring investments.

An integrated regulatory regime would help settle a number of key issues to clarify process and procedures, which include:

- o the definition of the relevant activities accompanied by gas flaring and identification of its relevant boundaries (continuous or routine flaring that could be reduced through projects and intermittent flaring that could be reduced through operational practice);
- o economic evaluation of the feasibility of implementing APG flaring reduction projects;
- o regulatory approval, and permitting of APG flaring, based on a site specific feasibility study;
- o methodologies and procedures for the measurements of APG flaring, Monitoring, Reporting and Verification (MRV) activities; and
- o enforcement of permits.

The responsibility to manage and ensure the proper operation of this regulatory regime will need to be allocated. As the oil sector lacks the existence of an independent Oil Regulatory Authority and regulatory functions are currently undertaken by EGPC, this responsibility would initially have to be performed by one of EGPC's relevant divisions/ departments.

3.3 Wider investment constraints

Gas flaring levels are most efficiently reduced when it is economically viable for agents to do so. Oil and gas producers will reduce flaring by either marketing, or reinjecting APG on their own volition if it is profitable to do so. One important aspect to consider when identifying wider incentives is the composition of APG, as different incentives will apply to different APG compositions and therefore utilisations. In Egypt, APG is typically rich gas and sending it to customers through the gas network to be burned would be a worse use of the resource compared to extracting heavier and more valuable components first through processing. The constraints of wider incentives we identify below apply in general. Any regulatory framework to be developed for Egypt however needs to be flexible enough for operators to identify the usage of gas that is the most economically viable.

Under the current gas market arrangements in Egypt, the following constraints to wider incentives can be highlighted

- o **No third-party network access** - Non-discriminatory TPA is not yet in place in Egypt, which is an obstacle for operators seeking to access the transmission network. Without access to the network, operators cannot freely choose which entities to sell the gas to and therefore cannot select the highest paying or indeed most creditworthy offtakers. Exceptions could be provided for APG before TPA is more widely enacted under the new gas law or the Government could more actively assist in setting up bilateral or multilateral agreements for transmission line access.
- o **Single buyer regulated market prevents market price mechanisms to emerge** - the single buyer market model means that producers can only sell gas to EGAS. This monopsony situation leaves upstream producers little room for negotiations and exposes them fully to the creditworthiness of EGAS. Combined with low regulated prices, in retail gas markets, upstream producers have little chance to obtain market reflective prices for captured associated gas. This acts as major constraint to investments. Under an open market with non-discriminatory access to transmission pipelines and operators and offtakers entering bilateral contracts, operators would receive market prices for their APG utilisation investments and crucially could enter into negotiations with offtakers. Depending on the technical features of the oil and gas fields, this may result in a more secure supply stream. This may be valued by some users, who could be willing to pay higher prices.

In a bid to relieve the financial and supply pressure on EGAS, consumers are already allowed to directly contract LNG imports. A similar exception could be provided for APG, with consumers being able to directly contract with operators for gas that otherwise would have been flared. This could also encourage private sector participation and partnership in gas flare reducing investments, given consumers would directly benefit from securing APG as supply, particularly with gas supplies being so strained in Egypt today.

- o **Dependence on gas offtake from the subsidised power sector** - EGAS' revenue is heavily dependent on the high volumes demanded by the power sector. Despite gas prices for the power sector being raised from \$1.1/mmBtu to \$3/mmBtu in July 2014, the power sector is still heavily subsidised given the

rising average cost of supply (let alone the marginal cost of supply from LNG imports). This has been a primary contributor to EGAS' financial instability and will remain to be the case until regulated prices are more directly linked to the cost of gas supply or market opening takes place for gas supply to the power sector. Operators will be less incentivised to capture gas when it must be sold to a financially at-risk offtaker.

- o **'Natural' constraints due to the inherent nature of Egyptian gas flaring** - The physical geography of gas flaring in Egypt will be an ongoing difficulty in reducing flaring levels. As Figure 2 illustrates, flaring in Egypt is characterised by a scattering of 73 flaring sites at relatively small absolute volumes rather than being concentrated at a few select sites. Flaring reduction is much easier to achieve if the majority of flaring is occurring at a few high-volume sites where infrastructure is easier to coordinate and economies-of-scale can be had. Instead, Egypt is faced with numerous, small volume flaring sites, which may in turn require multiple, small-scale infrastructure investments, hurting the economics and coordination of a large-scale investment program.
- o **Domestic gas prices too low** - A primary factor in whether an operator would seek to market APG rather than flare it is the price they would receive for the gas. Therefore, a significant constraint to reducing gas flaring is Egypt's low domestic gas prices. Better terms have been offered to operators as the supply crunch has become more acute, with Eni being paid \$4-\$5.88/mmBtu for its Zohr field,²² but many fields are still operating under older PSCs that were signed in an era of low-cost Western Desert, Delta, and Gulf of Suez onshore fields.
- o **No additional investment incentives for APG flare reduction** - there are no explicit incentives for associated gas utilisation, such as a different pricing mechanism, tax breaks on APG investments or favoured access to the transmission grid. Associated gas is treated like non-associated gas, which can be justified if occurring in large volumes; however the small APG volumes scattered over a large number of sites, means that the economics of APG could be improved by creating a favourable regulatory framework.
- o **Awareness of gas flare reducing projects** - In recent years, a small number of successful flare reduction projects have been implemented in Egypt, one of which involved an EBRD loan to Kuwait Energy. Unless these successes are well-publicised, other operators may perceive reducing gas flaring as technically-prohibitive or not worth the effort. The GoE could use these projects to demonstrate: (i) the process of application for such investments; (ii) the financial benefits to operators from such investments. Ideally, this should be done by establishing an upstream stakeholder association and scheduling regular workshops showing demonstration projects.
- o **Lack of government policy on gas flaring and venting** - Our preliminary assessment and discussions suggest that the Government of Egypt (GoE) is keen to reduce gas flaring levels. This is not surprising given that reducing gas flaring is an undeniable positive. However, there is no official policy in place on gas flaring reduction. No flare targets, institutional provisions, or implementation

²² Eni to complete second well in Zohr field by April for 100m, Daily News Egypt, 10 February 2016

roadmaps have been developed as part of a long-term gas flaring strategy. Establishing a policy goal would demonstrate clear political commitment and set a framework from which regulations should operate.

If the changes proposed in the draft New Gas Law materialise, they are likely to have a significantly positive impact on APG flaring reduction investments. Although by no means sufficient in their own right to reduce gas flaring levels, the provisions will provide the following incentives:

- o **Contractors free to choose offtakers** - with the opening up of an unregulated market, contractors could select their preferred consumer. This could be based on their willingness to pay, their creditworthiness, their location and their demand volumes. Together these could be used as a bargaining mechanism for contractors to achieve higher prices and not be fully dependent on one single buyer, EGAS.
- o **Less dependence on EGAS and power sector demand** – currently, investment decisions for gas utilisation are closely linked to power sector changes: EGAS as the single buyer is highly dependent on payments from power generators (as these constitute the majority offtake), which in turn are highly dependent on electricity price changes.²³ As EGAS has faced financial difficulties and subsidies prevail in the electricity sector, upstream gas investments are not attractive. By being able to select other consumers to whom to sell to, contractors will have more of an incentive to utilise gas.
- o **Cost reflective prices could emerge as a result of negotiations** – low domestic gas prices are a major factor in dis-incentivising APG utilisation investments. An unregulated market would allow eligible customers to price-in security of gas supply and therefore pay prices above the current low tariffs.
- o **Higher prices will have positive impact on cost recovery** - the resulting higher gas prices negotiated on the basis of bilateral contracts could have an impact on the cost recovery mechanism as well. It is not yet clear how these prices would be included in the cost recovery procedures. However, if it does get included in the cost recovery mechanisms, there could be a lower likelihood that the cost recovery cap (in terms gas production) would be reached. Consequently, the major constraint identified in the PSCs, namely the risk of under-recovery of costs, might be overcome. This is speculative however, as the exact mechanism of how bilaterally negotiated prices will be included in the cost recovery mechanism is uncertain at this juncture.

3.4 Institutional constraints

Whilst environmental protection and increased use of domestic hydrocarbon resources are both stated national policy objectives, the reduction of associated gas flaring is not currently reflected in Egypt’s institutional framework.

²³ As part of the July 2014 energy subsidy reforms, the Egyptian Government announced it would phase in a doubling of electricity prices over five years, with targeting of high electricity users.

There are no specific laws or regulations in respect of gas flaring and venting, except general safety and health regulations which include permitted levels of atmospheric emissions from oil and gas sector installations. In practice, these have little influence on current flaring practices and gas utilisation investments. Gas flaring reduction is instead overseen on an informal basis, typically as part of the EIA approval process for new projects.

As such, there is a lack of transparency and clarity regarding specific roles, processes and requirements within relevant institutions. It should be noted that notwithstanding opportunities for increased supply of natural gas, the forthcoming reforms under the new Gas Law do not foresee any institutional changes in the gas flaring oversight. Notably, the activities of the proposed GRA activities are limited to mid- and down-stream regulation and exclude upstream activities (gas exploration, development and production).

Several specific institutional constraints can be identified, contributing to gas flaring reduction investments not taking place in Egypt:

- o **No clear assignment of responsibilities for gas flaring within existing framework** - The institutional structures of EGPC, EGAS and GANOPE do not include any units or divisions directly involved with, or responsible for, gas flaring reduction policy. These entities therefore lack an effective framework for the implementation and management of flare reduction, with clearly defined roles and responsibilities. The only units which exist within the present institutional structure of these organisations with indirect oversight of gas flaring are the environment divisions; these are however mainly responsible for handling and managing the different health, safety and environment aspects and activities related to the oil and gas industry, and these do not explicitly address gas flaring reduction above and beyond the permitted levels of combustion emissions. In practise, EGPC acts as the principal institution dealing with flaring and utilisation of associated gas, including supervising flare levels and deciding whether or not gas should be utilised as part of new oil development projects. However, whilst EGPC has much of the capabilities required for enabling flare reduction policy, particularly in relation to the assessment of technical and economic challenges of flare reduction investments, its mandate is not clearly or formally defined, and the scope of activities and procedures are not transparent.
- o **No designated independent flaring regulator** - As described above, EGPC has the main responsibility in Egypt for supervising gas flare levels, although this is not formally determined. International best practice however shows that self-regulation should in general be avoided – given the potential conflicts arising between commercial objectives and the objective of minimising unnecessary flaring. An oil company with a mandate of combining commercial and regulatory functions is not viewed as best practise internationally; an effective regulatory agency is one that operates independent from state oil companies, instead located under an appropriate ministry or independently. More specifically, the lack of separation of regulatory and operational responsibilities between an independent agency and a national oil company creates a conflict between the goals of increasing oil production and reducing flaring, which can give rise to conflicts of interest. Firstly, as a government owned and controlled entity, EGPC is unlikely to act independently of the wider hydrocarbon policy that might adversely affect flare levels adversely. Secondly, as joint venture partner in almost all upstream operations, EGPC could prioritise other sector

objectives - potentially running counter to gas flaring reduction - over the reduction of gas flaring levels.

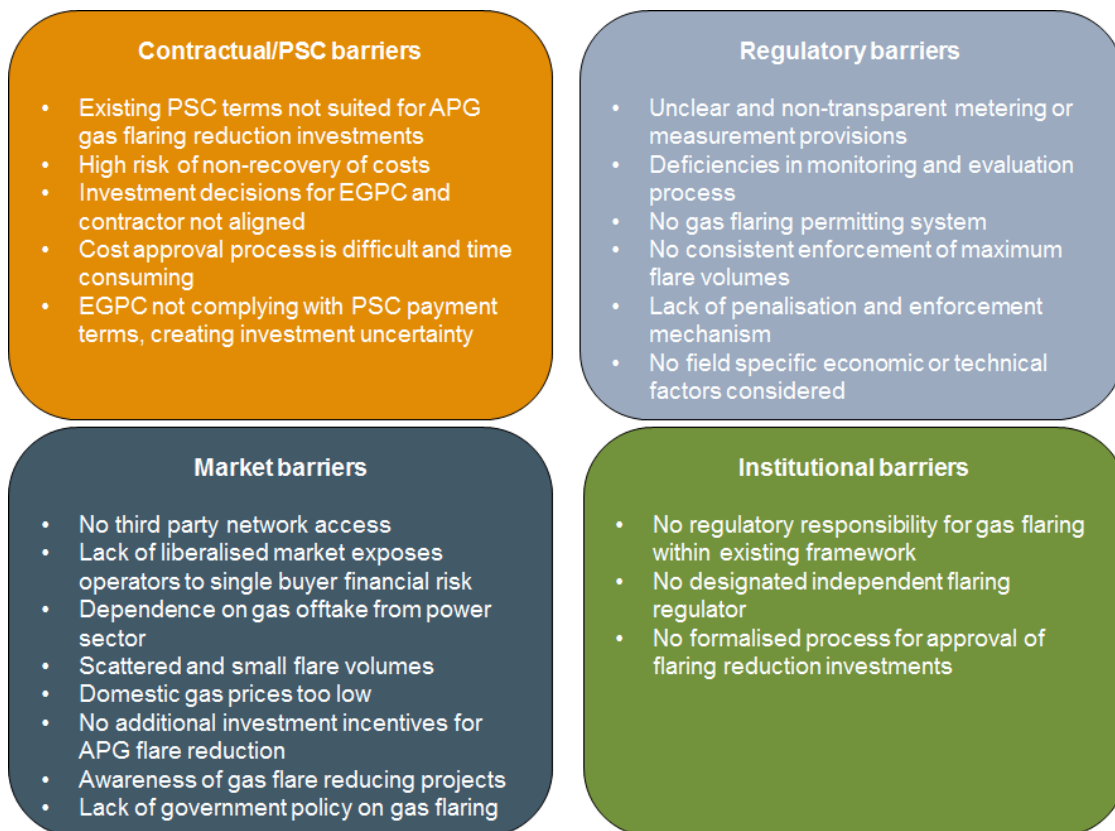
- o **No formalised process for approval of flaring reduction investments** - There is at present no formal, clear and transparent governmental investment process and procedures for the approval of APG flaring reduction investments. Currently, operators face major administrative hurdles for CAPEX approvals and permit applications. Additionally, it appears that operators are often not clear as to whom they need to contact and at what stage of the application procedure. This makes the process slow and bureaucratic and acts as a disincentive for possible investments in APG flaring reduction. It is typically easier to gain approval for funds allocated to gas utilisation investments when they are part of a new field developments rather than flare elimination investments at existing producing fields, particularly if such fields are in decline and have limited remaining economic lifetime. To facilitate investments in APG utilisation, the Egyptian government therefore needs to establish a clear, transparent and efficient process for investment appraisal.

3.5 Summary of constraints

The main constraint for investment in gas flaring reduction is the marginal economics of APG utilisation projects. This was presented in detail in the previous EBRD funded study and is largely due to low gas prices, small and scattered volumes of gas flares, and high capital expenditure requirements for such investments. Consequently, only a small number of associated gas utilisation projects have been realised in Egypt over the past decade.

The current market and policy conditions in Egypt are therefore not adequate to bring gas flaring levels down and provide crucial new gas supply sources for Egypt. Hence additional incentives are needed if gas flaring levels are to be reduced. The previous sections identify the main constraints in the existing policy, regulatory, institutional and contractual frameworks preventing such investments to take place. The constraints are summarised in Figure 10.

Figure 10 Main constraints to gas flare reduction investments



It is difficult to determine objective criteria to rank the constraints identified by severity and their individual impact on gas flaring. From our findings and stakeholder consultations however, we can make a qualitative assessment of the main constraints to gas flaring reduction investments, as outlined below.

Constraint 1: Lack of a transparent and well defined regulatory framework supported through secondary legislation

While some arrangements exist for gas flare limits and oversight responsibility, these are not formalised in secondary legislation creating uncertainty and lack of transparency for operators. Consequently, these measures do not result in operators prioritising gas flare reduction investments. The following key components of the regulatory framework (not covered in other constraints in this section) are the major contributors to Egypt’s gas flaring levels:

- o No formally *approved and transparent maximum flare level* in the form of a target or site specific permitted flare volume and flare type. A flat maximum flare limit is in place in gas sales agreements – this system is not flexible enough to accommodate for changes of external parameter affecting gas flare reduction investments;
- o No *gas flare permits system* that could create direct accountability and set flare limits for operators. These permits could also set conditions under which gas flaring is allowed (small filed, safety, temporary, if economic or technical case not clear).

- o No *penalisation and enforcement mechanism*, creating uncertainty among operators regarding the consequences of non-compliance. This also prevents EGPC to issue credible threats to non-compliant operators.

Constraint 2: no transparent monitoring, evaluation and validation process to ensure flare levels are within allowed quota

Although operators are currently required to report gas flare levels to EGPC on a daily basis, no guidelines or requirements are in place that ensure consistent and accurate measurement. There is currently no methodology or formula prescribed to operators for measuring gas flaring levels. There are equally no minimum technical standards that need to be met for measuring/metering volumes of flared gas. Lastly, there is no publication of data on levels of gas flaring; this would allow for direct comparisons/benchmarking across different fields and operators.

Constraint 3: insufficient ‘pull factors’ and economic incentives to improve the economics of gas flare reduction projects

Whilst the regulatory framework can be considered a ‘push factor’, economic incentives can act as pull factors incentivising investments for operators. These may not be directly linked to gas flaring, but have a significant impact on investments to reduce gas flaring²⁴. In particular, these include:

- o *No wholesale market mechanism to ensure gas prices are cost reflective*. Gas is bought from producers by a single buyer, EGAS, on the basis of prices determined in GSAs. This means that operators have little room for negotiating prices on the basis of supply demand conditions. Simultaneously, retail prices are regulated and set at levels that are far below cost recovery for EGAS. This leaves operators fully exposed to the creditworthiness of EGAS and means that wholesale prices are not considered sufficiently high to recover additional investment costs.
- o *No third party access arrangements*. By forcing operators to sell gas to the single buyer, market mechanisms and price adjustments are prevented. Opening the market and allowing operators to negotiate gas sales agreements with offtakers directly would incentivise operators to reduce gas flaring levels.
- o *High dependence and risk from power sector, which is highly subsidised*. The power sector makes up the largest share of gas demand in Egypt; however its prices are heavily subsidised. This amplifies the uncertainty of EGAS’s cash flow position and therefor dis-incentivises gas flare reduction investments. A more cost reflective electricity price regulation could provide more certainty for upstream gas producers.
- o *No additional investment incentives* – Outside of PSC terms, GoE could create other investment incentives that would enable gas APG gas flare reduction. However no such incentives are in place (e.g. favourable loans, investment participation of EGPC, tax incentives, etc.).

²⁴ It is important to note that these factors will apply to different uses of APG differently. Rich gas should not be sold directly to customers for example and any regulatory regime should be flexible enough for operators to identify the optimal economic usage of gas. The role of GoE should be to enable all these options to be possible.

- o *Uncertainty of cost recovery from PSC terms* – the PSC terms have no specific gas flaring reduction clause. Hence any investment in gas flare reduction is treated as any other upstream investment. The timing of cost recovery, the profit split and the valuation of gas are the same across all hydrocarbons. A more favourable approach to gas flare investments (e.g. EGPC investment participation, higher profit shares, or different cost recovery timings) could explicitly incentivise gas flare reduction.

Constraint 4: no formalised process for appraisal and approval of flaring reduction investments

Operators currently face uncertainty on the steps and administrative procedures that need to be taken to implement APG flaring reduction projects. With a clear framework in place that would be championed by the Government or EGPC, operators might have a clearer understanding on whether investments are worth it. Some aspects that are currently missing in Egypt are:

- o *Steps and approvals* required (tests, studies, licences) to ensure gas flaring investments are approved. This would help guide operators in their decision of gas flare reduction investments.
- o *Economic criteria* that would make a project feasible and ensure approval, which could include methodologies (e.g. discounted cash flow methods) and minimum eligibility criteria (e.g. NPV or IRR, including clustering possibilities)
- o *Technical criteria* and minimum standards needed to make a gas flaring reduction project viable (e.g. technologies eligible, equipment and materials to be used, safety standards to be met)

Constraint 5: lack of clarity on the institutional responsibility for the implementation of gas flaring reduction.

Whilst EGPC has been nominated to monitor gas flare levels and enforce them, this is not formalised in any form of legislation, creating uncertainty on the scope of EGPC’s regulatory responsibilities. The approval of gas flaring investments would require the coordination of several entities – this should be clarified for operators intending to make an investment. Additionally, EGPC’s dual role of commercial joint venture partner as well as regulatory agency creates conflict of interest and brings into question the full dedication to reducing gas flaring volumes.

Constraint 6: no formalised and GoE endorsed gas flaring policy

Despite the GoE commitment to reducing gas flaring, no clearly defined gas flaring policy exists. The policy can define the framework within which a regulatory framework can exist. Items to be included by a gas flaring policy are long term flaring targets, prioritisation over potentially conflicting policies (i.e. oil production maximisation) and institutional responsibilities. The policy would signal intent from GoE to reduce gas flaring level and could result in prioritisation of operators for gas flare reduction investments.

4 International lessons

To provide best practice recommendations on gas flaring reduction regulations in Egypt, we assess five international case studies. The detailed case studies are presented in the annex and this section summarises the main lessons learned applicable to the Egyptian context.

Selection of case studies

The case studies were chosen to provide a range of examples of best practice, of evolving regulatory frameworks and of countries which have yet to develop formal frameworks to reduce flaring:

- o **Alberta and Norway** are examples of international best practice, achieving and maintaining very low flaring rates over time. The countries have well-developed and stable regulatory frameworks. Alberta is of special interest for the use of annual tests of whether utilisation of associated gas is economic while Norway is of particular interest because of the use of taxes to incentivise flaring reduction and the combination of environmental regulation.
- o The **UK** is also a successful example and represents a different regulatory approach to Alberta and Norway. With a more laissez-fair approach, the regulatory regime is less prescriptive and relies on voluntary regulation and close cooperation between the regulatory entity and operators.
- o **Nigeria** provides an example of a jurisdiction with well-developed formal frameworks for reducing and eliminating flaring, but mixed records in practice. Nigeria is the second in the world in terms of volumes of gas flared. Despite some reduction on gas flaring levels over the past decade, it is far behind improvements made in other jurisdictions. Its problems in managing flaring arise, in particular, due to conflicting objectives and a lack of downstream markets.
- o **Kazakhstan** provides an example of an evolving framework. Kazakhstan only introduced formal limits on gas flaring in 2003. The initial regulations were not as effective as hoped. More recently, significant progress in reducing flaring has been made although concerns remain over monitoring and enforcement.

Overview of lessons

The lessons learned in this section are grouped and organised around the following building blocks of gas flare reduction regulatory frameworks:

- o **Regulation and policy**
- o **Institutional framework**
- o **Oversight and enforcement**

Figure 16 summarises the key lessons learned, as presented in more detail in the main part of this section.

Figure 11 Overview of international lessons learned

Regulation and Policy

- **Lesson 1:** regulations to encourage exploration of utilisation options
- **Lesson 2:** strong government commitment
- **Lesson 3:** targets must be realistic and aligned with other policies
- **Lesson 4:** access to viable downstream markets
- **Lesson 5:** transparency on obligations for operators
- **Lesson 6:** flaring taxes to be credible and integrated with other regulations

Institutional framework

- **Lesson 7:** regulatory responsibility should be separate from operational activities
- **Lesson 8:** stakeholder consultations lead to better outcomes
- **Lesson 9:** regulator needs to be well resourced and backed by supervisory rights
- **Lesson 10:** regulatory responsibility needs to be clearly defined

Oversight and enforcement

- **Lesson 11:** accurate measurement of flaring is critical
- **Lesson 12:** a transparent reporting process
- **Lesson 13:** targeted monitoring and inspections
- **Lesson 14:** penalties must be credible and have impact

4.1 Regulation and policy

Based on the reviewed case studies, the following lessons (via Figure 11) for regulatory content and policy design can be highlighted:

Lesson 1: regulations should encourage the exploration of options for associated gas utilisation

Regulations should be designed to incentivise operators to routinely look for viable opportunities to reduce gas flaring, if they are not already doing so. This can be in the form of mandated economic tests of flaring reduction investment options or, alternatively, the use of taxes on flaring designed to encourage utilisation of gas (see below). Such approaches are more likely to be effective than blanket prohibitions that take no account of the circumstances of individual sites.

Alberta has adopted a requirement for annual case-by-case assessments of the opportunities for utilising flared gas. All operators flaring above a threshold value are required to conduct net present value analyses (NPV) of possible gas utilisation projects every year. Operators must also investigate whether an extension of the project boundaries to include neighbouring fields, including those of other operators, can make utilisation projects viable

(clustering). The clustering requirements are particularly relevant for Egypt, where gas flare volumes are scattered across a large number of fields.

Economic tests of this type can be particularly valuable in helping focus the attention of senior management on the need to reduce flaring. They can also be used to help identify possible markets for otherwise surplus gas – particularly if there are requirements on operators to explore the options for combining with other operators and fields and if third parties are able to obtain information as a result of the testing process on volumes and costs of associated gas supplies.

Lesson 2: strong government commitment is required

The importance of strong political commitment to minimising gas flaring is clear from the case studies. Political commitment goes beyond simply setting targets for elimination. Governments must follow through on institutional and regulatory measures to ensure controls are set in place to limit gas flaring levels. Alberta and Norway, possibly the two most successful of the case studies, have long-standing commitments to minimising flaring which, in Norway's case, go back to the start of oil production. Nigeria stands in contrast, where government targets to eliminate flaring do not appear to have been followed-through.

Lesson 3: gas flaring targets must be realistic and aligned with other policy objectives

There is a need to strike an appropriate balance between cost and benefits when setting targets for reducing flaring. Overly ambitious targets, such as the rapid elimination of all flaring, face the risk of being ineffective and undermining the credibility of the original commitment to minimise flaring.

Among the case studies, the jurisdiction that appears to have been most successful in meeting targets is Alberta (Norway does not establish formal targets). In Alberta, no set target dates for the elimination of flaring has been established. The Province previously set its target in relative terms, as a 50% reduction on 1996 volumes, although has since moved to targeting absolute volumes.

Kazakhstan and Nigeria, by comparison, have at various times set a target of complete elimination of flaring within a short time period. Neither has achieved this and the credibility of their regulatory regimes has suffered – particularly in Nigeria. Also notable is that these targets have been set with what seems to have been little or no industry consultation and therefore seem to be solely politically driven. As a result, industry, at least in Nigeria, has opposed what it considers to be unreasonable and unachievable targets, consequently undermining the regulatory framework.

In many cases, the lack of follow-through on targets appears to result from the conflicting objectives of sustaining or increasing oil production and of minimising or eliminating gas flaring. This appears to have been a particular problem in Nigeria and may also have arisen in other cases such as Kazakhstan. There will always be cases where obligations to avoid routine flaring will run the risk of shutting-in marginal oil fields. However, this should not be exaggerated – appropriate regulatory frameworks will minimise this risk and encourage the use of associated gas in ways that can improve the economics of fields (e.g., reinjection).

Separating responsibilities for regulation of flaring from the entities responsible for promoting oil and gas production can help by making the potential conflicts more transparent, and offer alternative sources of advice to policymakers from outside of the industry (see the discussion below on institutional frameworks).

Lesson 4: access to viable downstream markets is important

Attempted elimination of continuous flaring without ensuring adequate downstream market access has achieved only limited success. The commercial incentives for operators to access wholesale markets play a significant role in them actively seeking economic investment options. Without a commercial pull factor for operators, fines simply become a tax or are not enforced.

A key feature of the most successful case studies is the ability for producers to access downstream gas markets, either domestically or for export. This creates the necessary economic conditions for investments to capture associated gas. Policymakers have a key role to play in supporting cost reflective gas prices, third party access to gas transportation and processing infrastructure, facilitating new infrastructure investments where necessary and allowing downstream gas market prices to be set at economically justified levels.

In Norway, a major contribution to reducing gas flaring in the country was the commissioning of the Norpipe pipeline in the late 1970s that provided access to the European gas markets. In Alberta, access to a liberalised and fair gas market equally allowed for operators to extract economic value from associated gas. In Nigeria, however, the absence of a viable downstream gas market, a result of electricity tariffs being set at prices below cost and poor payment records by electricity customers and enterprises, means the necessary investments in gas infrastructure to utilise APG are also not viable. This is despite an urgent need for Nigeria to increase its electricity generating capacity to alleviate crippling power shortages. Ongoing reforms to the electricity market and planned reforms to the midstream and downstream gas industry may help, but it seems unlikely these will be in place in time to meet currently proposed deadlines for eliminating flaring.

Lesson 5: transparency for operators to comply with regulations

Operators should be aided as clearly as possible in complying with gas flaring regulations. The regulations should therefore include instructions on the steps operators need to take to be compliant. This is particularly important at early phases of introducing the regulatory regime, as it enables operators to trust the regulatory system and be clear on what they need to do. It also reduces regulatory cost for monitoring and oversight for the regulator, as the reporting processes, formats and levels of detail required are in the public domain.

This level of transparency and clarity is particularly important in regimes where close cooperation between regulators and operators is required. These collaborative regulatory regimes have been shown to be far more successful than more prescriptive regimes (see next section).

Alberta, as the prime example of a transparent and collaborative approach, includes decision trees in its regulations, which are used to help operators in making decisions regarding flaring and/or venting reduction investments. The decision tree starts by asking operators to

assess whether flaring can be eliminated, then whether it can be reduced and lastly, allowing flaring subject to minimum technical requirements. In line with the concept of assessing the economic feasibility of utilisation options, the regulations define the precise methodology for conducting economic tests (including input parameters, assumptions and template spreadsheets). This ensures direct comparability across all utilisation projects and provides an objective assessment of commercial viability of the respective projects.

Lesson 6: flaring taxes need to be meaningful, credible and integrated with other regulations

As an alternative to continued requirements to assess the potential to economically utilise flared gas, taxes can be applied on all flaring (whether permitted or not). The requirement to pay a tax on flared gas creates a disincentive on flaring and encourages producers to seek ways to utilise this gas.

Among the case studies, Nigeria, Kazakhstan and Norway all impose taxes on flared gas. However, the effectiveness appears very different. While Norway claims significant success in reducing flaring as a result of the imposition of its CO₂ tax, the use of taxes appears to have been ineffectual in Nigeria and Kazakhstan. In both jurisdictions it appears more likely to be due to the very low level of the tax, meaning flaring remains much cheaper than investments in gas gathering and processing infrastructure.

In principle, it should be possible to eliminate all flaring if taxes are set high enough. However, this does of course run the risk of shutting-in oil producing fields to avoid the tax rather than leading to utilisation of flared gas. The economically efficient tax level would be the value of the economic damages caused by flaring. This is an extremely difficult value to estimate, but attempts can be made. Norway, for example, appears to have a relatively clear view on the costs of CO₂ emissions as is demonstrated by the offsetting of the expected costs of emissions certificates under its emissions trading scheme against the previous CO₂ tax level, to leave the total cost of emissions constant.

The use of a tax on flaring in Norway may be facilitated by it being part of a wider carbon tax. The use of an economy-wide tax will tend to increase the likelihood of the tax being applied in a consistent and non-discriminatory manner and mean that the setting of the tax level is more likely to be based on the costs imposed by emissions, than on special pleading on the part of the petroleum industry.

4.2 Institutional framework

The institutional framework of any regulatory system minimising gas flaring is most effective if the following principles (via Figure 11) are applied:

Lesson 7: regulatory responsibilities should be separate from operational activities

Potential conflicts between increasing oil production and reducing flaring need to be recognised in institutional arrangements. These conflicts are most acute in the case of self-

regulation where national oil companies regulate the industry's operations, as is currently the case in Egypt. But they also arise where regulation is theoretically separate but is, in practice, dominated by the interests of the national oil company.

Although Nigeria separates regulatory and operational responsibilities between an independent agency and a national oil company, conflicts persist between the goals of increasing oil production and reducing flaring. Many other factors contribute including the financial difficulties faced by the national oil company which mean it is often unable to contribute to the costs of investments to reduce flaring even it wished to do so. However, other case study countries seem to have successfully separated these responsibilities – helped by strong government commitments to reduce flaring.

Alberta, the UK and Norway all have separate and independent regulatory agencies, who act in line with their regulatory responsibilities of environmental protection and efficient use of natural resources. Consequently, they are not influenced by other policy objectives or commercial impacts from regulations. Ideally, the regulator should be an independent body, i.e. separated from any Government Ministry and self-financed (through fees or penalties from operators). However, it can also be embedded within a Ministry under the condition that its roles and objectives are clearly defined and focused on gas flaring reduction.

Lesson 8: stakeholder consultation leads to better outcomes

Involving stakeholders is important for developing realistic targets and feasible programmes for reducing flaring. The mechanisms used will differ between countries. Alberta is undoubtedly the most developed and formalised of the case study countries. A dedicated gas flaring and venting team of the government-funded stakeholder group, the Clean Air Strategic Alliance (CASA), meets on a regular basis to assess gas flaring objectives and changes to the regulation and policy. The team's members include representatives from industry, the regulator, governmental and nongovernmental environment organisations. The close involvement of stakeholders since 1996 is understood to be a key success factor for the steady drop in gas flaring volumes in Alberta, including in both setting targets and in preparing the implementing regulations.

Previous failures to consult on the realism of targets are one of the causes cited for the failures of past flaring bans in Nigeria and Kazakhstan. Industry in each country has found itself faced with requirements to eliminate flaring at short notice, when no supporting framework (such as the development of downstream markets) exists and where flaring has previously been accepted as a standard part of the production process.

Lesson 9: regulator needs to be well resourced and backed by supervisory rights

The success of gas flaring regulatory regimes hinges on the effectiveness of the regulator to enforce regulations. This means that any newly established regulatory regime needs to provide the regulatory authority with the necessary resources in terms of man power as well as budget. Besides staffing and funding, the regulator also needs to have legal backing and supervisory powers to pursue its objectives.

The Norwegian regulator (NPD) for example is backed up by strong supervisory rights if needed, such as rights to access the facilities, data or materials related to oil activities at any time, to take part in exploration activities, or to stay in the facilities as long as it is necessary. Strong supervisory powers increase deterrence and ensure compliance.

In the UK, over 50 staff at the Department for Energy and Climate Change (DECC)²⁵ had the main responsibility (in addition to DEFRA) for environmental management and inspections at offshore facilities (not including health and safety inspections). DECC Inspectors carry out routine and non-routine inspections to ensure compliance with relevant regulations and permit conditions, and to ensure that operations are carried out with due consideration to environmental aspects.

In Nigeria on the other hand, DPR, as the primary regulator, appears to lack the resources to adequately monitor flaring levels and compliance with permitted volumes. Inspections are rarely carried out. Instead, it relies largely on operators self-reporting.

Lesson 10: regulatory responsibilities need to be clearly defined

The regulatory responsibility for gas flaring needs to be defined clearly and any overlapping responsibilities should be avoided. Regulation of gas flaring typically falls on both upstream industry regulators and environmental regulators. Any gas flaring regulatory regime must take this potential fragmentation of regulatory responsibilities into account.

Different countries resolve the risk of overlaps in different ways. In some of the case studies, responsibility is split (e.g., requirements in Kazakhstan to obtain flaring permits from both the industry and environmental regulatory agencies). In others, both agencies have formal powers but the environmental agency opts to work through the industry regulator (as in Norway). Or the industry operator coordinates with the environmental regulator to ensure efforts are not duplicated in areas where a possible overlap could exist (as is the case in Alberta).

4.3 Oversight and enforcement

One of the key components of any effective regulatory regime is the ability of the responsible authorities to enforce the regulations and monitor compliance of operators. The key factors (via Figure 11) ensuring successful enforcement and monitoring are:

Lesson 11: accurate measurement of flaring is critical

Of critical importance for any regulatory framework is the adoption of accurate measurement procedures. This is to ensure that the volume and location of flares is known to regulatory authorities and all operators report on the same basis. Measurement of flared gas can either be specified in terms of metering requirements or by specifying a detailed

²⁵ The Ministry that has (among many other roles) some of the environmental responsibilities for the oil and gas sector.

methodology for calculating flaring and venting levels. Operators need to apply these methodologies rigorously and submit them to the regulator on a regular basis.

The most successful flaring and venting regulatory frameworks have very detailed and clear reporting requirements. In Alberta, all operators with flare and vent levels above 800 m³/month have to report their flare and vent volumes electronically. They can do so by either installing meters (given specific technical requirements) and/or by estimating the volumes (on the basis of a provided methodology). The reported flaring and venting volumes from each and every operator are made public.

In Kazakhstan, by contrast, there appears to be significant weaknesses in data collection and reporting. Reported flaring volumes were significantly lower than independently gathered NOAA satellite data. This makes it difficult to identify non-compliant operators and levy appropriate penalties.

Lesson 12: transparent reporting process

Clear reporting procedures also need to be put in place that support flare measurement requirements. Operators need to know how, when and what details need to be reported to the regulator. Ideally, this could be done through software tools that facilitates reporting and provide information in an organised and consistent manner. Having a rich, well organized and consistent dataset allows for tracking flaring volumes through time, assessing how facilities are performing, knowing where to focus efforts for reduction, and identifying possible anomalies in data to check flaring reports.

To alleviate regulatory burden and cost on the regulator, the reporting requirements should shift responsibility to operators, who are forced to establish management and control systems to ensure compliance with regulations and to improve their performance. This type of active compliance mechanism - complemented with adequate oversight - increases the operators' incentives to seek effective compliance, increasing oversight effectiveness. This has been adopted in Alberta, Norway and the UK.

Lesson 13: targeted inspections can make more efficient use of regulatory resources

One of the major challenges for enforcing gas flaring regulations is the regular conducting of inspections to investigate the veracity of operators' reporting. To make the most efficient use of scarce regulatory resources, a targeted approach to inspections can be adopted. Alberta is a good model to follow, where past track records of compliance are used to rank operators according to their likelihood of breaching regulations. Wells are classified by risk and operators by previous compliance records to identify those where monitoring is most required. This allows the regulator to focus efforts on those sites where the probability of non-compliance is highest and where non-compliant events have potentially the most negative impact.

Lesson 14: penalties must be credible and have impact

To act as a credible deterrent for non-compliance, penalties for unpermitted flaring need to be set at a high enough level to incentivise operators to comply with the regulations. However a balance has to be found between penalties that are high enough and credibly enforceable. In many countries that rely on oil production as a key economic growth sector, the ultimate punishment of withdrawing extraction licenses of operators is not likely to be credible due to the adverse effects on the economy as a whole.

Penalties can take a variety of different forms and can range from a fine for excess flaring volumes to the forceful implementation of gas flaring reduction plans (Alberta). In Alberta, different punishments apply according to the seriousness of noncompliance and whether the operator has previously breached the rules or not.

Any penalties should take account of the extent to which alternatives to flaring exist. Where there are no alternatives (e.g., due to the absence of downstream markets), penalties will be either ignored, not applied or become an additional business cost and potentially result in the unnecessary shut-in of oil production. This appears to be partly the experience in case study countries including Kazakhstan and Nigeria where what are supposedly stringent penalties for flaring without permission appear to be either ignored or only applied intermittently. This also re-emphasises the importance of setting realistic targets for reducing flaring – if operators are to be penalized for not achieving targets then the targets themselves must be realistically capable of achievement.

5 Reform options evaluation

In this section of the report we present and evaluate reform options for gas flaring and venting in Egypt. We group the options by reform building block and evaluate them against criteria agreed on with stakeholders from EGPC, Ministry of Petroleum and Natural Resources, EGAS and GANOPE during the team's visit in Cairo in September 2016. The resulting preferred reform option will then be used to recommend regulatory options and an implementation plan in Section 6.

5.1 Approach

5.1.1 Building blocks of the regulatory framework

Regulating gas flaring requires changes, reforms, and adjustments across a number of dimensions. We identify the main areas observed in other jurisdictions and group them together into three building blocks. The building blocks are:

- o **Regulation and policy** - this covers the 'push factors' of a regulatory regime, which force operators in making or at least considering gas flare reduction investments. These reforms therefore define any regulatory framework and the guiding principles for gas flare reduction. Typically, this will be determined and supported by secondary legislation, guidelines, and policy declarations.
- o **Institutions** - the clear definition of responsibilities across institutions is important for successful implementation of regulations. We therefore treat this as a separate building block of regulatory reform.
- o **Oversight and enforcement** - all aspects related to 'bringing the regulatory framework to life'. This includes monitoring, evaluation, and verification procedures. Also included are reporting requirements and data management. While many formal aspects will overlap with regulatory framework, this building block is focused on procedure, processes and institutional interactions.

The building blocks and their respective reform areas are presented in Figure 12.

Besides these building blocks that define the regulatory approach to gas flaring and venting, **wider market reforms** need to be addressed to add complementary incentives for gas flare reduction investments. These can be considered as 'pull factors' for making investments more attractive for operators, i.e. external factors that will improve the economics of investments. Changes under this category go beyond gas flaring and will have wider impacts across the Egyptian gas market in general. We will therefore not present them in great detail in this Report; however we highlight some of the key aspects that should be considered.

Figure 12 Building blocks and reform areas

| Regulation and Policy | Institutions | Oversight and enforcement |
|--|--|--|
| <ul style="list-style-type: none"> • Targets • Permits • Operator obligation • Economic test • Gas flaring investment approval process • Minimum technical standards | <ul style="list-style-type: none"> • Independence • Regulatory scope • Stakeholders • Int'l commitment | <ul style="list-style-type: none"> • Metering/measuring • Reporting • Verification/Monitoring • Enforcement • Education |

5.1.2 Overview of reform options

For each of the reform areas presented above, we identify two to three different reform options. The options presented are drawn from international lessons and vary in their regulatory approach. In general, we identify the range of options covering the most laissez faire regulatory approach to the most prescriptive approach. All options that are presented and discussed in the remainder of this section are summarised in Table 1.

Table 1 Overview of reform options

| Regulation & Policy reform options | | | |
|------------------------------------|--|---|--|
| Targets | No flaring target | Industry target | Site-specific targets |
| Flaring permits | Voluntary | Permits for exceptional flaring | |
| Operator obligation | Voluntary | Propose plans for economic utilisation | Deadline set to eliminate flaring |
| Economic test | No consideration of economic tests | Set out economic test guidelines | |
| Investment approval process | Transparent steps to follow to ensure approval | | |
| Minimum technical standards | Technical standards operators need to abide by for allowed flaring | | |
| Institutions reform options | | | |
| Regulatory scope | Monitoring only | Monitoring, evaluation and verification | Monitoring, evaluation, verification and |

| | | | |
|---|--|--|--|
| | | | enforcement |
| Independence | Set up separate regulatory unit within EGPC | Ministry subdivision | Independent regulator |
| Stakeholders | Stakeholders consulted ad hoc | Regular meetings with stakeholder group(s) | Formalised stakeholder interaction process |
| Oversight and enforcement reform options | | | |
| Metering/measuring | Precise methodology for estimating flares | Technical standards and requirements for meters | |
| Reporting | Self-reporting within set out reporting requirements | Data collection by on-site regulators | |
| Verification | High level, desk-based verification of reported data | Inspections conducted on the basis of different criteria | |
| Enforcement | Penalties based on volume | Penalties based on severity of non-compliance | |

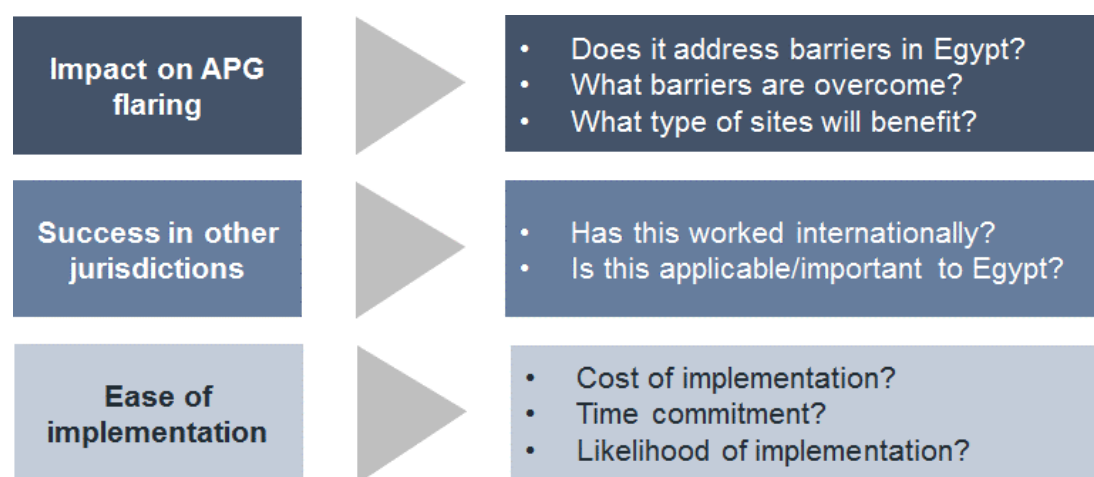
5.1.3 Criteria for assessment

In order to make recommendations on suitable regulatory changes for Egypt, we assess each option within one reform areas against a set of criteria. The criteria have been determined in consultation with stakeholders during the team’s visit in Cairo in September 2016 and cover the following areas:

- o ***Estimated impact on APG flaring in Egypt*** – Different reform options vary in their impact depending on market specifics and the nature of flaring. Flaring in Egypt is characterised by relatively small volumes scattered over a large number of upstream production sites. Additionally, operators face regulatory constraints as identified in previous sections. Under this criteria we assess whether the proposed options target Egypt-specific conditions for APG reduction.
- o ***Success in other jurisdictions*** – as most options presented in Table 1 have been drawn from international lessons, we assess under this criteria how successful reform options have been internationally. This is based on the case studies presented in the Annex A1.
- o ***Ease of implementation*** – Each reform option requires a different level of financial commitment as well as human resource effort and policy support. This criteria will therefore assess the ease of implementation for each option as well as the speed with which we would expect the reform to be finalised.

Figure 13 summarises the criteria and the main questions we address for every reform option.

Figure 13 Criteria for assessment and key questions



5.2 Regulatory reform options

5.2.1 Reform options: regulations and policy

For regulation and policy we identify reform options in the following categories:

- *Gas flaring targets* – at what level, if at all should flaring targets be set
- *Flaring permits* – to inform operators on the volumes of APG they are allowed to flare, permits can be introduced.
- *Operator obligation* – depending on the regulatory regime the Government of Egypt wants to introduce, operator obligations can be lax or very stringent.
- *Investment approval process* – a transparent process clarifying what is needed by when from operators to implement gas utilisation projects.
- *Economic test* – a targeted and flexible regulatory approach should focus on the economic feasibility of APG flaring reduction investments and a variety of economic tests can apply.
- *Minimum technical standards* – for those flares that are permissible, minimum technical standards should be set to minimise health and safety risks.

Targets

Targets in some form or another are used across most jurisdictions as part of an overall policy commitment to motivate reductions in gas flaring. There are three main approaches to consider:

- **No flaring target** – No explicit targets are set. Voluntary industry actions and/or other regulatory measures are expected to sufficiently reduce flaring, with no

additional measures set out if flaring reductions are inadequate. It may not be feasible to set explicit targets if monitoring capacity is lacking or if there are coinciding efforts to expand oil and gas production (as has been the case in Nigeria). Setting flaring targets can also be difficult for an industry *in decline*, as is the case in the UK, as this will limit the interest in investing in gas-capturing infrastructure. Norway does not have a broad target for gas flaring, but flaring is ultimately still limited by other strong regulatory measures. This approach can work if other regulatory measures are strong enough to deter flaring (economic testing requirements, emissions taxes, penalties for missing site-specific targets, etc.). Otherwise a broad target should be put in place to signify a top-down commitment to reduce flaring.

- o **Industry-wide flaring target** – Flaring targets are set at a national level, usually as part of an overall policy commitment to reduce flaring. By also prescribing further measures that activate if the target is exceeded, it can broadly incentivise producers to reduce flaring in order to avoid punitive enforcements or more stringent regulations. A broad target is likely easier to monitor, but it may also create ‘moral hazard’ incentives, allowing some producers to continue flaring without consequence while other producers bear the burden of flaring reduction investments. Alberta uses a macro-target approach, but imposes limits on individual sites if the province-wide limit is exceeded. Alberta also sets standards for gas flaring that individual sites cannot exceed, but not on a site-by-site basis. Alberta’s example provides a ‘light touch’ approach, leaving operators to figure out how to limit flaring on their own. Kazakhstan serves as a negative example, as a law was introduced that made flaring illegal overnight, which was unrealistic given it required operators to cease flaring that was essential for ongoing production. Nigeria has also regularly set ‘flare-out’ deadlines, yet has had little success due to limited regulatory and industry backing.
- o **Site-specific targets** – Setting targets for each production site can avoid the moral hazard issues of industry-wide targets and can also allow for nuance in understanding what level of reduction is feasible for sites of differing geographic and environmental conditions. However, such prescriptive targeting would require a high level of regulatory capacity, detailed on-site visits, and would potentially excessively burden producers with targets that would not pass economic tests. This approach would be particularly difficult given the geographic dispersion of Egypt’s flaring sites (Figure 8). Alberta does not prescribe site-specific targets, but it does set out criteria for which particularly poor-performing individual sites must shut down. The UK regulator uniquely allows its northern team in Aberdeen and its southern team in London to regulate sites as they see fit, with the former doing so on a site-by-site basis, and the latter setting broad targets. Norway sets targets as per the original APG utilisation proposals of new sites and notably has significant regulatory capacity to follow up on these targets.

The existing framework in Egypt in effect sets a flaring target of 1 mmscfd for each site. However its enforcement and application seems to be lacking rigour. Such a target seems to be firstly difficult to enforce (because requiring constant and detailed monitoring), secondly being too ‘heavy handed’, and thirdly being arbitrary. We recommend a system that is sufficiently flexible to allow site-specific factors to be considered when setting individual site targets. Ideally, the regulatory framework should leave it up to operators (in support

with EGPC and/or national or international technical experts) to identify the most economically feasible utilisation option. If none of the options are economically or technically feasible, operators should not be faced with an arbitrary target.

The setting of an industry-wide target can also coincide with international involvement, notably the World Bank’s ‘Zero Routine Flaring by 2030’ initiative as part of the Global Gas Flaring Reduction Partnership (GGFR). This is not a *necessary* step as the UK is noticeable absent from the GGFR and has been relatively successful in reducing gas flaring; though it should also be noted that UK-based BP and UK-incorporated Royal Dutch Shell are committed international oil companies. However, Alberta and Norway, along with 16 other countries, 13 IOCs, and 3 developmental bodies are members. The World Bank offers financial and technical assistance for gas flaring projects through this body and the GGFR website advertises some past successes.²⁶ While joining the GGFR by itself would not reduce flaring, one of the main benefits to joining the GGFR may simply be opening Egypt to international collaboration and knowhow on gas flaring issues. This may include endorsing GGFR’s ‘Global Standard’ for gas flaring reduction,²⁷ which has been devised as a widely applicable framework for collaboration, expanding projects, and reducing barriers to APG utilisation. Joining the GGFR would help signify intent on the part of the GoE and enable Egypt to continuously learn from best practices around the world.

Targets can also be aligned with Egypt’s Intended Nationally Determined Contributions (INDCs). As part of the international climate agreement that occurred in Paris in December 2015 - the UN Framework Convention on Climate Change (UNFCCC) – countries are to publically outline their post-2020 climate actions (INDCs). INDCs are aimed at being climate contributions that are aligned with national priorities, circumstances, and capabilities. Egypt has already submitted its INDCs in November 2015, which included “venting and flaring” as one of the GHG emission reduction actions under oil and natural gas. This public commitment can give additional impetus to efforts of gas flaring reduction and the setting up of the regulatory framework for flaring and venting. The inclusion of gas flaring and venting into Egypt’s INDCs will contribute in CO2 reduction and could provide additional access to international funding mechanisms.

Table 2 Option evaluation table – Targets

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|----------------|-----------------|-----------------------|-----------------------|--------------------------------|------------------------|
| Targets | <i>Option 1</i> | No flaring target | ✘ | ✓ | ✓✓✓ |
| | <i>Option 2</i> | Industry target | ✓✓ | ✓✓✓ | ✓✓ |
| | <i>Option 3</i> | Site-specific targets | ✓✓✓ | ✓✓ | ✓ |

²⁶ Highlights include: a Partial Risk Guarantee for a project in Nigeria where Chevron Nigeria Ltd provides gas to the Egbin power plant; a project in Kazakhstan that included GGFR members Chevron and ExxonMobil which reduced gas flaring at the Tengiz oil field by 94%.

²⁷ All details on GGFR and supporting documentation can be found under the following link www.worldbank.org/en/programs/gasflaringreduction#1

Box 1 Recommendation: Targets

We recommend the approach adopted in Alberta for Egypt, where an industry-wide, medium-term target is set that provides the policy framework for regulating flare levels and gives purpose for reducing flaring volumes. The target should be established collaboratively with industry representatives and should be a level of flaring the industry, the regulator and policymakers strive to. If the target is not met, the new target needs to be revised and the main reasons for not reaching the target should inform the new target level. How the target is reached should however be defined by site specific economic and technical evaluations done by operators. This means that a flaring target is different to the allowed gas flaring levels at each site.

We recommend that a gas flaring target (or gas utilisation, or gas to oil ratio target) is set for the short to medium term, say, 2020. The target should be kept under review by the regulatory authority in consultation with stakeholders. Because industry-wide, the target is non-binding and acts as a statement of intent and purpose to reduce gas flaring levels. It could be set in conjunction with international climate commitments. If not met, it should trigger a review of parameters, e.g. economic test parameters, minimum threshold levels, etc.

Flaring permits should be issued for one year at a time and should detail the allowed level and type of flaring. There are in effect two reasons why an operator might be permitted to flare or vent gas:

- o For the flaring of associated gas for a limited period where it is not economically viable or technically feasible to utilise this gas.
- o For temporary flaring and venting required for operational reasons.

We propose that permits should be issued annually establishing permitted flared and vented volumes for the above two reasons. These permits are in addition to any other permissions that may be required (e.g., from the Minister of Environment).

Egypt should also join the Global Gas Flaring Reduction Partnership (GGFR) and embrace its 'Zero Routine Flaring' initiative as a general signal of intent from the GoE and to benefit from international financial and technical assistance.

Flaring permits

Flaring permits provide clarity to operators regarding the levels of flaring allowed and the circumstances under which they can flare. Permits are used in those jurisdictions where site specific obligations apply. Whatever permitting regime is put in place would be dependent on what targets are decided on: on a site-by-site basis or broader permits as part of an industry-wide flaring target. There are mainly two different approaches to allowing flaring on a permitted basis:

- o **Voluntary** – Flaring is not explicitly prohibited at any threshold or type and instead industry is relied on to voluntarily reduce flaring. While producers are incentivised to reduce flaring to the extent that it economically recovers gas, lowers costs, improves safety, etc., this is unlikely to lead to any significant

reductions in flaring. In effect these types of permits would not set any obligations or limitations on flare volumes to the operator, but would only outline the circumstances under which flaring is allowed. A common theme from our successful case studies is flaring being limited through permits on either a site-by-site level or by only permitting flaring on a non-routine basis, which partly depends on the policy regarding overall flaring targets.

- o **Permits for exceptional flaring** - This approach makes routine flaring illegal, but allows for permits for ‘exceptional’ flaring. This could be based on flaring thresholds (related to an overall flaring target), safety concerns, or economic and technical feasibility of gas flare reduction. The UK issues time-limited permits and the allowed timeframe is dependent on the size of the site. Norway similarly sets emission limits on a case-by-case basis. However, this approach requires a significant amount of regulatory capacity to engage in site-by-site monitoring of flaring volumes. Furthermore, any regulatory setup should prioritise ending routine flaring, which tends to be the most significant form of gas flaring.

Permits are not an essential part of mature regulatory frameworks, where operators know the processes well and are fully informed on what is permissible and what is not. Alberta does not issue permits for flaring, focusing on industry-wide targets, but it considers venting unacceptable and lays out special directives if an operator deems venting absolutely necessary. However for newly established regulations, permits can help in making the obligations and allowed flaring volumes/types transparent.

Table 3 Option evaluation table - Flaring permits

| | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|-----------------|--|-----------------------|--------------------------------|------------------------|
| Flaring permits | Option 1 Voluntary | x | x | ✓✓✓ |
| | Option 2 Permits for exceptional flaring | ✓✓ | ✓✓✓ | ✓✓ |

Box 2 Recommendation: Flaring permits

Given permits can help the obligation of new gas flaring regulations more transparent, we recommend having a form of permitting system in place for Egypt. The general principle should be that continuous flaring and venting is prohibited, although temporary exemptions for flaring are possible for existing fields on the grounds of economic or technical infeasibility of eliminating flaring and exemptions may also be permitted for smaller fields. Flaring and venting for safety reasons is always permitted, although being subject to ex-post assessment of the justification, as is temporary flaring and venting for operational reasons. However, for the latter, a permit must be obtained in advance where the volumes of gas flared can be expected to be significant.

As we recommend a tailored approach where site-specific conditions should be taken into consideration, a permitting system for exceptional flaring circumstance would be sensible. The circumstances under which continuous flaring is allowed could include the following

for example:

- o Safety reasons
- o If continuous flaring is below a threshold level
- o If not economically feasible to utilise gas
- o If not technically feasible to utilise gas

We recommend that the smallest fields (measured by flared volumes) are effectively exempted from the prohibition on routine flaring. This is to avoid disproportionate regulatory and company effort being directed to fields that have little impact on total flared volumes. These fields would still be required to report flared and vented volumes. It would be the responsibility of the operator to ensure that volumes do not exceed the threshold above which prohibition applies.

The threshold should be established periodically by the regulatory agency, in consultation with stakeholders. The thresholds applied in Alberta, 0.03 mmscfd, or the United Kingdom, 2.6 mmscfd, could be cited as examples.

Operator obligation

The extent to which operators are obligated to reduce gas flaring and/or figure out utilisation options can vary in intensity:

- o **Voluntary** – Producers engage in flare-reducing investments on a voluntary basis. This approach has worked in Alberta, where operators are given a high flexibility in achieving reductions, but other mechanisms are in place to ensure overall targets are met. However, operators cannot be relied on if they have not ‘bought in’ to reducing flaring or suitable other regulatory requirements are in place. Nigeria set out to eliminate flaring, but having not been properly consulted nor provided with a guide for economic utilisation, operators deemed the set goals unrealistic and flare reducing efforts were uneven and ineffective. A voluntary approach cannot be relied if operators do not agree with flare-out goals and/or if operators do not have the technical capacity to develop flare utilisation infrastructure on their own.
- o **Propose plans for economic utilisation** – Require operators to submit a plan to utilise APG, particularly for proposed sites. Proposed plans can be deemed to prefer certain utilisation options (bringing APG to the market is prioritised in Kazakhstan), but a flexible approach is more likely to minimise APG. If operators are required to submit an utilisation plan, the most effective regimes (Norway and the UK) treat utilisation plans as a ‘discussion’ rather than a prescriptive approach. Sites will vary widely in which utilisation is most appropriate and prescriptive guidelines are likely to overlook this. Utilisation plans should also be considered at the very start of operations rather than an afterthought. Nigeria has set it so operators must submit a development plan

two years *after* oil production begins, when APG-reducing investments are more likely to disrupt production and be more difficult to implement in retrospect.

- o **Deadline set to eliminate flaring** – Set a strict deadline after which operators are not allowed to flare. This option will certainly not work if the set deadline is extremely unrealistic, such as Kazakhstan’s initial law that made flaring illegal overnight. Nigeria has set successive ‘flare-out’ deadlines, beginning in 1984, with 2008 and 2010 being the most recent deadlines. Such deadlines are particularly unrealistic if they coincide with a period in which oil production is expanding. Such strict deadlines are unlikely to work in practice given production practices will vary from site-to-site, making operators unlikely to go along with them.

Table 4 Option evaluation table - Operator obligation

| | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|----------------------------|--|-----------------------|--------------------------------|------------------------|
| Operator obligation | <i>Option 1</i> Voluntary | ✓ | ✓✓ | ✓✓✓ |
| | <i>Option 2</i> Propose plans for economic utilisation | ✓✓✓ | ✓✓✓ | ✓✓ |
| | <i>Option 3</i> Deadline set to eliminate flaring | ✓ | ✗ | ✓ |

Box 3 Recommendation: Operator obligation

We recommend stringent requirements for operators to propose a plan of economic development at crucial stages of production, in particular at the start of production. This gas utilisation plan should be adhered to and the regulator should supervise its implementation. This would largely match the existing requirements operators currently have in Egypt, i.e. to submit a gas utilisation plan as part of Field Development Plans. Implementation costs would therefore be low and with stringent oversight, the impact on APG flare levels could be significant. Additionally to the initial development, economic tests and assessments for gas utilisation could be in place. This is the focus of the ‘Economic test’ subsection below.

Economic test

As noted above we recommend a tailored and site-specific approach that is focused on the economic feasibility of gas utilisation options. Besides the initial gas utilisation plan that should be developed by operators, further economic tests could be made to assess whether these planned investments are economically feasible. Requirements for these economic test can be set out into two categories:

- o **No consideration of economic tests** – Producers would not be required to submit economic tests on how they plan to eliminate flaring. This approach can work when operators have ‘bought in’ to reducing flaring and have the technical

capacity to develop and/or experiment with flare-reducing investments. The UK lets operators reduce flaring as they see fit and, given its success in reducing flaring, there does not appear to be the need to set out specific economic test guidelines. This is not the case in Nigeria, where a lack of ‘buy in’ by operators coincided with no mechanism being set out for testing the economic viability of flare reduction. Operators were thus given no indication of how reducing flaring could be technically feasible amid concurring encouragement to increase oil production.

- o **Set out economic test guidelines** – This entails a prescriptive approach, in which the government and/or regulator sets out guidelines for what kind of economic test should be conducted. This may also involve motivating operators to utilise APG in a preferred way, such as reinjection to boost oil production or bringing APG to the market. Alberta has an explicit economic test methodology that guides operators to make this assessment on a frequent basis. If the results of the test lie above an industry-wide NPV threshold value (which is set in Alberta at 50,000 CAD\$), the investment needs to be made. If not, flaring is allowed under specific conditions. The specific value of the benchmark above which investments are required are a function of the willingness of GoE to reduce gas flaring (low threshold for high willingness) and the commercial impact on operators (high threshold if willing to accept a greater commercial burden for operators). The precise value of the threshold should be established between the regulator and operators.

Table 5 Option evaluation table - Economic test

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|----------------------|-----------------|-------------------------------------|-----------------------|--------------------------------|------------------------|
| Economic test | <i>Option 1</i> | No consideration for economic tests | ✓ | ✓✓ | ✓✓✓ |
| | <i>Option 2</i> | Set out economic test guidelines | ✓✓ | ✓✓✓ | ✓✓ |

Box 4 Recommendation: Economic test

We recommend that, as a complement to the gas utilisation plan that needs to be developed during the initial stage of field operation, operators are obligated to conduct frequent economic tests for utilisation options. This would ensure that operators continuously reassess their utilisation options with changing external parameters and bring gas flaring to the front of operators’ agendas regularly. Additionally, the mechanism would not be unduly burdensome for operators, as the methodologies and calculation formats/spreadsheet would always be the same and, depending on where the threshold for the economic test is set, would see operators benefit from such investments.

It should also take into account the possibility of aggregating several small fields in proximity to each other where this can lead to economic levels of associated gas recovery (clustering). It would be unduly burdensome to apply an economic test to all flaring fields on an annual basis. Therefore, we recommend that the test is applied:

- o To larger fields (measured by flared volumes), annually. Permits for these fields would be issued for one year if gas utilisation projects are found to be uneconomic.
- o To smaller fields, every three years. Permits for these fields would be issued for one year if gas utilisation projects are uneconomic but eligible to be renewed annually until the next economic test is applied.

In Alberta, for example, sites must conduct an update on its gas utilisation economics should the combined volume of flaring or venting reach more than 800 m³/day. The precise threshold would depend on the technical parameters of fields in Egypt and should be set in coordination with industry representatives.

While annual tests may appear to impose a high workload, after the initial test has been prepared it should be possible, in most cases, to simply update this with the most recent gas price information (from an accepted price forecast source) and any new evidence on costs of utilisation options. It would be beneficial to test the effectiveness of these economic tests initially by adopting a 'pilot phase', where only larger operators which are likely to have better technical ability should conduct economic tests. During this pilot period, the economic test and its requirements can be calibrated and adjusted by taking into account the difficulties encountered by these large operators. Once finalised, the economic test can be rolled out across all operators.

Developing an initial template with clear submission requirements helps make the process easier for operators. The details and parameters to be used in the economic test should be clearly defined in the regulations or associated directives.

Furthermore, efforts should be made to streamline the approval of projects should they be deemed economically advantageous (see next section).

Gas flaring investment approval process

A requirement for economic testing would be directly linked to the approval process for any proposed gas flaring investments. It is very important for such a process to be transparent and efficient in order to streamline the implementation of projects deemed to be beneficial. Egypt currently has no formalised process for the appraisal and approval of flaring reduction investments, which has created uncertainty among operators who are currently dealing with an informal, ad hoc process.

Alberta's decision tree approach to flaring regulations assists in this matter as it clearly defines the process for which operators should evaluate gas utilisation options, easing their decision-making, and this also establishes a starting-off point for regulators looking to evaluate whether an operator has taken the necessary steps for its economic evaluations.

Another consideration would be to have a 'fast-track' option for investments that have certain favourable characteristics for example a low CAPEX outlay, an IRR or benefit-cost ratio that is higher than a set threshold, etc.

By setting clear and agreed upon guidelines for what constitutes an economically advantageous gas utilisation project, this should ultimately sidestep the need for EGPC to

approve investments. If both EGPC and operators agree on the guidelines set out for economic testing, approving these projects essentially becomes a formality rather than a process in itself. In Alberta, operators must detail how they come to their conclusions on economic viability but if a project is economically viable, there is no additional process for then approving the operator undertaking the project.

Box 5 Recommendation: investment approval process

We recommend the adoption of a decision tree for investment approval to create full transparency on the process from concept to operation of the gas flare reduction equipment. The key features of the decision tree should be:

- o Each step required for investment approval together with the documentation required and responsible government agency.
- o The timing within which the responsible government agency needs to respond to requests.
- o Threshold values that determine whether the investment is deemed ‘fast track’.
- o Exempted steps if the proposed investment is classified as ‘fast track’.
- o Contact details for the responsible agency to submit investment decisions.

In Egypt, most of this process is currently approved by EGPC. We do not recommend that this should necessarily change. However we would recommend formalising this process and the required documentation to create transparency and thereby incentivising operators to take investment decisions.

Minimum technical standards

It is unrealistic for gas flaring to be eliminated fully. Hence there will remain small continuous or temporary gas flaring activities. To minimise the health, environmental, and safety risks of these operations, minimum technical standards should be set. The standards could include a variety of provisions such as (i) flare conversion efficiency, (ii) smoke emissions, (iii) ignitions, and (iv) flare stack design.

While a potentially important regulatory feature, minimum technical standards are not a necessity when setting up a regulatory framework. The key features of regulations listed above can be implemented without minimum gas flaring standards enshrined in regulation. For adequate environmental, health, and safety standards however they should be considered and are part of any successful regulatory framework.

Box 6 Recommendation: Minimum technical standards

Where flaring does take place, it should conform to minimum technical standards. Currently, the only limitation appears to be the maximum opacity standard imposed under environmental regulations. This is not considered to provide sufficient protection

to the local environment around the flare stack. Technical standards that are appropriate to Egypt will need to be developed. However, these can be based on international best practice. For example, Alberta applies the following minimum requirements for the location of flare stacks:

- o 50m away from wells;
- o 50m away from storage tanks containing flammable liquids;
- o 25m away from any oil and gas processing equipment
- o 100m away from surface improvements; and
- o 100m away from occupied residences.

We propose that these minimum standards should apply to both existing and new flares. This may require relocation of some existing flare stacks and, therefore, increased costs. However, we consider it would be difficult to justify applying different standards of protection for existing and new flares. The costs of compliance should, in any case, be a recoverable cost under the relevant PSC.

5.2.2 Reform options: institutions

An essential part of the regulatory framework is the institutional set up supporting gas flaring reduction efforts. This section focuses on the following reform areas:

- o *Regulatory scope* – the roles and responsibilities of the regulatory authority
- o *Independence* – the different levels of independence needed for the regulator
- o *Stakeholders* – the levels of interaction and involvement of stakeholders and in particular operators

Regulatory scope

Besides the independence of the regulator and its organisational position, it is important to clearly define the scope of the regulator. Under current arrangements EGPC appears to be monitoring the data supplied to them by operators. Any further actions, and in particular enforcement of the minimum flare levels, are apparently overridden by the general government policy of prioritising oil production. We assess and propose two reform options varying in the degree of regulatory oversight and enforcement, the regulator will be able to take:

- o **Monitoring, evaluation, and verification** – Leaving the regulator’s scope to monitoring, evaluation, and verification would be a small step up from EGPC’s current activities. EGPC currently collects daily data on gas flaring from all of its sites, but a consistent framework for evaluation and verification does not appear to be in place. EGPC’s data collection efforts are a very good foundation for a successful regulatory framework, but such numbers need to be regularly

evaluated and verified in a transparent manner for: accuracy against other measures (such as NOAA estimates), statistical anomalies, and to give a clear overall picture of gas flaring progress in Egypt. Given it may be unrealistic for an independent regulator or ministry subdivision to regularly monitor sites – Nigeria, for example, needs to rely on self-reporting due to limited capacity to carry out inspections at dispersed sites despite a mandate to do so – Egypt may need to rely on operators’ self-reporting for the near future. Hence the need for the regulator to develop an effective evaluation and verification system to go along with its regular monitoring. As regulatory capacity increases, a web-based tool for monitoring and regular on-site visits for evaluation and verification may be more feasible, as is the case in Norway. This option would not give the regulator enforcement powers, as it would rely on self-regulation.

- o **Monitoring, evaluation, verification, and enforcement** - Should the deemed regulatory agency be given enforcement powers in cases of non-compliance with gas flaring initiatives, it is imperative that their enforcement ability is considered credible. The AER in Alberta gives industry the flexibility to reduce gas flaring as it sees fit, but the AER is able to impose strong penalties (fines, site suspensions, etc.) if non-compliance occurs through a transparent enforcement mechanism. Norway and the UK also have credible and transparent enforcement mechanisms, such as EU ETS, while allowing for discussions on a case-by-case basis. Nigeria and Kazakhstan both provide examples where enforcement mechanisms failed due to a lack of credibility. Nigeria set out penalties for failing to comply with its zero-flaring target, but had little capacity to actually follow through any such enforcement. Responsibility was also confused by overlapping mandates between the energy and environment ministries. Kazakhstan briefly introduced its own emissions trading scheme in 2013, which would have directly penalised flaring. However, the scheme has been temporarily suspended due to industry backlash.

It is important that regulators have credible enforcement powers. This provides an incentive to operators to be compliant with the regulations. The regulatory scope of the regulatory agency should therefore encompass enforcement and all legal instruments should be in place to support the regulatory agency fully in implementing the enforcement tools. We would therefore recommend giving the full regulatory scope related to gas flaring to a single entity (which, in future, should be an independent regulatory agency). This includes monitoring, evaluation and verification of data published by the operators as well as enforcement.

Table 6 Option evaluation table – Regulatory scope

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|------------------|----------|---|-----------------------|--------------------------------|------------------------|
| Regulatory scope | Option 1 | Monitoring, evaluation, and verification | ✓ | ✓ | ✓✓✓ |
| | Option 2 | Monitoring, evaluation, verification, and enforcement | ✓✓ | ✓✓ | ✓✓ |

Box 7 Recommendation: Regulatory scope

The main functions of the regulatory agency implementing the recommended policies would include:

- o Establishing economic and other viability tests and assessing submissions by operators.
- o Issuing temporary and time-limited permits for flaring and venting.
- o Monitoring and enforcing compliance with permitted flaring and venting levels.
- o Setting and updating technical standards for flaring and venting.
- o Advising on the achievement of flaring reduction targets.

When performing these functions, it is important to recognise that the Regulatory Authority will need to balance multiple objectives. In particular, it needs to be able to take steps to reduce flaring and venting while minimising impacts on the achievement of the government's targets to increase oil production.

Independence

We discuss three levels of regulatory independence for operators:

- o **Set up separate regulatory unit within EGPC** – Presently, most upstream regulatory functions are within EGPC itself, with no distinction between regulatory functions and commercial functions. This is an inherent conflict of interest as the efforts of the former to limit gas flaring may be superseded by the efforts of the latter to increase oil and gas production. Acknowledging this issue, a first step may be to explicitly separate these functions within EGPC, creating an in-house regulatory team at EGPC. As in the case of setting up a ministry subdivision (see below), the established in-house regulatory team could serve as a step toward later creating a fully independent upstream regulator. There is already a precedent for this in Egypt, with the Gas Regulatory Affairs team that now operators within EGAS and is set to eventually become an independent regulator.
- o **Regulation by ministry subdivision** – This approach gives regulatory authority to a ministry or ministry subdivision. In other cases, such as Nigeria and Kazakhstan currently, or the UK until recently, authority on gas flaring falls under both energy and environment ministries. From the Egyptian perspective, this approach could disentangle the regulatory side of gas flaring from EGPC's key role in the operational side. Putting gas flaring under the purview of a ministry subdivision(s) could act as a step toward establishing an independent regulator, as has been the case in the UK, which has recently shifted responsibility for flaring from its environmental ministry to an independent regulator, the Oil and Gas Authority.

- o **Independent regulator** – Establishing an independent regulator, with sufficient capacity and authority, tends to be the ‘gold standard’ for managing and enforcing regulatory issues in energy. This encourages regulatory specialisation, ‘proactive’ and innovative regulation, and minimises political interference. An independent regulator is a key facet of two of our successful case studies, Alberta and Norway, and the UK has recently followed suit. In short, Egypt should strive to establish an independent regulator of upstream oil and gas issues. However, this requires both time and regulatory capacity. Setting up an inept and ineffective regulator would be counterproductive, discouraging operator cooperation. This approach should be considered a long-term goal that can coincide with first shifting regulatory authority to a ministry subdivision.

We would ultimately recommend an independent regulator with a clear mandate focused on gas flaring reduction and potentially other upstream oil and gas activities. However this is a time consuming activity and in light of urgent action needed on setting up a gas flaring regulations in Egypt, we recommend, as an intermediate solution, the setting up of the regulator within the Ministry of Petroleum. We consider the conflicts of interest between the commercial interests of higher oil production and efforts to reduce gas flaring to be too significant for EGPC to continue playing the dual role of regulator and part owner of fields. This is underlined by the international examples assessed. If setting up a subdivision within a Ministry is unworkable, setting up a separate unit within EGPC may be satisfactory for the short- to medium-term. Over time we would expect to see this regulatory subdivision to become an own entity ideally self-financed and covering upstream regulation overall.

Table 7 Option evaluation table - Independence

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|-------------------|----------|---|-----------------------|--------------------------------|------------------------|
| Inde- pendence | Option 1 | Set up separate regulatory unit within EGPC | ✓✓ | ✓ | ✓✓✓ |
| | Option 2 | Regulation by ministry subdivision | ✓✓ | ✓✓ | ✓✓ |
| | Option 3 | Independent regulator | ✓✓✓ | ✓✓✓ | ✓ |

Box 8 Recommendation: Independence

Fulfilling the required regulatory scope while balancing the various potentially conflicting objectives requires that the ideal regulatory agency will have (once independently established or broken off from an internal regulatory team within a Ministry subdivision or EGPC itself):

- o The technical expertise to be able to establish and administer the recommended regulatory framework and, in particular, to manage the process of testing the economic and technical viability of associated gas utilisation.
- o The capability to either internalise the resolution of potentially conflicting objectives or to make representations on an equal basis to other agencies to an

entity who can resolve these conflicts.

- o Functional independence from other entities and interested parties. A number of best practice criteria for independence have been defined over time by organisations such as the World Bank and can be summarised as:
 - o The regulatory agency (RA) should consist of a commission supported by a secretariat.
 - o Commissioners should be appointed by or with the approval of parliament, should have clearly-defined qualification criteria, should be appointed for fixed terms and should only be prematurely dismissed on limited and well-specified grounds.
 - o The staff of the secretariats should be paid salaries that are on a similar level to their peers who work in the companies they are regulating.
 - o The RA should have effective decision-making powers without a need for other entities to review or approve these (subject, of course, to compliance with legal requirements) and should have the ability to enforce compliance with its decisions.
 - o The RA should be able to obtain the information they need to be able to make well-informed decisions.
 - o Funding should generally be from sources other than the government budget, in order to limit the risk that the agency's effectiveness and independence can be undermined through limits on its funds.

It is apparent that while gas flaring has a significant impact on the level of GHG emissions, it is not a sufficiently extensive activity (in economic terms) to justify creating a stand-alone Regulatory Agency to regulate it in the short term. We therefore recommend that as a short to medium term solution is for a separate subdivision within EGPC itself, to focus on gas flaring regulation (and potentially other upstream oil and gas regulation). Ultimately however, the RA should become an independent entity. This should be relatively easy to implement, as some regulatory functions are already partially covered by EGPC. So, this reform action would consist of pooling all resources at EGPC currently involved in regulatory matters into one unit.

Stakeholders

Stakeholders can play a central (and often positive) role in regulatory frameworks. We lay out three levels of engagement with stakeholders amid shaping gas flaring policy and regulation:

- o **Stakeholders consulted ad hoc** – A common theme from the case studies reviewed is a need for consistent and structured consultations with all the key stakeholders when devising gas flaring policy and regulation. This can be seen in the failures in Kazakhstan, where operators were surprised to find they suddenly had to cease all flaring, and Nigeria, where past flaring targets have

been dismissed as unrealistic by operators who had not been consulted. Ad hoc consultation, i.e. short notice and selective consultation of stakeholders, is likely to fall into the schematic of failed regulatory frameworks and be inadequate.

- o **Regular meetings with official stakeholder group** – The more successful case studies involve establishing an ‘official’ stakeholder group to facilitate collaboration on gas flaring for the long-term. The governmental body should avoid writing up targets and legislation behind closed doors and instead set up regular meetings to keep stakeholders updated and allow for stakeholder input. The regulator in Alberta, for example, has established a ‘Stakeholder and Government Relations Division’ in order to help create an enabling environment for stakeholder interactions with the regulator, as does Norway’s Miljøsoek. Regular meetings may also encourage stakeholders to set up an official group amongst themselves. Official stakeholder groups have been established in all three of our successful case studies: the Clear Air Strategic Alliance in Alberta, the Norwegian Oil Industry Association in Norway, and UK Oil & Gas in the UK. Collaborating with such organisations in drafting legislation and advising on the best regulatory approach ensures realistic targets are set, all stakeholders ‘buy in’ to the proposed approach, and that stakeholders have an outlet in which to have their concerns represented. However, setting up both an official stakeholder group and a division within a (yet to be established for Egypt) regulatory body for stakeholder engagement will require time to develop the necessary capacity.
- o **Formalised stakeholder interaction process** – A perhaps more important step than establishing regular contact with stakeholders is *formalising* stakeholder consultations. This would improve transparency by requiring the regulator to issue written statements on policy proposals that are then subject to a consultation process involving impact assessments and giving stakeholders appropriate time to respond. This would include giving stakeholders access to a formalised appeal process as well. Such frameworks are standard in formulating energy policies for all of our successful case studies and would help ensure any devised gas flaring policy framework has the backing of all relevant stakeholders. However, establishing a reliable consultation framework for policy formulation should be part of a wider government initiative, which would likely be an involved and lengthy process that would go beyond the scope of gas flaring policy alone.

In light of the good relationship between operators and the existing regulator, EGPC, we would recommend building on these relationships. A suitable vehicle for these consultations would be an official stakeholder group. Regular interaction with all operators on all aspects of regulations (targets, technical standards, procedures, metering provisions, etc.) should be done through meetings and in parallel to the sessions of the official stakeholder group. This will ensure ‘buy-in’ by the operators, create a collaborative regulatory environment, and ensure that realistic targets and standards are set. Consultation should also allow for timely responses from operators and a feeling that their views are taken seriously and incorporated into the regulatory framework as best possible. Where not possible, this should be explained clearly by the regulator.

Table 8 Option evaluation table – Stakeholders

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|---------------------|-----------------|--|-----------------------|--------------------------------|------------------------|
| Stakeholders | <i>Option 1</i> | Stakeholders consulted ad hoc | ✘ | ✘ | ✓✓ |
| | <i>Option 2</i> | Regular meetings with stakeholder group(s) | ✓✓ | ✓✓ | ✓✓ |
| | <i>Option 3</i> | Formalised stakeholder interaction process | ✓✓✓ | ✓✓✓ | ✓ |

Box 9 Recommendation: Stakeholders

We recommend consultation with stakeholders on a number of aspects. To facilitate this, we recommend the creation of a consultative committee on gas flaring. This would be chaired by the RA and would also include representatives of EGPC and the Ministry of Environment, as concerned government entities, and of industry representatives. The industry representatives should include both oil and gas producers and gas users. The membership should be balanced between government and industry representatives. The committee would meet at least twice-yearly and more often if required. This can be part of the development of a broader consultative framework in Egypt or it could serve as a ‘pilot’ example of how public consultations should be conducted.

5.2.3 Reform options: oversight framework

In order to ensure compliance with changes in the regulatory framework, an effective compliance and enforcement system needs to be established incorporating standardised approaches and methodologies to the measurement, calculation and reporting of flaring and emissions. The collection of consistent data will not only allow compliance to be assessed (and sanctioning of actions for non-compliance), but also to compare performance between operators, assess the effectiveness of the policy over time and to inform reviews of the objectives of government policy on flaring.

In all cases derogations could be applied for smaller fields in order to reduce the burden on operators, although it should be noted that higher accuracies should be maintained for large flares in order to reduce overall uncertainty in the data collected. Continued review of all aspects of monitoring and reporting by the consultative committee should be undertaken to help improve and streamline approaches.

As outlined above, the oversight framework is defined by the following processes and building blocks:

- o *Metering/measuring* – provides clarity on the volumes of gas flared and vented, which regulatory authorities and operators themselves can act upon;

- o **Reporting** – the process of sharing the collected data and information with the regulatory authority;
- o **Verification** – the process of verifying the completeness and accuracy of the data provided;
- o **Enforcement** – the tools and measures at the disposal of the regulatory authority to implement the regulatory framework and penalise non-compliance; and

Measuring/metering

Gas flaring measurement is handled differently across the jurisdictions reviewed. It is however a crucial aspect of any gas flaring regulation: only with precise data and information on the underlying causes of flaring can flares be reduced. We present two possible options that could be adopted in Egypt

- o **Precise methodology for estimating flares**– Flaring volumes do not need to be metered but can be estimated by adopting pre-defined methodologies. This is done in Alberta for operators with flaring volumes below a threshold volume. In Nigeria however this approach has been less successful, as the methodology and the verification of reported data was lacking in detail. Opting for a measurement approach over a metering approach requires the development of a precise and comprehensive methodology that needs to apply to all operators equally. Depending on the required accuracy, this could be a time consuming process. Additionally, the estimated flare volumes would have to be verified by the regulator making this a rather costly process in terms of regulatory effort.
- o **Technical standards and requirements for meters** – this is the approach adopted in mature regulatory gas flaring systems. Metering provisions exist in Alberta for the large majority of operations and the UK and Norway for environmental emissions, where very clear and sophisticated metering standards exist. There is a wide range of different types of meters, metering provisions and level of detail that can be specified in such technical standards. They provide a level playing field across operators and enable regulators to make decisions on the basis of a transparent and common flaring database. Inevitably, not every operation can retrofit gas meters, so conditions need to be specified for those operations, who can be exempted from the metering requirements (and required to measure/estimate their gas flares volumes). The regulatory costs associated with setting up technical standard for metering are relatively low. While the initial effort in designing the standards is high, ongoing verification is limited: inspections have to be conducted at sites regardless of the reporting system, checking that the meters meet the specified standards would therefore not be a substantial additional cost.

Table 9 summarises our assessment of the two different options against the three objectives we set out in Section 5.1.3. We recommend specifying minimum technical standards for metering provisions. These should be adhered if technically feasible to install or retrofit meters. If not technically feasible, the existing arrangements could continue to apply; however we would recommend a review of the existing arrangements by specifying a methodology to measure gas flaring volumes that applies to all. A detailed description on

suitable metering and measuring standards is provided by GGFR²⁸ and we would recommend adopting these as close as possible. This would effectively be a combination of both options with an emphasis on introducing minimum technical standards.

Table 9 Option evaluation table - Measuring/metering

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|------------------------|----------|-----------------------------------|-----------------------|--------------------------------|------------------------|
| Metering/ measuring | Option 1 | Methodology for estimating flares | ✓✓ | ✓✓ | ✓ |
| | Option 2 | Technical standards for meters | ✓✓✓ | ✓✓✓ | ✓✓ |

Box 10 Recommendation: Measuring/metering

We recommend a combination of technical minimum metering standards as well as precise methodologies for estimating flares. This approach to metering should cover the following aspects:

- o *Approaches to measurement for different types of flaring activities.* This could include identification of the flare gas sources that must be measured, requirements for metering of such sources, the use of alternative measurement techniques such as “by difference” approaches, and the required accuracy of measurement, including for different size flares.
- o *Requirements for gas compositional analysis.* This would include sampling frequencies, required parameters to measured, and analytical standards to be met.
- o *Standardised methodologies to calculate GHG emissions from flaring.* A range of methodologies may be used to convert flare gas volume, mass and composition data into GHG emission estimates. Such methodologies should be standardised for all operators to ensure that a consistent and comparable time series is collected, and also to align reporting with international standards such as under the UNFCCC.

Metering devices should be gradually introduced to replace the current approach of estimating flared gas volumes. Meters would initially be introduced for those fields with the highest flare volumes (fields with flared volumes exceeding 1 mmscfd and sufficient reserves to sustain plateau flaring over 3-5 years). The use of higher accuracy (and higher cost) meters should be restricted to high flare gas locations.

²⁸ *Guideline on Flare and Vent Measurement*, GGFR, 2008 available at: www.worldbank.org/en/programs/gasflaringreduction#5

Reporting

The process of reporting needs to be clear to the regulator and most importantly to the operators. Details that need be covered when setting out a reporting framework are frequency of reporting, format of reporting, content of reporting and consequence of failure to report data. These are too detailed to be covered in this Report; however in the jurisdiction reviewed, one can largely distinguish between two different types of reporting:

- o **Self-reporting** – under this option, the responsibility lies with the operator alone to report their flaring volumes. This is the most common method across international gas flaring regulatory frameworks. It minimises the regulatory supervisory costs and brings operators to play an active role in the regulatory process. International best practice shows that successful self-reporting frameworks give precise conditions under which reporting has to take place. This can be by requiring operators to submit all information in a template so that the regulator has equal level of detail and formats across all operations. This could go as far as having an online portal where data can be updated by operators.
- o **Data collection by on-site regulators** – an alternative approach to self-reporting is a more restrictive regulatory approach focusing, whereby meter readings and inspections are done by external inspectors. The operator has therefore no role to play in the reporting process. This is not a common approach applied internationally due to the high cost of this approach: a large number of inspectors would have to be on-site on a very frequent basis. Additionally, it does not tie-in operators into the reporting process thereby creating a regulatory environment that is not focused on collaboration but on confrontation.

The current gas flaring system in Egypt is based on self-reporting and we would recommend to maintain it this way. The large number of remotely located operations do not make an inspection-based reporting framework feasible. However the existing reporting requirements need to be reviewed and there should be a more detailed outline of the information and format needed for reporting. Depending on the measurement/metering provisions, the content of the reporting requirements should also be adjusted. To achieve economies of scale, the reporting requirements for gas flaring could be combined with the reporting requirement for upstream regulation as well environmental regulation. This would minimise the reporting costs for the operator and would force collaboration between the various upstream regulatory institutions in Egypt.

An additional measure that can be introduced in Egypt's reporting process is the publication of all data on public platforms. This creates full transparency and allows firstly the wider population and local resident to assess the degree of pollution for which their local operator is accountable. Secondly, it applies pressure on those operators with high flaring levels to take corrective measures quickly. Thirdly, it creates competition between operators to reduce flaring levels to show that they are trying to reduce gas flaring, which can also then be highlighted as a matter of corporate social responsibility. This would not be a particularly onerous process, but could potentially yield benefits

Table 10 Option evaluation table - Reporting

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|-----------|----------|---------------------------------------|-----------------------|--------------------------------|------------------------|
| Reporting | Option 1 | Self-reporting | ✓✓ | ✓✓ | ✓✓✓ |
| | Option 2 | Data collection by on-site regulators | ✓✓✓ | x | ✓ |

Box 11 Recommendation: Reporting

We recommend for operators to continue to be responsible for reporting their gas flaring volumes. The provisions on reporting should include:

- o **Standard reporting formats.** Standard reporting formats will ease data collation activities by the RA, as well as making it clear for operators exactly what data they are required to submit. Reporting templates should be developed for production, gas composition, reservoir parameters, and daily feed and product production in treatment facilities.
- o **Standard reporting frequencies and deadlines for report submissions.** A standardised frequency for reporting will be required, preferably aligned with other reporting and compliance activities required under the new regulation (e.g. economic assessment).
- o **Data collection:** Data should be collected on a field-by-field basis rather than company-by-company. In the case of manual estimate of volumes, uniform methodologies should be set. Guidelines should be set for calibration and data collection by meter type.

In addition, we recommend an annual summary of flaring and venting data is published, showing quantities by field and by operator and the location of each field and flare stack. This will provide incentives for operators to reduce flaring and venting volumes over time, as well as helping third parties who are interested in utilising currently flared gas. The data collected by the RA on flaring and venting should also be provided to the Ministry of Environment for the purpose of monitoring compliance with environmental restrictions on flaring.

Verification

In the verification process two main objectives are pursued. Firstly, the completeness of data provided by operators is assessed. Secondly the accuracy of data provided is verified. There are largely two different approaches to implement verification processes.

- o **Desk based verification only** – data received from operators is verified by the regulator for completeness. The data is then either manually, or with the help of software, assessed for any major changes compared to the last entry. This process relies on trust and close collaboration between operators and regulators.

None of the reviewed case studies have adopted this principle explicitly. It will usually be supported by a system of inspections to verify whether the data reported is correct. In Nigeria, the serious underfunding of the regulator and the lack of legal support to access operator’s data and premises, means that de facto desk based verification process is in place and is a large part of the reason for gas flare volumes in Nigeria being high. The software for automatic verification is very costly, so unlikely to be implemented for a newly established Egyptian upstream regulator.

- o **Desk based verification supported by inspections** – this is the most common approach adopted across successful gas flaring reduction regimes. The first step for regulators is to verify the completeness of data reported. This will then be assessed by regulatory staff for any inconsistencies and sharp changes in gas flaring volumes. On that basis a first assessment of non-compliance with reporting requirements can and should be made. However to verify the accurateness of the data provided, inspections of sites is vital. Inspections can cover a range of different aspects: checking for accuracy of meter readings, assessing whether any technical standards are met, assessing whether operators comply with environmental regulations and assessing whether investments as part of the field development plan are indeed being undertaken. This will give the regulator reassurance and transparency that operators are in full compliance with the gas flaring (or indeed) other regulations.

We strongly recommend setting up a system whereby the first verification tool is a desk based review of reported data checking for anomalies and completeness of the data. The second tool, to be developed in parallel with desk based verification, is an inspection system. Inspection systems and schedules can however be costly and time consuming. It would therefore be advisable to have a system in place that minimises costs and maximise effectiveness. This can be done by a targeted inspection approach, where those operators with a recent history of non-compliance are targeted first. Or those operators with the highest flaring levels and/or highest risk criteria of flaring to be prioritised as part of the inspections. Additionally, geographical consideration should be taken. In Alberta, the regulator has regional offices. This may not be needed for Egypt at this stage, but clustering inspections by location of fields will reduce the costs of such inspections considerably. More details would have to be developed for a successful inspection system (e.g. procedures during inspections, announced vs. unannounced inspections, legal backing for regulators to access the premise). Regardless in what format, inspections are vital for successful gas flare reduction regulatory frameworks.

Table 11 Option evaluation table – Verification

| | | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation |
|--------------|----------|---|-----------------------|--------------------------------|------------------------|
| Verification | Option 1 | Desk based verification procedures only | ✓ | ✓ | ✓✓✓ |
| | Option 2 | Desk based verification and inspections | ✓✓✓ | ✓✓✓ | ✓✓ |

Box 12 Recommendation: Verification

The extent to which third party verification of flare gas data could be employed should be reviewed by the consultative committee to consider the potential benefits to the regulator, and the potential costs to operators.

A quality assurance system should be established that includes periodic audits of compliance with requirements, with the frequency of such audits related to an operator's historical compliance. The impetus for on-site visits would also be partially decided by the setting of acceptable accuracy ranges (e.g., $\pm 5\%$) when checking data validity and the acceptable range for data value variation.

Enforcement

No regulatory framework is successful without adequate enforcement mechanisms. Nigeria and Kazakhstan are examples where low penalties and lack of enforcement of these penalties have held back the efforts of gas flare reduction significantly. Particularly at the introduction of gas flare regulations. Enforcement is however not only about the level and type of penalties. It is as much about giving regulators the necessary legal backing to charge penalties and demand the payment. Public government support to the regulator is also a vital pre-requisite.

There are broadly two reform options to enforce regulations:

- o **Volume based penalty** – this is akin to a tax and is therefore similar to the CO₂ tax in Norway or indeed the EU ETS scheme that both Norway and UK have adopted to reduce CO₂ emissions including gas flaring. The volume based penalty is easy to apply and straightforward to calculate. The success of this type of arrangement crucially hinges on the level of the penalty. More often than not, these penalties are however not set sufficiently high and influenced by policymakers to not jeopardise other policy goals (e.g. increased oil production). Additionally, this type of system does not lend itself to a flexible and targeted approach to reducing flaring, as it values every unit of gas flared equally. However, some operators warrant harsher punishment than others due to, for example, their non-compliance history, their location, or the nature of the flares. Additionally, volume based penalty enforcement system will typically have monetary penalties. While this can be successful, it lends itself to setting these penalties arbitrarily and lacks flexibility in adjusting penalties to the degree of non-compliance.
- o **Flexible penalties based on non-compliance event** – a more flexible approach, but more difficult to implement, is an enforcement system that sets penalties on the basis of a number of factors including for example the severity of non-compliance. Under such a system penalties need not only be monetary. They could include production shut-ins, investment requirements, or oil price discounts. The unique and most successful such enforcement system has been implemented in Alberta, where the regulator applies a non-compliance matrix to the event and can then take appropriate enforcement measures. More details on this system are summarised in Section A1.1.2 in the Annex.

The success of one enforcement system over the other will depend on the level of penalties. However to maintain flexibility in the enforcement system we would recommend introducing elements based on the non-compliance event. It falls in line with a targeted approach we recommend for the verification system and allows for flexibility to be built into the regulatory framework. As non-compliance is gauged based on site specific techno-economic feasibility studies, permits and if applicable exemptions, having a penalty that matches the specific non-compliance event follows logically. Alternatively, a flat volume based penalty system could be introduced at inception of the regulatory framework. Over time however the system could be adjusted to include more flexible elements.

Table 12 Option evaluation table - Enforcement

| | | Impact on APG flaring | Success in other jurisdictions | Ease of implementation | |
|--------------------|-----------------|--|--------------------------------|------------------------|-----|
| Enforcement | <i>Option 1</i> | Volume based penalty | ✓✓ | ✓ | ✓✓✓ |
| | <i>Option 2</i> | Flexible penalties based on non-compliance | ✓✓✓ | ✓✓✓ | ✓ |

Box 13 Recommendation: Enforcement

Flaring and venting volumes in excess of those permitted (where the excess is not due to safety-related reasons) would be subject to penalties, levied as a charge per unit of excess gas (measured on a standard basis) flared or vented. The level of the penalty should be determined by the RA and revised periodically. We propose that it should be related to some external measure of the damage done by flaring, to avoid concerns among stakeholders that the penalty may be either arbitrary or set at excessively high levels. Possible benchmarks for the penalty are:

- o The market value of the flared gas, which might be set equal to import LNG prices.
- o The environmental damage caused by the flared gas. The US Environmental Protection Agency’s Social Cost of Carbon could be used as an external benchmark.²⁹

A procedure will need to be defined which describes how enforcement actions will be taken in the event that data shows non-compliance with the flare gas reduction objectives. Fines would apply for matters such as incorrect or false reporting, failures to report, incorrect economic tests, failures to submit economic tests or failures to comply with minimum technical standards. We recommend that a first offence in each case generally only leads to a notice of non-compliance and a requirement to correct the failure within a given period. However, such an offence would lead to increased monitoring of compliance of the operator concerned. Persistent offences will attract increasing fines and much closer future scrutiny. Also, a penalty system for late submission will need to be introduced in order to incentivise operators to make timely submissions of data.

²⁹ See <https://www.epa.gov/climatechange/social-cost-carbon>

5.3 Wider gas sector reforms

The success of the introduction of a gas flaring regulatory framework would be further improved by creating additional ‘pull factors’ for gas flare reduction investments, i.e. reforms improving the economic feasibility of such investments. These reforms are however wider market reforms that will affect the gas sector and market in general not just gas flaring. These reforms are potentially substantial and some are already planned in the New Gas Market Law and supporting documentation including ECA’s report published in April 2016 *Egypt gas market reforms and pricing principles*.. Once implemented these will have positive impacts on gas flaring reduction, but evidently will not be a guarantor. A suitable regulatory framework still needs to accompany these reforms.

Pricing of gas/APG

To make investments in gas flare reduction economically attractive, wholesale gas prices in Egypt need to increase and become cost reflective. Despite recent gas price increases, the largest consumer group, power generators, still pay very low gas prices. This is largely due to low electricity prices as well. A gas and electricity pricing reform is therefore needed to incentivise APG flare reduction. As estimated in the EBRD study preceding this study³⁰, an electricity price increases of 10 US\$/MWh could improve the IRR of gas to power projects by just over 5%.

Several gas price adjustment options exists. Two pricing reform options are worth briefly highlighting here:

- o **Marginal cost pricing** – this is most consistent with introducing competition and ensures cost recovery and financial viability for the public supplier, providing incentives for increased production and facilitating security of supply. However, the impact on end-user prices could be significant, particularly if marginal cost is set in accordance with LNG imports.
- o **Netbacks & Weighted Average Cost of Gas (WACOG)** – this entails the application of netback prices for industries and other uses where price exceeds the cost of supply, and WACOG prices for the remaining sectors. This mechanism also ensures full cost recovery and is consistent with market opening for industrial customers, in particular, but could result in those customer groups on WACOG prices remaining in the regulated market.

An option to incentivise APG utilisation would be to price APG differently to other gas streams. However we would not recommend this to be a viable alternative. Firstly, setting a price for APG is arbitrary, as each stream of APG will have separate costs. It is better to allow each operator to negotiate their bilateral contract with potential offtakers individually and enable access to the market. Secondly, this would raise wholesale gas price even further, as APG would have to be priced sufficiently high to recover utilisation investments. Without an adequate pricing reform (as noted above), this would put additional financial strain on the sector.

³⁰ *Associated Petroleum Gas Flaring Study for Egypt* completed by Carbon Limits in January 2016

PSC terms

As noted in section 3.1, the existing PSC terms are not well suited for gas flaring investments in the changed petroleum production landscape in Egypt. The constraints identified in previous sections of the report highlight the fact that the existing regime is not best suited to APG flaring reduction. No explicit gas flaring investment clauses exist and consequently, all constraints identified affect all investments, not just gas flaring investments. However changing the entire cost recovery mechanism and all PSC terms just for the purpose of gas flaring reduction seems excessive and unrealistic. Implementing such changes can be lengthy and cumbersome requiring extended negotiations, legal proceedings and parliamentary approval. We would therefore not suggest PSC reforms to be the main thrust of regulatory changes for gas flare reduction. A suitable regulatory framework is needed in any case, and starting with setting this up will be less controversial and time consuming than renegotiating PSC terms or adding new clauses to the contracts.

Should the Government nevertheless decide to adjust PSC terms to incentivise gas flaring reduction investments more, the following changes could be considered by policymakers:

- o **Separate cost recovery mechanism for gas flare reduction investments** – one of the challenges in existing terms is that operators are not guaranteed cost recovery of investments, due to the limited annual CAPEX recovery allowed. Allowing for separate CAPEX recovery terms for gas utilisation projects, if favourably designed, could incentivise investments in gas flared reduction.
- o **Allow for EGPC to participate in gas flare reduction investments** – besides the difficulty of cost recovery under existing terms, the investment decisions for EGPC and contractor not always aligned as per the existing PSC. To overcome this, EGPC could be allowed to participate in investment decisions associated with APG gas flare reduction. This may also facilitate access to finance for operators, as the overall financing requirements would be reduced with EGPC contributing to the investment outlay. EGPC involvement, as Government owned entity, may also reduce the credit risk for the project.

Third Party Access (TPA)

As per the New Gas Market Law (see section 2.1.3), non-discriminatory access to transmission networks for eligible consumers will be granted in Egypt. This will help for APG gas flare investments, as it will enable large consumers to negotiate gas supply contracts with operators directly. This can give security of supply to consumers (depending on the nature of gas flaring that is captured) and allows for operators to negotiate prices that are cost reflective. Although this will not, on its own, lead to gas flare reduction investments, it may contribute to the economic feasibility of some investments. It is also likely to trigger operators in making economic assessments of their different utilisation options, as it will provide them with access to a wider variety of potential offtakers. Third Party Access will therefore influence gas utilisation positively and for the purpose of gas flaring should be pursued.

Gas market structure

Closely linked to TPA is the gas market structure. Unless operators can circumvent the single buyer of gas, TPA has limited benefits. So, breaking up the market into a regulated and a deregulated component should be done in parallel with passing TPA provisions. From our understanding of the draft New Gas Market Law, this is indeed the case. This provides operators the option to identify those consumers that are eligible to negotiate contracts bilaterally. When reforming the market structure a number of factors will need to be considered and aligned with the proposed market structure including security of supply, degree of competition to be achieved, pricing considerations and private sector participation throughout the sector.

6 Prioritised regulatory reform options

This section combines our findings to recommend a set of regulatory changes suitable for Egypt. The recommended reform options are intended to form a starting point for policymakers to design a more detailed regulatory framework at later stages. This section also includes a roadmap of actions for implementation and an initial time schedule.

6.1 Core reform options

Table 13 summarises the recommendations made in the previous section providing an overview of all the reform options needed for a well-developed regulatory framework.

Table 13 Overview of recommended bundle of reform options

| | |
|------------------------------------|---|
| Targets | Industry-wide target acting as a medium term objective for the entire sector – these are not binding but will serve as indicator to redesign the framework if targets are not met |
| Flaring permits | Permits for exceptional flaring if above threshold value or if flare reduction not economic or technically feasible |
| Economic test | Operators need to assess the economic feasibility of gas utilisation investments on a frequent basis – if above threshold value, operators are required to make the investment |
| Investment approval process | Implement a transparent decision tree outlining each step required for gas flare reduction approvals, the necessary documentation and the relevant government entity to obtain approval from. |
| Minimum technical standards | Minimum technical standards operators need to abide by for those flaring activities that are permissible |
| Independence | Discontinuing EGPC's role as regulator; regulatory activities initially embedded into Ministry as sub-division. Ultimate objective should be for regulator to be independent. |
| Regulatory scope | The new regulatory entity should have full regulatory responsibility for flaring, i.e. monitoring, evaluation, verification and enforcement |
| Stakeholders | Stakeholder engagement should be a key component of the regulatory framework and regulatory processes |
| Metering/measuring | Technical standards and requirements for meters. Where not feasible to install meters: determine precise methodology for estimating flares |
| Reporting | Self-reporting within transparent and clearly defined reporting requirements |
| Verification | High level, desk-based verification of reported data complemented with targeted inspections based on probability of non-compliance and health or environmental impacts. |
| Enforcement | Penalties based on severity of non-compliance |

Implementing the full set of options (together with the wider market reform changes) would be tantamount to implementing a full revised regulatory framework. This may be out of the scope of the GoE and may only yield significant benefits in terms of gas flaring reduction at a later stage.

We therefore recommend focusing on a selection of the recommended reform options ('prioritised reform options') that can be implemented more quickly and are likely to have a significant impact on gas flaring levels. The core reform options we recommend focusing on initially are:

- o ***Core reform option 1: economic test*** – the implementation of the economic test that determines whether an investment should be pursued by operators or not.
- o ***Core reform option 2: transparent investment approval process*** – setting up a decision tree with clear instructions of what to submit at which stage of the application process and who to submit it to.
- o ***Core reform option 3: regulatory independence*** – operations and regulations should be separated and establishing a separate regulatory unit at EGPC would be the first step toward a fully independent regulator.
- o ***Core reform option 4: metering standards*** – the implementation of minimum metering standards, which have to be complied with if technically feasible. If not, clear measurement methodologies need to be set out.
- o ***Core reform option 5: stakeholder engagement*** – a formalised process of engaging stakeholders in decision makings and allowing stakeholders to file complaints about regulatory proceedings
- o ***Core reform option 6: policy commitment for reducing APG flaring*** – GoE needs to show commitment in reducing gas flaring by passing a gas flaring policy outline the objectives it wants to achieve and the principles it wants to follow in reducing gas flaring.

6.2 Roadmap of implementation

The previous sections highlighted the prioritised reform options for improving the gas flaring regulatory framework drawing on international best-practices. The implementation of the reform options outlined will however require a concerted effort by all stakeholders and the proposed reforms are ambitious.

Presently awareness is low and activities to tackle APG flaring have been fairly limited. It is therefore critical to establish a coherent plan through which to tackle the issue in a structured way that takes due account of the on-the-ground realities and avoids imposing unrealistic near-term expectations upon GoE and operators alike.

For these reasons, we propose a three-phase strategy that charts what we feel is an orderly and coherent route to a more transparent and effective regulatory framework of flaring activities. The phases are as follows:

- o Phase 1: Piloting APG flaring reduction;
- o Phase 2: Review and Strategy Development; and
- o Phase 3: Implementing the agreed Strategy.

The core components of each phase are described in greater detail below.

6.2.1 Phase 1: Pilot Scheme

We propose that the starting point for addressing gas flaring should be the establishment of a Pilot Scheme that helps to gain experiences with implementation and supports operator readiness for revised approaches for APG management over the medium-term. A demonstration programme acts as a ‘soft-start’ rather than jumping straight to a regulatory approach, which may prove challenging to implement. We suggest that such a phase should last 3 years, and involve implementation and testing of a number of the core elements described in Section 6.1, but focussed only on a selected number of sites in a single geographical region (e.g. a group of fields in the Western Desert such as Badr El Din complex, Abu El Gharadiq complex or in the north west area around Salam). The choice of area should be driven by the poorest performance to date, and should focus on the less mature provinces where investment may still be feasible. This suggests the north western area of the Western Desert would be the most likely candidate³¹. The choice should also be guided by practical realities in terms of operator willingness and ease of access and implementation for EGPC acting in the capacity of the regulatory agency.

The core elements to be established and tested in the pilot-phase include:

- o Economic tests, including clustering analysis (*Core reform option 1*)
- o Investment approval process (*Core reform option 2*)
- o Institutional competencies, procedures and protocols used by EGPC for reviewing and evaluating reported data and communicating with operators (*Core reform option 3*)
- o Gas flare metering and measurement guidelines and reporting protocols for APG flaring (*Core reform option 4*)
- o The proposed stakeholder platform through which to develop approaches for APG flaring reduction (*Core reform option 5*)

In implementing the Pilot Scheme, we would suggest the following steps:

Step 1 – National Stakeholder Workshop

The initial step should be the holding of a national workshop on APG flaring with all interested stakeholders. The workshop would provide an opportunity for Government to express its views and plans for tackling APG flaring, including presenting the results of the

³¹ *Associated Petroleum Gas Flaring Study for Egypt*, Carbon Limits, EBRD, 2016

recent EBRD-sponsored studies. It would also present the opportunity to garner views from industry regarding the barriers and opportunities presented to reducing flaring in the country.

The first key outcome of the workshop should be agreement on the fields to be covered in the Pilot Scheme. A second key outcome should be the establishment of the membership of a *National Associated Petroleum Gas Flaring Consultative Committee (GFCC)*, and a date for its first meeting (within 6 months of the workshop). The GFCC should consist of relevant Governmental representatives (EGPC, MOP, MOE) and operators included in the pilot-phase, plus any other operators wishing to participate on a voluntary basis. It will provide the forum for rolling out all subsequent actions in the Pilot Scheme.

In organising the workshop, it will be incumbent upon EGPC to nominate staff for the committee that can act as the secretariat function for implementation of the entire Pilot Scheme.

Step 2 - Gas flaring policy

A key outcome of the first step should be the determination of a gas flaring policy. GoE should set out its gas flaring objectives and key principles determining the framework that will define the implementation of the reform options. Besides objectives and key principles, the policy should also contain targets, institutional responsibilities, time frames and operators' responsibilities. This will demonstrate the full commitment of GoE behind gas flare reduction and its objective to maximise domestic energy resources for domestic usage.

Step 3 - Initial Actions

At its 1st meeting (to be held within 6 months of the National Workshop), the GFCC should work to establish two key elements:

1. **Common measurement and reporting protocols and guidelines** – these can draw on both methods currently used by operators, and international standards and protocols. Once agreed, the guidelines shall be used by all operators during the Pilot Scheme for the measurement and reporting of gas flaring. We recommend that the approach involves daily monitoring, at least quarterly sampling of gas composition, and at least quarterly reporting of gas flaring in a daily time series format.
2. **Flare permitting system** – the Pilot Scheme should be used to establish a provisional permitting system by which flaring is allowable. The purpose would be to test the feasibility for setting permitted levels of flaring, and to develop the format of the permits.

In parallel EGPC will need to establish systems for storing and analysing data reported by operators and for logging the flaring permits issued.

It may also be good practice at this stage to consider establishing a flare reduction target to be achieved in the Pilot Scheme, although this may not be absolutely necessary. The role of a target should be considered in consultation with operators at the first GFCC meeting.

To ensure the best international practice is adhered to, international study tours should be organised to other regulators for EGPC staff.

Step 4 – Enhanced Actions

Following 6-12 months of reporting using the guidelines and the implementation of the permits established under Step 2, the GFCC should meet again to discuss how implementation is going and to consider enhancements to the scheme. Key enhancements include:

1. **Economic tests including cluster analysis** – use of testing as described previously can provide a way to encourage ongoing consideration of flare reduction opportunities. They require common methods and protocols to be employed by all operators and should include requirements to assess economies of scale achievable by clustering (i.e. considering all flaring and venting within proximity of a site). Alberta uses such tests and can be found in the public domain.³²
2. **Minimum technical standards for flares** - this should be introduced and incorporated into revised flare permits for future years of operation of the Pilot Scheme. Again, Alberta provides example of standards that are available in the public domain.³³

In the lead-up to the 2nd GFCC meeting, EGPC (and other secretariat staff) should review the economic protocols and technical standards used in other jurisdictions – primarily Alberta – and evaluate whether they could be applied directly and/or what modifications would be needed to fit to local circumstances. As part of this preparation, it may be prudent for members of the GFCC secretariat to undertake outreach activities with third parties that have greater experience in APG flaring regulation, and undertake a study tour to those jurisdictions to learn from their experiences. This could provide an opportunity for first-hand learning about measurement protocols, data management and evaluation, economic testing and technical standards.

EGPC should share a briefing note on economic testing and technical standards ahead of the 2nd GFCC meeting, and present its findings and the proposed way forward at the meeting. The economic testing protocol and technical standards should be agreed at the 2nd GFCC and rolled out to pilot-scheme operators thereafter, with new flare permits issued incorporating minimum technical standards. The economic tests should be completed by all Pilot Scheme operators within 3-6 months of the meeting.

An inspection of Pilot Scheme facilities should be undertaken within the period 0.5 to 1 year after the 2nd GFCC meeting to assess implementation of the Pilot Scheme technical elements.

Step 5 – Progress Review

A 3rd GFCC meeting should be held 1 to 1.5 year after the 2nd meeting. The purpose of the meeting would be to discuss experiences and exchange information in terms of:

³² Section 2.9 of Directive 060. Alberta Energy Resources Conservation Board.

³³ Section 7 of Directive 060

- o Measurement and reporting (guidelines, data quality, reporting and analytical issues)
- o Results of economic tests (ease of implementation, any modifications to be employed, results of analysis and planned actions arising from test results)
- o Technical standards (issues and effectiveness; costs of meeting the standard)
- o Results of inspections carried out
- o Plans for remainder of pilot-phase (covering 1.5 to 2 years or so of further operation).

Other items to be established include the timing of the next economic evaluation test, the timing of the next meeting, and any other issues that need addressing. At least one further round of economic tests should be completed within the Pilot Scheme.

Step 6 – Pilot Scheme Final Review

A 4th and Final GFCC meeting should be held where results of the Pilot Scheme are discussed amongst participants. The meeting should focus on:

- o Lessons learned on measurement, economic testing, technical standards etc.
- o Investments made and flare reductions achieved
- o Strategies for wider roll-out of the experiences.

Outcomes of the Final GFCC meeting should be used to inform the strategy for moving forward with a wider flare reduction programme across the entire sector in Egypt.

6.2.2 Phase 2: Review and Strategy Development

Following completion of the Pilot Scheme, GoE will need to decide on how it wishes to pursue further efforts to reduce APG flaring across the entire petroleum sector in the country. The strategy will need to be informed by experiences gained in the Pilot Scheme in terms of:

- o Effectiveness of methods, systems, protocols and other tools developed during the Pilot Scheme;
- o Effectiveness of the Pilot Scheme in delivering any measurable improvements in APG flaring; and,
- o Effectiveness of reforms achieved through the New Gas Law in incentivising investment into APG recovery.

During the review it will be important to consider performance of operators included in the Pilot Scheme relative to those outside drawing on examples of effective reductions in gas flaring.

Based on this review, a decision should be made regarding the strategy to be taken to managing APG flaring going forward. The most critical decision to be made is to decide whether there is a need to either (i) introduce regulation in order to effectively manage APG flaring, or whether (ii) a national roll-out of the Pilot Scheme approach as a voluntary scheme would be equally effective. In the case of the latter, the ongoing threat of regulation can act as a powerful motivator for participation and compliance with the voluntary scheme absent of the need to go through the process of developing regulations.

The decision on how to proceed should be made within 6 months of completing the Pilot Scheme i.e. within 6 months of the final GFCC meeting.

6.2.3 Phase 3: Implementing the Agreed Strategy

Following the review and decision on APG flaring reduction strategy (voluntary or regulatory), the next phase will be implementing the agreed strategy. In practice, the procedures needed to implement the strategy should be same regardless of the choice since any effective voluntary scheme will require rules and oversight arrangements on a par with a regulatory approach. In implementing either approach, the following elements will be needed:

- o **Establishing a target for APG flaring reduction** – this can be informed by performance improvements achieved in the Pilot Scheme.
- o **Formalising methods, protocols, permits etc** – this can draw on the Pilot Scheme experiences.

In implementing a voluntary approach the elements described could be codified in a voluntary *Code of Practice* to be signed by all operators. In selecting a regulatory approach, additional factors for consideration will include:

- o Use and level of penalties;
- o Drafting the legislation and passing it through the Egyptian legislative process;
- o Formalising institutional arrangements for oversight and enforcement.

A schematic overview of the proposed Roadmap is presented below (Figure 14).

Figure 14 Schematic of Gas Flaring Reduction Roadmap

| Reform action | Lead entity | Start date | Duration months | 2017 | | | | 2018 | | | | 2019 | | | | 2020 | | | |
|--|--------------|------------|-----------------|------|---|---|---|------|---|---|---|------|---|---|---|------|---|---|---|
| | | | | J | F | M | A | M | J | J | O | N | D | J | F | M | A | M | J |
| Phase 1: Pilot Scheme | | | | | | | | | | | | | | | | | | | |
| #1 National Stakeholder Workshop | | | | | | | | | | | | | | | | | | | |
| Establish Pilot Scheme area + GFCC | MoP/EGP | Jul-17 | 2 | | | | | | | | | | | | | | | | |
| #2 Gas Flaring Policy | | | | | | | | | | | | | | | | | | | |
| Publish and draft gas flaring policy | MoP/EGP | Sep-17 | 3 | | | | | | | | | | | | | | | | |
| #3 Initial Actions | | | | | | | | | | | | | | | | | | | |
| 1st Meeting of GFCC - Establish Measurement Protocol - Establish Flare permitting system | GFCC | Sep-17 | 3 | | | | | | | | | | | | | | | | |
| Roll out Measurement Protocol | Operators | Dec-17 | 12 | | | | | | | | | | | | | | | | |
| Roll out Permitting system | EGPC | Dec-17 | 3 | | | | | | | | | | | | | | | | |
| Compile data logging and evaluation system | EGPC | Dec-17 | 3 | | | | | | | | | | | | | | | | |
| Research & Study tours on economic tests etc. | EGPC | Jan-18 | 8 | | | | | | | | | | | | | | | | |
| #4 Enhanced Actions | | | | | | | | | | | | | | | | | | | |
| 2nd Meeting of GFCC - Economic Tests - Minimum Technical Standards | GFCC | Jul-18 | 1 | | | | | | | | | | | | | | | | |
| Roll-out Economic Tests | EGPC | Aug-18 | 2 | | | | | | | | | | | | | | | | |
| Roll-out revised Permits with Technical Standards | EGPC | Aug-18 | 2 | | | | | | | | | | | | | | | | |
| Implement Economic Tests and return results | Operators | Sep-18 | 4 | | | | | | | | | | | | | | | | |
| Review and evaluate first economic tests | EGPC | Jan-19 | 2 | | | | | | | | | | | | | | | | |
| Inspect Pilot Scheme facilities | EGPC | Mar-19 | 2 | | | | | | | | | | | | | | | | |
| #5 Progress Review | | | | | | | | | | | | | | | | | | | |
| 3rd Meeting of GFCC - Information exchange | GFRC | Aug-19 | 1 | | | | | | | | | | | | | | | | |
| Implement Economic Test and return results to EGPC | Operators | Dec-19 | 1 | | | | | | | | | | | | | | | | |
| Review and evaluate second economic tests | EGPC | Jan-20 | 1 | | | | | | | | | | | | | | | | |
| #6 Pilot Scheme Final Review | | | | | | | | | | | | | | | | | | | |
| 4th Meeting of GFCC - Final Information exchange - Strategy discussion | GFRC | Apr-20 | 1 | | | | | | | | | | | | | | | | |
| Phase 2: Review and Strategy Development | | | | | | | | | | | | | | | | | | | |
| Develop strategy for wider roll-out: - Voluntary scheme; or - Regulatory scheme (mandates) | MoP, EGPC | May-20 | 3 | | | | | | | | | | | | | | | | |
| Phase 3: Implement Agreed Strategy | | | | | | | | | | | | | | | | | | | |
| Implementation | All | Sep-20 | 5 | | | | | | | | | | | | | | | | |

A1 Annex: case studies

A1.1 Country case study 1: Alberta

A1.1.1 Overview of sector and regulations

Sector overview

In 2015, Alberta's total oil reserves were 166.8 billion barrels³⁴, amounting to close to 10% of total global oil reserves³⁵. Alberta accounts for 98% of Canada's oil reserves and ranks third in the world in terms of proven crude oil reserves, after Saudi Arabia and Venezuela. The majority of oil reserves (99%) come from oil sands. Alberta's oil sands reserves are one of the largest in the world.

In 2015, Alberta's established reserves of natural gas amounted to 31.3 trillion cubic feet (Tcf). Total marketable natural gas production reached an average of 10,009 mmcf/d in 2016, almost 80% of natural gas production in Canada. The top three producers in Alberta's natural gas industry are Canadian Natural Resources Ltd, ConocoPhillips Canada, and Encana Corporation. Virtually all exports go to the United States.

Reducing routine flaring and venting of associated petroleum gas (APG)³⁶ has been a priority in Alberta since 1938, the year the Turner Valley Gas Conservation Board (the early predecessor of the AER) was formed to address reservoir management problems in southern Alberta.

Over time, gas flaring and venting levels in Alberta have passed through different stages. Until the mid-nineties, increasing oil production and relatively soft regulation led to increasing flaring and venting volumes. Since then, however, gas utilization rates have improved, due to two main factors:

- o **Commercial incentives**— oil producers faced more developed gas markets which enabled them to profitably market associated gas. Also, associated gas became more valuable due to its use in enhanced oil field production, made possible by technological progress in gas capturing and reinjection processes.
- o **Tighter environmental regulation**— the Clean Air Act was passed in 1971 and Alberta's Ambient Air Quality Standards were set as a consequence, regulating gas flaring and venting.

In the mid-nineties, concerns about flaring prompted the Energy and Utilities Board (EUB) (also a predecessor of the AER) and Alberta Environment (now Alberta Environment and

³⁴ Alberta's Energy Reserves 2015 and Supply/Demand Outlook 2016–2025, The Alberta Energy Regulator.

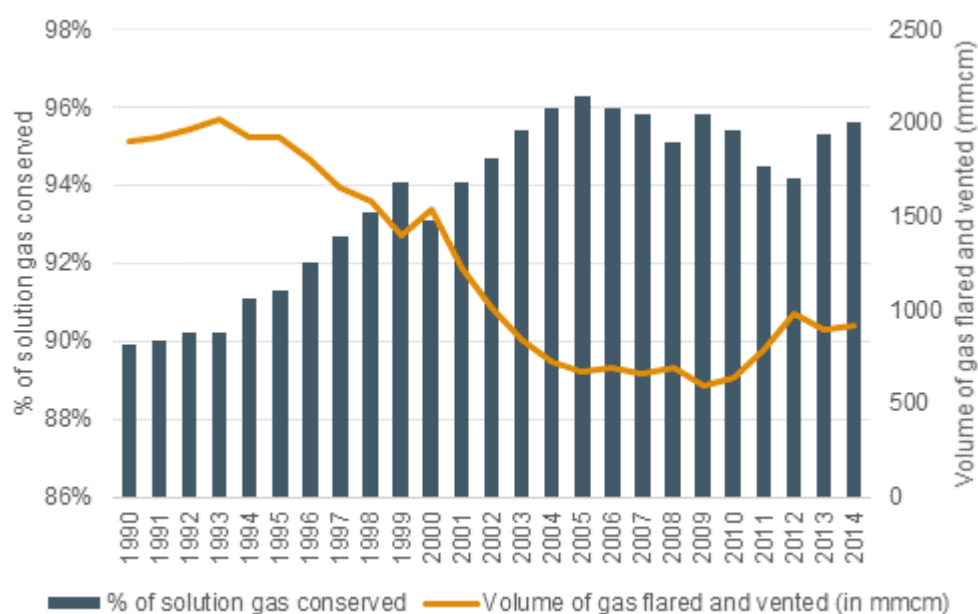
³⁵ BP, *Statistical Review of World Energy*, June 2016.

³⁶ Instead of associated petroleum gas, the term 'solution gas' is used in Alberta's regulatory documents. To avoid confusion in this document and for consistency, we use APG or 'associated gas' throughout ECA documents.

Sustainable Resource Development) to support research on flaring. Findings reported in 1996 identified toxins associated with incomplete combustion and ultimately lead to the implementation of a stricter regulatory framework with the first edition of *Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Venting* in 1999, the main piece of legislation on gas flaring and venting in Alberta. Working with key stakeholders, the EUB set a target to reduce associated gas flaring levels in 2002 to 50% of their 1996 levels, which has then remained as the target and has been exceeded by the industry in some years.

Since the first edition of *Directive 060* in 1999, associated gas and flared and vented volumes have decreased significantly compared to levels in 1996 as shown in Figure 15 below.

Figure 15 Associated gas conserved, flared and vented in Alberta. 1990-2014



Source: ECA elaboration from Alberta Energy Regulator data.

Since 2008, flaring and venting levels have increased again due to increased oil production. Associated gas conservation shares have relatively decreased due to new developments in heavy oil and bitumen areas and also gas price dynamics (in some years, relatively low gas prices made it more challenging to conserve gas).

In 2014, total associated gas flared and vented reached 919 million cubic meters (32,441 million cubic feet), 49% less than the 1996 flaring baseline.

Regulatory overview

Institutional framework

The Alberta Energy Regulator (AER) is the entity responsible for gas flaring and venting in Alberta³⁷. It is an independent agency which was created through the *Responsible Energy Development Act*, which establishes as its mandate:

³⁷ <http://www.aer.ca/about-aer>

- o To provide for the efficient, safe, orderly and environmentally responsible development of energy resources in Alberta through the Regulator's regulatory activities.
- o In respect of energy resource activities, to regulate (a) the disposition and management of public lands, (b) the protection of the environment, and (c) the conservation and management of water, including the wise allocation and use of water, in accordance with energy resource enactments and, pursuant to this Act and the regulations, in accordance with specified enactments.

Energy regulation in Alberta spans more than 75 years and has evolved over time. In 2013, the AER became a new organization and took charge of the regulatory functions related to energy development previously held by Alberta Environment and Sustainable Resource Development (ESRD).

The AER is just one element of Alberta's Integrated Resource Management System. This system also includes the Government of Alberta, which sets policy; the Alberta Environmental Monitoring, Evaluation and Reporting Agency, in charge of providing data and information; the Aboriginal Consultation Office, devoted to managing First Nations consultations on behalf of the Government of Alberta; and the Policy Management Office, which acts as the main interface between the government and the AER.

Currently, the AER is the single regulator of energy development in the province and regulates some of the world's largest hydrocarbon resources. In addition, AER regulates a pipeline network of 431,000 km, 174,000 operating wells, over 50 in situ and 200 thermal oil sands projects, and 9 oil sands mines and 7 coal producing mines.

The AER has the authority to:

- o Review and make decisions on proposed energy developments.
- o Oversee all aspects of energy resource activities.
- o Inspect energy activities to ensure that all applicable requirements are met.
- o Penalize companies that fail to comply with AER requirements.
- o Hold hearings on proposed energy developments.

The AER is established as a corporation. Its terms of structure, corporate, operational, and governance responsibilities are separated from adjudicative functions (hearings on energy applications). AER is funded entirely by the industry. Its budget is established through a formal process between the Government of Alberta and the AER.

Regulatory framework

The AER *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (*Directive 060*, hereinafter) contains the fundamental requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities. Most of the requirements have been developed in consultation with the Clean Air Strategic Alliance

(CASA)³⁸ to eliminate or reduce the potential and observed impacts of these activities and to ensure that public safety concerns and environmental impacts are addressed before beginning to flare, incinerate, or vent³⁹. This highlights a basic feature of Alberta's regulatory framework: its multi-stakeholder consensus driven approach.

The basic goal of the regulation is to eliminate flaring, incinerating, and venting. To achieve this, an objective hierarchy was established:

1. To eliminate routine flaring, incinerating, and venting of unburned gases.
2. To reduce the volume of flared, incinerated, and vented gases.
3. To improve the efficiency of flare, incinerator, and vent systems.

Directive 060 distinguishes between different sources of flaring and venting: associated gas, well testing, natural gas extraction facilities, natural gas plants and pipelines. As commented in the previous section, associated gas is the main source of gas flaring and venting in Alberta. Accordingly, regulations include more provisions and are stricter regarding this source.

Targets for associated gas flared

Regulations set an overall target regarding associated gas flaring. Associated gas flaring limit is set at 670 million scm (23,651 million scf) per year (50% of the revised 1996 baseline of 1340 million scm/year, or 47,302 million scf/year). If associated gas flaring exceeds the 670 million cm in a given year, the AER will impose reductions that will stipulate maximum associated gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than 670 million scm/year.

Regulation is based on a voluntary approach. The overall target does not state the way reductions have to be achieved or in which locations. Rather, the target is aggregate and based on Alberta's gas flaring volume. This performance based approach allows the industry a high degree of flexibility in choosing how to achieve the target. It may also lead to cost reductions and favour the introduction of new technologies in the production process, increasing efficiency. In the case the target is not met, there are regulatory mechanisms to correct the situation and ensure that the target is achieved.

There is no target for venting, as it is not an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved. If venting

³⁸ The Clean Air Strategic Alliance (CASA) is a multi-stakeholder partnership. It is composed of representatives selected by industry, government and non-government organizations.

<http://casahome.org/>

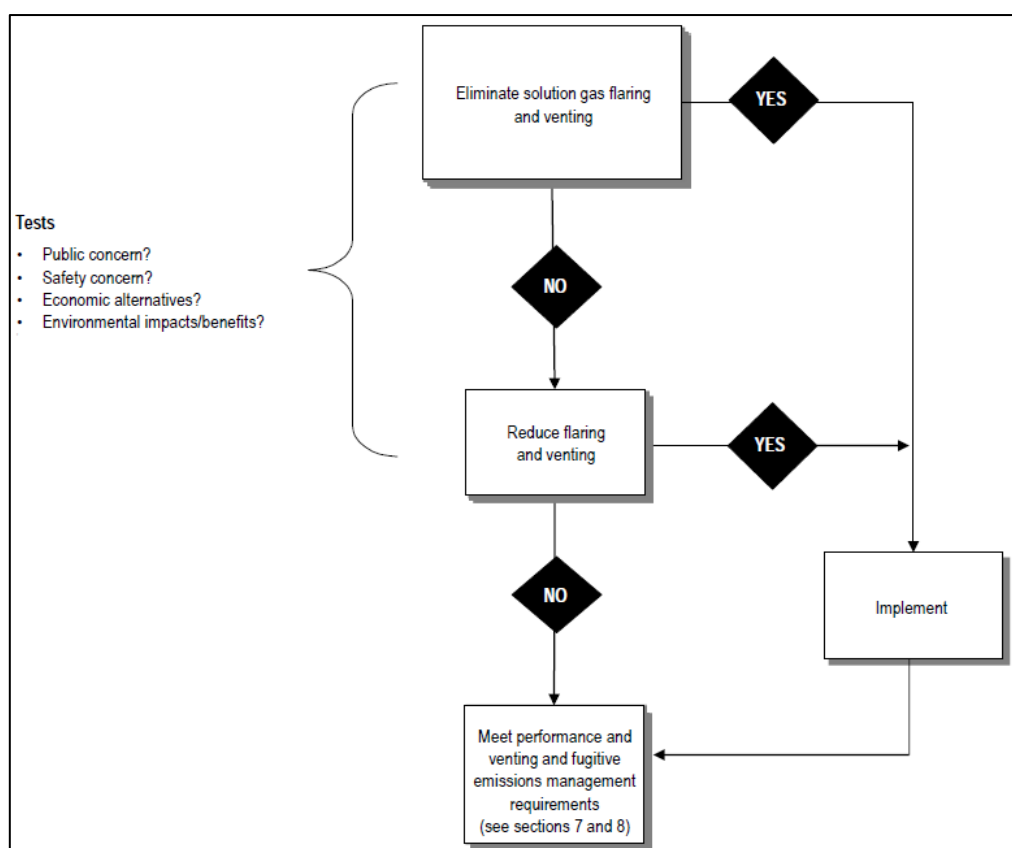
³⁹ CASA has played a role in the development of *Directive 060* since its first edition. Two multi-stakeholder teams from CASA have made recommendations for flaring, incineration, and venting for the upstream petroleum industry, and the AER has based this directive on those recommendations. In particular, the AER has adopted CASA's objective hierarchy and its framework for managing routine solution gas flares and has extended its application of the hierarchy to include flaring, incineration, and venting of gas in general. CASA's recommendations have also been taken into account regarding gas flaring reductions and reduction targets in 2002, 2004, and 2005. Source: *Directive 060*.

is the only feasible alternative, *Directive 060* establishes some requirements under which this alternative must be carried out.

Flaring and venting management framework through decision trees

A fundamental feature of Alberta’s regulation is the establishment of a flaring/venting management framework based on decision trees. This tool requires operators to evaluate options and determine, in a sequential fashion what the best alternative to utilize gas is. The sequence is illustrated in Figure 16.

Figure 16 Associated gas flaring/venting decision tree



Source: *Directive 060*

Operators must apply this decision tree and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented. *Directive 060* envisages different decision trees for different types of gas flaring and venting sources.

In the case of associated gas flaring and venting, licensee or operators must apply the decision tree to all flaring or venting of more than 900 scm (31,770 scf) per day, taking into account economic, social and environmental factors. If conservation (utilization) is determined to be economic by any method using the economic decision tree process, then gas must be conserved. *Directive 060* sets a series of criteria to be used in the economic evaluation.

Conservation of associated gas

Associated gas has to be conserved (utilized) in certain circumstances⁴⁰:

- o If the combined flaring and venting volume is greater than 900 scm (31,770 scf) per day per site and the decision tree process and economic evaluation result in a net present value (NPV) greater than CDN\$ 55,000.
- o When the gas/oil ratio (GOR) is greater than 3,000 m³/m³. In fact, all wells producing with a GOR greater than 3,000 m³/m³ at any time during the life of the well must be shut in until the gas is conserved.
- o If flared volumes are greater than 900 scm (31,770 scf) per day per site and the flare is within 500 m of a residence, notwithstanding what the economic analysis has concluded.
- o If the AER directs the operators to conserve associated gas, regardless of the economic analysis.

Performance requirements

Directive 060 includes a set requirements which must be met by all upstream operators in gas flaring and venting operators must abide to. If after the decision tree process operators conclude that it is not possible to reduce or eliminate flaring and venting volumes, the technical performance requirements are applied to determine whether efficiency improvements can be applied.

Fiscal incentives for associated gas

In 1998, Alberta's Department of Energy introduced the Otherwise Flared Associated Gas Royalty Waiver Program (OFSG)⁴¹. This program provides incentives for gas flaring reduction, since it waives royalty on otherwise flared associated gas and associated by-products when used in a manner that would normally require payment of royalty.

Effectiveness of regulation

Alberta's regulatory framework has had a positive impact in terms of gas flaring and venting reduction⁴². Currently, associated gas flaring and venting levels are 49% less than in 1996. Targets have been exceeded by the industry in many years, which highlights the importance and the relevance of the voluntary approach.

The key feature that seems to have had a positive impact on the success of the regulatory approach in Alberta is active stakeholder participation and good coordination:

⁴⁰ *Directive 060*, Section 2.6.

⁴¹ <http://www.energy.alberta.ca/NaturalGas/1139.asp>

⁴² *Flare and Vent Reduction in Alberta: Approaches that led to Success*, J. Vaughan, Success Gas Flaring Reduction Best Practice Workshop, Ciudad del Carmen, Campeche, Mexico - February 11-12, 2010.

- o Besides passing comprehensive legislation to improve gas utilization, Alberta's Government sought to actively engage with stakeholders, triggering stakeholders to see gas flared and vented as a wasted resource with economic value.
- o The alignment of policy objectives, regulations and regulatory processes ensures that all involved government agencies are working towards the same objectives. Collaboration and coordination between different administrative departments has also helped to coordinate policy activities.
- o A consensus-based approach, which has sought stakeholder involvement to find better solutions and realistic targets which can be met by industry.
- o The decision tree approach, which requires operators to determine whether reducing or eliminating flaring is feasible, and if not, to improve efficiency adjusting to performance requirements.
- o A performance-based and results oriented approach, which allows the industry a higher degree of flexibility in choosing how to achieve the established targets.
- o The combination of a voluntary approach with a regulatory backstop, which provides flexibility to industry but also grants regulatory powers to the AER, providing incentives to achieve the target.
- o Full third party access to upstream and downstream gas pipelines and more competition have impacted on gas flaring reduction.

A1.1.2 Oversight framework

Monitoring processes

Self-reporting

The basic provisions regarding the reporting of volumes of gas flared and vented are included in *Directive 060*, which incorporates both general provisions and specific provisions for different sources of gas. Additionally, we also have to take into account *Directive 017: Measurement Requirements for Oil and Gas Operations*, and *Directive 007: Volumetric and Infrastructure Requirements*.

Measurement provisions are outlined in *Directive 017: Measurement Requirements for Oil and Gas Operations*, according to which measurement of continuous or intermittent flare and vent sources must be undertaken at all oil and gas production and processing facilities where annual average volumes per facility exceed 500 mm³ per day. If the rate is lower than 500 mm³ per day or flaring is infrequent and no measurement equipment is in place, flare volumes must be estimated.

The AER does not specify the types of meters that must be used to meter flare volumes at facilities and sites. As a general rule, it only establishes the single point measurement uncertainty must be $\pm 5.0\%$ and uncertainty of monthly volume must not exceed $\pm 20.0\%$. In

situations where flare gas density can be quite variable, the AER recommends a meter that does not rely on gas density to determine flow rate be used e.g. ultrasonic, vortex, etc. For routine flaring the meter should be sized for the expected flow rate. For non-routine flaring (emergency flaring) a high turndown ratio meter should be used because of the high variability in flow rates.

In terms of general reporting requirements, operators must maintain a log (record) of flaring, incineration, and venting events and respond to public complaints in order to comply with release reporting requirements. Records must be kept for at least 12 months, they must be made available to the AER upon request, and are subject to a series of requirements. First, they must include information on complaints related to flaring, incineration, and venting and how these complaints were investigated and addressed. Second, they must describe each non-routine flaring, incineration, and venting incident and any changes made to prevent future non-routine events from occurring. Third, they must include the date, time, duration, gas source or type, rates, and volumes for each incident.

In additions, regulations establish specific requirements for different sources of gas flared and vented⁴³:

- o **Associated gas**— Associated gas flared, incinerated, and vented must be reported monthly through the Canada’s Petroleum Information Network (PETRINEX)⁴⁴.
- o **Sour gas under temporary permit**— Sour gas flared incinerated (or the lack of it) must be included in a data summary report for each well and submitted to the AER Authorizations Operations Group within 30 days of the end of each calendar quarter-year⁴⁵.
- o **Well test**— a well test report must be submitted within 3 months of completing the field work. The report must include the volume of gas produced to flare or vent. Submissions must be in a pressure ASCII standard (PAS) format and submitted via the well test data capture system in DDS. In addition, gas flared, incinerated or vented due to well activities (including well test) at a well site must be reported monthly through PETRINEX.

⁴³ Directive 060, various sections.

⁴⁴ PETRINEX is an organization supporting Canada’s upstream oil and gas industry. It is represented both by government (Alberta Department of Energy (DOE), the Alberta Energy Regulator (AER) and the Saskatchewan Ministry of the Economy (ECON)) and industry (Canadian Association of Petroleum Producers (CAPP) and the Explorers and Producers Association of Canada (EPAC)). PETRINEX provides services that facilitate fast, standardized, safe and accurate management and exchange of key volumetric, royalty and commercial information associated with the upstream petroleum sector. PETRINEX utilizes a web-based system for its automated business functions and processes. Its web-based interface provides users with on-line access to information. The volumetric data submitted to PETRINEX is subject to system controls and front-end editing procedures before the data is posted within the PETRINEX System. Discrepancies are identified through front-end editing immediately which allows the submitting operator the opportunity to make corrections before the final posting.

⁴⁵ Sour oil and gas well operations such as well servicing may result in flaring of relatively small volumes of gas at several sites in a local area. To simplify temporary permit request requirements, the AER Authorizations Operations Group may issue a single “blanket” permit to cover several flaring events at different sites in an area if so requested by the licensee. Blanket permit are subject to a series of requirements.

- o **Gas Battery, Dehydrator, and Compressor Station**— All monthly flared and vented volumes must be reported separately on PETRINEX in accordance with the general requirements and Directive 007⁴⁶.
- o **Gas Plants**— All monthly flared and vented volumes must be reported separately on PETRINEX. Flaring of sour gas must also be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report⁴⁷. When measurement is not required, engineering estimates must be used to report any flared gas not measured.

Regarding non-routine flaring and venting, in the case a sixth major flaring event occurs in any consecutive rolling six-month period. Licensees must submit a written “exceedance” report to the appropriate AER field centre and copy this report to the AER Authorizations Operations Group within 30 days of the occurrence of the sixth flaring event. The exceedance report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and on their possible causes. The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major non-routine flaring does not recur.

- o **Pipeline**— All monthly flared, incinerated, and vented volumes must be reported separately on PETRINEX.

Since 2010, the AER has put in place the Enhanced Production Audit Program⁴⁸ (EPAP)’s objective is to raise the level of assurance over compliance with the AER measurement and reporting requirements and to raise the level of compliance with these requirements. EPAP has been implemented through *Directive 76: Operator Declaration Regarding Measurement and Reporting Requirements*. Through EPAP, the AER expects to rely less on substantive audits and favour each operator’s controls regarding its compliance with measuring and reporting requirements. A key aspect of EPAP is that each operator must submit a formal Declaration regarding the operating effectiveness of their controls in addressing the risk of noncompliance.

The AER verifies the veracity of the reports on gas flared and vented submitted by the operators through the use of the Enhanced Production Audit Program (EPAP)’s Compliance Assessment approach. Through EPAP, the AER detects anomalies within the volumetric data using algorithms that have been developed in association with rules outlined in directives on measurement requirements. If the AER detects data inconsistencies an operator can be directed to verify whether reported flare or vent volumes are accurate. When non-compliances are identified, remedies may be imposed.

⁴⁶ All licensed compressor stations must have a facility ID, which is created automatically by the Registry upon receipt of a compressor station license from the AER. This facility ID is used to report fuel, flare, and vent volumes at the nearest reporting facility. A compressor station is not a reporting facility, so a monthly facility volumetric submission is not required.

⁴⁷ The S-30 Monthly Gas Processing Plant Sulphur Balance Report below must be submitted to the AER using the electronic Digital Data Submission (DDS) system under “Submit Monthly Sulphur Balance Reporting,” according to the instructions that follow the form.

⁴⁸ <https://www.aer.ca/compliance-and-enforcement/enhance-production-audit-program>

The Alberta Energy Regulator publishes data on gas flared and vented per operator and creates rankings⁴⁹, so information about the operators' performance in terms of gas flaring and gas conservation are public.

Surveillance activities

AER's surveillance activities include field inspections, investigations, audits, and use of the Air Monitoring Units. Audits and investigations are mainly conducted without site inspections while field inspections and the Air Monitoring Units are undertaken on-site. All surveillance activities involve different levels of reviewing required reports, such as production records, or requested information, such as flare and vent logs.

The AER undertakes regular inspections at the development sites to ensure compliance with regulations and a correct disclosure of flaring and venting volumes. The AER has 70 inspectors in 12 locations throughout Alberta. Inspections are undertaken at selected stages of an energy resource activity. Inspections range from singular items, such as flaring or venting, to broad inspections of energy activities.

Types of inspections

There are different types of routine inspections. Scheduled inspections are prioritized and chosen according to a set of different criteria⁵⁰:

- o First, the operator's **compliance history**: inspectors focus relatively more on companies with higher levels of noncompliance or unsatisfactory inspections.
- o Second, the **site sensitivity**, which is assessed by considering factors such as the proximity to bodies of water, its closeness an area where environmental incidents have been relatively frequent, or if it is a forested or agricultural area.
- o Third, the **inherent risk** of the facility or operation, which is grounded in technical details such as well depth or the complexity of the operations.

Schedule inspections are assigned objective numbers for an operational year (for instance, the AER set an objective to conduct 20 well test inspections in 2013-2014)⁵¹.

The AER also carries out non-scheduled inspections, unannounced inspections based on reports or complaints from the public, and inspections to ensure that procedures and equipment are in use to minimize environmental impacts. Unscheduled inspections are in most cases motivated by incidents, such as: product releases, public complaints odour complaints (sour gas, sulphur dioxide, hydrocarbon odours), excessive flaring, black smoke, fires, and lack of public notification.

⁴⁹ For example, see the *Upstream Petroleum Industry. Flaring and Venting Report*, the Alberta Energy Regulator, 2016. <https://www.aer.ca/documents/sts/ST60B-2015.pdf>

⁵⁰ Inspections and Enforcement of Energy Developments in Alberta: https://www.aer.ca/documents/enerfaqs/AER_EnerFAQs03_InspectionsEnforcement.pdf

⁵¹ Information obtained through an information request sent to the Alberta Energy Regulator.

There are no regulatory differences in how scheduled and unscheduled inspections are undertaken as both involve assessing for compliance against AER regulations, rules, and directives. The main difference is logistic. Scheduled inspections can be planned and prepared throughout the year while unscheduled inspections may happen at any time. Scheduled activities can involve requesting information or having meetings prior to site visits.

Typical processes followed during an inspection

Inspectors have the power to enter a site and undertake different types of functions. They have the authority to impose remedies, such as shutting in a well or shutting down a facility, or to issue a stop order requiring the partial or total halting of an activity or land use.

Prior to a site inspection AER staff conducts a records review and a safety hazard assessment⁵². Records reviews may involve the elaboration of reports, previous inspections, overall compliance history, incident history, and AER notifications. Site inspection is focused on assessing the design, operation and maintenance of the flaring and venting equipment. Additionally, it may involve a documentation review and questions to the operator.

Inspection results are entered into the Field Inspection System (FIS). If there are outstanding items (such as information requests, enforcement concerns) these are dealt in a post-inspection stage.

Equipment and software used during inspections

The AER employs different technical tools and equipment when carrying out inspections. Technical tools and equipment include: personal protective equipment, including personal gas monitors; Directive 060; range finders; FLIR cameras; VRAE multi-gas monitors; mobile Air Monitoring Units for sour gas and sulphur dioxide monitoring; portable methane detectors; VOC monitors; and portable infrared spectrometer. All this equipment is not used during a typical inspection, but it is employed by specific personnel (such as Air Monitoring Technicians). The AER also conducts air emissions testing (e.g., source sampling and data verification from gas plant incinerator stacks).

Software used during an inspection includes: Inspection software (FIS); Compliance and Operations Management System (COM, internal AER software containing company, licensing, production, operational data, and compliance information); PETRINEX, Integrated Application Registry (IAR, software which contains licensing and application information including schematics, public notification information, and waivers), and AER flare and incineration dispersion modelling spreadsheets.

The duration of an inspection is usually dependent on each case characteristics such as the records review, site complexity, and location of the activity. An estimate provided by the AER ranges between 1–4 hours for a site inspection and basic records review.

⁵² Information obtained through an information request sent to the Alberta Energy Regulator.

Remedies after the inspection

If the inspection is not satisfactory, the consequences vary on the degree of seriousness of the problem identified⁵³. Inspectors may give time to correct the situation. However, if the situation is deemed dangerous to people or the environment, inspectors have the authority to shut down the facility or to stop the facility until the situation is corrected.

If the problems identified in the inspection persist, the AER will apply its enforcement mechanisms such as administrative penalties, prosecution, enforcement orders, and the shutting down. As explained in a further section, the use of these tools depends on the noncompliance identified.

Audits

In addition to inspections, the AER also conducts audits that consist of a detailed examination of an operator's compliance with AER requirements.

The AER conducts Detailed Operations Inspections⁵⁴ that - together with a site inspection - focus on reviewing information related to flaring and venting: (i) process flow diagram/metering schematic; identification of flare and vent meters/measurement points (including fuel, dilution, purge, and acid gas measurement and performance issues); (ii) submission of production records cross-referenced with flare/vent logs; review of sulphur balance reports; review of metering differences; (iii) integrity of equipment; site approvals; (iv) dispersion modelling; and (v) operating procedures (normal operations, non-routine flaring events, associated gas reduction schedules, and equipment outages).

The AER also conducts Flaring, Incinerating and Venting Audits, namely economic evaluation audits for associated gas conservation.

Enforcement mechanisms

Alberta's enforcement mechanism is set out in *Directive 019: Compliance Assurance*. The key feature of the AER's enforcement system is that it is based on a risk assessment of each regulatory requirement. The AER uses a Risk Assessment Matrix to predetermine the level of risk inherent in noncompliance of each AER requirement. The associated risk of each requirement is based on health and safety, environmental impact, resources conservation, and stakeholder confidence in the regulatory process. If the assessment result on all of the above areas is minimal, noncompliance is considered low risk. If the effect on these areas is more significant, the noncompliant event is considered high risk.

The AER follows a very detailed methodology in order to deal with low and high risk noncompliant events:

- o The processes for low and high risk events have prevention notice tools and enforcement action tools, address noncompliant events and are designed to achieve compliance.

⁵³ <http://www.aer.ca/compliance-and-enforcement/inspections-and-audits>

⁵⁴ Information obtained through an information request sent to the Alberta Energy Regulator.

- o The low risk process is sequential. The first step is the issuance of a Notice of Low Risk Noncompliance. If the noncompliant event continues after the timeframe required by the AER to come into compliance, the AER will issue a Low Risk Enforcement Action.
- o The high risk process is not necessarily sequential. AER's response to a high risk noncompliant event depends on the specific circumstances of the case and the operator's compliance history. For this reason, the AER's response in the high risk process may lead to any of the following actions: (i) Notice of High Risk Noncompliance, (ii) High Risk Enforcement Action, (iii) High Risk Enforcement Action (Persistent Noncompliance), (iv) High Risk Enforcement Action (Failure to Comply), or (v) High Risk Enforcement Action (Demonstrated Disregard).

If the AER determines that there has been non-compliance, the operator will be notified in writing. The AER will set out its response and the timelines by which the licensee is expected to bring itself into compliance. If noncompliance is detected the licensee must correct or address the noncompliance in accordance with the *Directive 019* risk rating. High Risk non-compliances must be corrected or addressed immediately and may involve full or partial suspension of operations. High Risk non-compliances also involve submission of an action plan that identifies the origin of the event and the steps which have to be taken to prevent future occurrences. Low Risk noncompliance items are generally addressed within 30 days.

The approval of the Responsible Energy Development Act the AER has increased the range of enforcement tools. These tools include administrative penalties (a monetary fine) and prosecution.

Typical inspection items in gas flaring and venting and other domains have been risk rated (High Risk or Low Risk). These inspection items/noncompliance statements are included in the AER Table of Noncompliant Events and Associated Risk Rating of AER Requirements⁵⁵.

Commonly detected non-compliances related to flaring and venting include: failing to meter or report gas volumes; venting instead of flaring; black smoke from flares; inadequate flare and vent logs; off-lease odours; and flare knockout design. Actions taken by AER inspectors are to notify the operator/licensee, record the matter in FIS, and follow-up with the operator to ensure compliance. Actions taken by the operator would include: installing meters; establishing the process to report volumes to PETRINEX; directing gas to flare instead of venting; increasing fuel gas to flare; installing more appropriate liquids separation equipment; ensuring accurate information is documented in the future; ensuring equipment and procedures are in place to prevent sour odours; and installing alarms or shutdowns on flare knockouts.

An interesting feature of the compliance assurance program is the Voluntary Self-Disclosure policy, which aims to encourage operators to identify, report, and correct noncompliance. When an operator identifies a noncompliance, the AER expects it to be corrected or addressed and reported to the AER. The AER also expects that operators will behave in the same way as the AER would in case of non-compliance.

⁵⁵ <http://www.aer.ca/documents/enforcement/RiskAssessedNoncompliances.pdf>

Voluntary Self Disclosure has some benefits, such as proactive correction of the noncompliance, savings in terms of enforcement actions, or improved relationships between licensees and the AER. Some requirements and rules govern the voluntary self-disclosure scheme⁵⁶.

Any board orders resulting from non-compliance area made public and posted by the AER in its webpage. In addition, within 120 calendar days of their issuance, the AER publishes all enforcement actions taken by it during the previous period⁵⁷.

A1.1.3 The regulator's role and capabilities

Interface between stakeholders

The AER has a Stakeholder and Government Relations Division (SGR)⁵⁸ devoted to understanding and addressing stakeholders' concerns. Its mandate is to help stakeholders understand the implications derived from the transition to a single regulator, to build and sustain sound working relationships with stakeholders, and to ensure that they understand how best to interact with the AER.

Regulatory development has traditionally been transparent and sought a collaborative approach. In fact, the AER has a standard procedure that requires stakeholder engagement before a regulatory requirement is passed. When a regulatory requirement is proposed, stakeholders have the opportunity to provide feedback. However, in rare cases, regulatory change is proposed by stakeholders.

CASA⁵⁹ has played a role in the development of Alberta's fundamental piece of legislation on gas flaring and venting - Directive 060 - since its first edition. In particular, the Albertan regulator has adopted CASA's objective hierarchy and its framework for managing routine associated gas flares. CASA's recommendations have also been taken into account regarding gas flaring reductions and reduction targets in 2002, 2004, and 2005. Although collaboration with CASA has been intense over the years, since 2008 the AER has been leading regulatory change using collaborative approaches independent of CASA.

⁵⁶ To self-disclose a noncompliance, an operator must (i) be the first party to contact the AER regarding the noncompliance, and (ii) take appropriate steps to correct or address it. When self-disclosing a high risk noncompliance, a licensee must (i) immediately correct or address the noncompliance, including suspending operations if warranted, to ensure that risk to the public or environment is mitigated, and develop and implement a written action plan within 60 days of the high risk noncompliant event or in the time specified by the appropriate AER group. When self-disclosing a high risk noncompliance, a licensee may also be required to submit a written action plan in the time specified by the AER group, and/or meet with the AER group to discuss the high risk noncompliance or the licensee's compliance history.

⁵⁷ Except for a low risk enforcement action where no Refer status has been applied to a licensee and/or no Board Order has been issued in connection with the matter.

⁵⁸ http://www.aer.ca/documents/about-us/AER_Brochure.pdf

⁵⁹ The Clean Air Strategic Alliance (CASA) was established in March 1994 as a new way to manage air quality in Alberta. CASA is a multi-stakeholder partnership. It is composed of representatives selected by industry, government and non-government organizations. Every partner is committed to a comprehensive air quality management system for Alberta.

In addition, the AER engages in communication with the general public, non-government agencies (such as the Pembina Institute) and industry (such as the Canadian Association of Petroleum Producers (CAPP)). The AER also utilizes the Canadian Standards Association (CSA) to write standards thereby enhancing regulatory requirements. The AER also utilizes the Petroleum Technology Alliance Canada (PTAC) to conduct research for emerging issues such as technological advancements. In terms of oversight mechanisms, different stakeholders and entities contribute by providing funding for research and resources or expertise to develop regulation. However, the AER manages oversight mechanisms independently.

The regulator's capabilities

Until January 2014, the AER had a flaring and venting team that dealt with all aspects of flaring and venting from authorizations, to regulatory development and compliance. The number of people on the flaring and venting team was 6. They reported to a wider 'Section' called Production Operations. Production Operations focused on the area of surface production infrastructure from the well head to pipeline. Production Operations was a part of Technical Operations which was also comprised of Well Operations and Pipeline Operations. Technical Operations was a part of the Field Surveillance and Operations Branch (FSOB). FSOB included all of the AER regional field centres and inspectors. The head of FSOB would report to the Chief Operating Officer who would report to the Chairman.

Since January 2014, there has been an organizational change whereby work is structured by type rather than subject. People that were part of the flaring and venting team have been distributed in the compliance, regulatory development or authorizations branches. They still work closely, but not on the same team. Currently the AER has 12 people with flaring/venting/emissions functions. The AER has approximately 1,000 employees.

Requirements in terms of qualifications, skills, and experience for the human resources involved in undertaking monitoring and/or enforcing functions in the area of gas flaring and venting vary depending on the work. For the experienced technical specialists, the expectation may be a professional engineer or geologist with a background in oil and gas operations. For the compliance side, there may be a background in law or law enforcement.

A1.1.4 Lessons learned for Egypt

Overall, Alberta's regulatory framework has contributed significantly to reducing gas flaring levels in the province. The key factors contributing to successful regulations, which are of direct relevance for Egypt include:

- o **High level government commitment:** by passing the necessary legislation, giving the regulator the required powers of enforcement and being closely involved in the policy and regulatory process, the provincial Government has been instrumental in reducing gas flaring and venting volumes.
- o **Aligning policy objectives:** the alignment of policy objectives, regulations and regulatory processes ensures that all involved government agencies are working towards the same objectives. Frequent interactions between AER, Alberta Environment and NEB also help to coordinate policy activities.

- o **Consultative approach of regulation:** the general approach taken is for AER to set targets for reducing flaring in consultation with industry and other key stakeholders. This allows industry participants to determine how best to achieve these targets, within a framework established by AER and with mandatory requirements to associated gas utilisation where this is economic and continued assessment by operators of these opportunities. This ensures realistically achievable targets are set that are supported by the industry and all involved stakeholders.
- o **Strong enforcement powers:** AER and its inspectors are backed up by strong powers. In particular, they have the authority to impose remedies, such as shutting down a facility. These types of remedies have a clear deterrent effect on operators, reducing their incentives to flare more gas than allowed. Moreover, non-monetary remedies, such as interrupting production, can lead to better deterrence results than fines. Fines are sometimes perceived by companies just as a cost of doing business.
- o **Targeted approach:** AER monitors and enforces the framework through a targeted approach, in order to make the most efficient use of its resources. Wells are classified by risk and operators by previous compliance records to identify those where monitoring is most required. Penalties are linked to past compliance providing further incentives for operators to develop good compliance records. Penalties are carefully graduated so that any lack of compliance receives a penalty appropriate to its severity.
- o **Stakeholder engagement:** the close involvement of industry representatives as well as other stakeholder such as resident groups, environmental organisations and other non-governmental associations through the government funded CASA platform has ensured that a continuous dialogue between the key stakeholders and government agencies exist. Cooperation has provided better access to information on what is achievable and created better incentives on stakeholders to deliver.
- o **Decision tree provides clarity to operators:** operators are helped in making their flaring and/or venting reduction investment decision in line with the overall policy and regulatory objectives by applying a decision tree approach which starts by asking operators to assess whether flaring can be eliminated, then whether it can be reduced and lastly allowing it subject to minimum technical requirements. Consistent with the aim of working with industry to implement efficient solutions, the assessment of options looks at the economics of these and options meeting a pre-defined NPV must be implemented.
- o **Focus on economics:** A great advantage of the regulatory mechanism is its focus to reduce flaring in the most cost-efficient way possible across the industry as a whole, rather than imposing solutions or setting targets for individual fields irrespective of their circumstances. Operators are given the flexibility to decide how they can best achieve these targets. The regulations are therefore based on a performance based approach rather than a prescriptive approach.
- o Other factors that have impacted on gas flaring reduction include full third party access to upstream and downstream gas pipelines. The right of every operator to

access gas trunklines and existing and new infrastructure (e.g. in-field pipelines, gas processing plants) with spare capacity at monitored commercially set prices facilitated the marketability of utilised gas. The liberalisation of electricity markets also incentivised operators to utilise gas, as its high dependency on gas (39% of installed capacity) ensured security of gas demand and commercially viable prices.

In terms of oversight framework, the key lessons are the following:

- o Reporting is based on monthly detailed reports submitted by operators through a web-based tool that facilitates reporting and provides information in an organized and consistent manner. Having a rich, well organized and consistent dataset allows for tracking flaring through time, assessing how facilities are performing, knowing where to focus efforts for reduction, and identifying possible anomalies in data to check flaring reports.
- o The reporting and monitoring system is strengthened through a program that requires operators to implement controls to prevent or detect, in a timely manner, noncompliance with measurement and reporting requirements. One key element of this system is that it requires operators to declare that they have this system in place and how they are complying with regulation. This contributes to increasing compliance with regulations and improving the effectiveness of monitoring and reporting.
- o Rich and consistent datasets coupled with the compliance program allow the AER to use computational techniques to detect anomalies in volumetric data reported by operators. This provides a powerful verification system and contributes to increasing the accuracy of reports.
- o The surveillance system encompasses several types of activities. There are on site activities such as inspections and air monitoring units and activities conducted without site visits – such as audits and investigations. This broad range of complementary activities creates a comprehensive and consistent system that contributes to oversight effectiveness.
- o Scheduled inspections are prioritized according to a set of criteria: operator’s compliance history, site sensitivity, and inherent risk of the facility or operation. Prioritized inspections lead to focusing on the “most relevant cases” and increase both effectiveness and efficiency of surveillance resources.
- o The enforcement system is based on a risk assessment of each regulatory requirement, which can be deemed low or high risk. The effectiveness of this system lies in several features. First, it is transparent and predictable, as predetermined risk of each non-compliance and the enforcement process that would follow are publicly available. This also reduces uncertainty for operators. Second, it is proportional, as the degree of the penalty varies with risk and also takes into account recurrent non-compliant behaviour. Third, enforcement mechanisms not only rely on fines, but also other means, such as suspending production.

- o Compliance infractions are made public and posted by the AER in its webpage. As with the publicity of the flaring reports, this imposes a reputational cost on operators and incentivizes them to increase compliance with flaring and venting regulations.

A1.2 Country case study 2: Norway

A1.2.1 Overview of sector and regulations

Sector overview

Oil activities in Norway began with the discovery of Ekofisk oil field in 1969, from which production started in June 1971. Several large discoveries were made during the following years. The Norwegian oil resources are located offshore on the Norwegian continental shelf (NCS). The oil sector constitutes Norway's largest industry. In 2013, the oil sector represented more than 21.5% of the country's GDP⁶⁰ and accordingly has a considerable impact on Norway's tax receipts (oil activities accounted for 29% of total state revenues in 2013).

In 2015, Norway was the 14th largest oil producer, the 11th largest oil exporter, and the 8th largest gas producer in the world⁶¹. Oil is mainly transported to export markets by ship, while gas is shipped through the gas pipeline system to the United Kingdom, Germany, Belgium and France. In 2013, crude oil, natural gas, and pipeline services represented slightly less than half of Norway's export value.⁶²

Currently, there are 78 fields producing in the NCS. In 2015, aggregate production from these fields amounted to approximately 1.9 million barrels of oil per day, and about 117.2 billion scm (4,137 billion scf) of gas.

There are currently over 50 oil and gas companies on the NCS. Licenses to explore for and produce oil are usually awarded to a group of pre-qualified oil and gas companies through licensing rounds. State participation in these joint ventures is undertaken both directly and indirectly. Direct ownership is established through the so-called system of state's direct financial interest (SDFI), where the state-owned Petoro AS⁶³ manages the ownership interests. The state participates in the joint ventures on similar terms as private parties; it covers its share of investments and costs, and receives a corresponding share of produced petroleum. The state owns 67% of Statoil ASA,⁶⁴ which is the largest operator on the NCS.

Gas flaring in Norway takes place on the NCS during well-testing, plant commissioning, production, and during routine and non-routine blow-down of facilities and pipelines, for health, safety, and environmental reasons.

Norway's efforts to eliminate the wasting of associated gas began with the first discoveries of oil in the late 1960s. At that time, there was no network of pipelines on the shelf to transport the gas. Nevertheless, the Norwegian authorities introduced a ban on flaring, with

⁶⁰ *Facts 2014. The Norwegian Petroleum Sector*. Norwegian Petroleum Directorate (NPD).

⁶¹ BP Statistical Review 2016, Energy Information Agency.

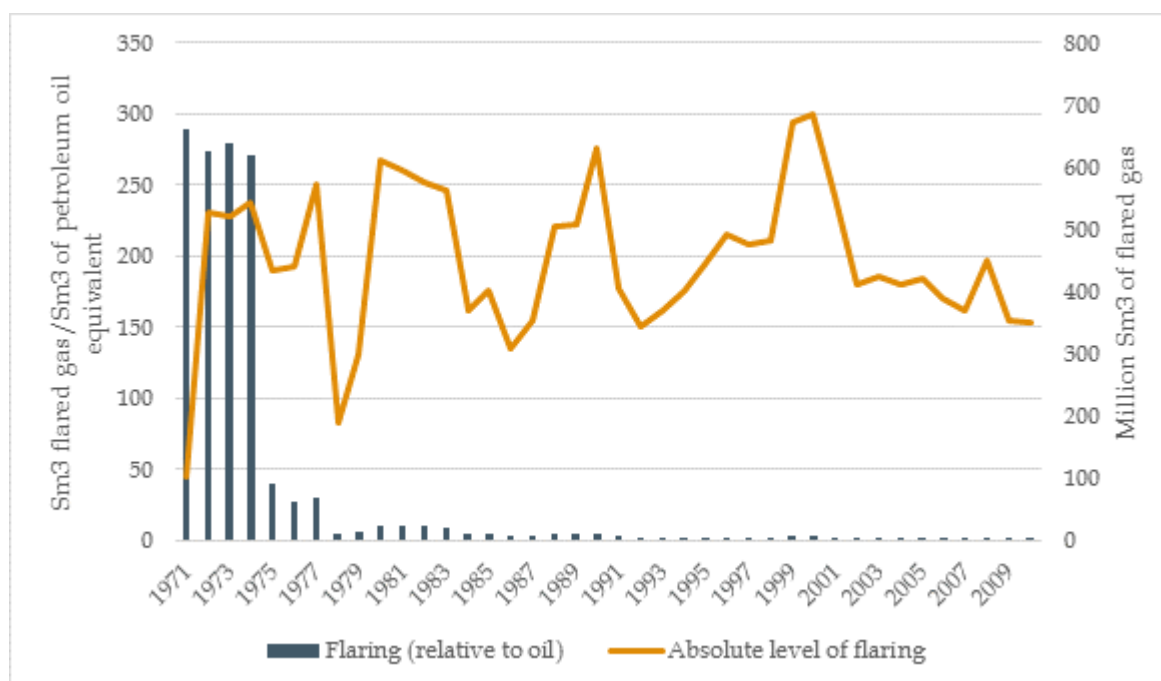
⁶² *Facts 2014. The Norwegian Petroleum Sector*. Norwegian Petroleum Directorate (NPD).

⁶³ Petoro AS is a state-owned company which handles the State's direct financial interest (SDFI), on behalf of the Norwegian State.

⁶⁴ Statoil ASA is an international company with activities in 35 countries. The company is listed on the Oslo and New York Stock Exchange. According to the 2015 Annual Report, the Norwegian State owned 67% of the company's shares.

the exception of what is necessary to ensure the safety of the facilities. As a consequence, oil companies were not allowed to sell the oil until they found a solution for the gas – either by using it for pressure support or by arranging for pipeline transport to customers. The historical relative and absolute volumes of gas flared are shown in Figure 17 below.

Figure 17 Gas flaring on the NCS



Source: ECA from NPD data.

The first major policy change in this domain came in the early 90s. Norway's Government's introduced a tax on CO₂ emissions in 1990s. As a result, both absolute and relative gas flaring levels considerably decreased and currently they are just one-third of the global average⁶⁵. Absolute levels of flaring have fluctuated through time due to increases in oil production (which tend to increase flaring) and the development of the gas pipeline network (which allow for increased gas utilization and reduction in absolute flaring volumes).

Regulatory overview

In the context of oil and gas regulation, there are two Ministries which have key responsibilities in proposing and implementing policy. First, the **Ministry of Petroleum and Energy** (MPE), which has overall responsibility for managing the petroleum sources of the NCS. Its main duty is to ensure that the petroleum activities are carried out in accordance with the guidelines set by the Parliament and the Norwegian Government. The MPE has ownership of state-owned companies Petoro AS, Gassco AS⁶⁶, and has partial participation in the oil company Statoil ASA. Secondly, the **Ministry of Environment** (MOE), which is

⁶⁵ Significant gas resources go up in smoke, Norwegian Petroleum Directorate.

<http://www.npd.no/en/Topics/Environment/Temaartikler/Significant-gas-resources-go-up-in-smoke/>

⁶⁶ Gassco AS is responsible for gas transport from the NCS. The company is the operator of Gassled, although it has no ownership interest in Gassled.

responsible for managing environmental protection and the external environment in Norway.

In terms of developing and shaping policy, the responsibility is shared between the MPE, the MOE and the Standing Committee on Energy and Environment. Enforcement responsibilities are shared between the Norwegian Petroleum Directorate (NPD), the Norwegian Environment Agency (NEA), and the Ministry of Finance (for fiscal measures aimed at flaring).

The **Norwegian Petroleum Directorate** (NPD) constitutes the key institution in terms of flaring regulation policy and enforcement⁶⁷. The NPD was established in 1972 as a governmental directorate and administrative body which reports to the MPE.

Its fundamental objective is to contribute to maximize value from the oil and gas activities for society, through resource management based on safety, emergency preparedness and safeguarding the external environment. It has four main functions: to advise the MPE, to take responsibility for data from the NCS, to work towards realizing the resource potential, and in cooperation with other authorities, to ensure comprehensive follow-up of the petroleum activities.

In addition, the NPD has other duties, such as:

- o Setting frameworks, stipulating regulations and making decisions in its areas of authority
- o Conducting metering audits and collecting fees from the petroleum industry.
- o Ensuring the security of supplies (together with the MPE).

The **Norwegian Environment Agency**⁶⁸ (NEA) has responsibility for following up the *Pollution Control Act*. Another key task is to provide advice and basic technical materials to the MOE.

The Norwegian regulatory system is based on close cooperation between the different institutions. Most of the cooperation focuses on the relationship between the NPD and the other agencies and Ministries, given its fundamental role in management and regulation of the offshore industry.

Gas flaring and venting policies have existed in Norway since the beginning of oil production activities. The original motivation behind these regulations was to avoid wasting of valuable energy, while the pollution aspect of flaring and venting was introduced later⁶⁹. Norwegian environmental policy combines direct regulation and economic instruments, such as tax mechanisms and market based instruments.

⁶⁷ <http://www.npd.no/en/About-us/>

⁶⁸ Established on 1 July 2013 as a result of the merger between the Norwegian Climate and Pollution Agency and the Norwegian Directorate for Nature Management.
<http://www.miljodirektoratet.no/no/Om-Miljodirektoratet/Norwegian-Environment-Agency/>

⁶⁹ *Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience*, World Bank.

Flaring and venting regulation is based on a key governmental commitment under the *10 Oil Commandments*, produced by the Standing Committee on Industry of the Norwegian Parliament in 1971. Commandment number 5 states that “*flaring of exploitable gas on the NCS must not be accepted except during brief periods of testing*”. The initial objective of this commandment was related to avoiding wastage rather than to reduce the environmental impact of flaring.

Policy measures to control flaring are articulated through a combination of different instruments:

- o **Gas flaring specific regulations** regarding permits for field developments and flaring permits, mainly through the Petroleum Activities Act.
- o Implementation of a **CO₂ Tax** on offshore emissions, including flares.
- o Emissions of **greenhouse gas trading scheme**.

We discuss each of these in more detail in the subsections below. In summary, Norway’s overall approach to gas flaring combines regulatory controls on field developments, tax mechanisms, the ETS regulation of operational activities, and the performance based approach. All these elements have created a sound system of incentives for operators to minimize flaring on the NCS, leading to two key technical developments on the NCS: (i) gas reinjection, which is routinely applied to stranded gas in order to avoid flaring and associated penalties; and (ii) development of flare gas recovery technologies.

Gas flaring specific regulation

The two main pieces of legislation specific to gas flaring and venting are the:

- o Petroleum Activities Act⁷⁰
- o Pollution Control Act⁷¹

In addition to above there are also the Regulations to Act relating to petroleum activities⁷² and the Guidelines for applying for production permits.

Under the *Petroleum Activities Act*, there exists a prudent extraction principle⁷³. First, oil production has to take place in such a manner that as much as possible of oil in place is produced. Second, oil production has to take place in accordance with prudent technical and sound economic principles and avoiding waste of oil or reservoir energy. Third, operators must constantly evaluate their production strategy and their technical solutions, taking all the necessary measures to achieve this end.

⁷⁰ Act 29 November 1996 No. 72 relating to petroleum activities, last amended by Act 24 June 2011 No 38.

⁷¹ Act of 13 March 1981 No.6 Concerning Protection Against Pollution and Concerning Waste.

⁷² Laid down by Royal Decree 27 June 1997 pursuant to Act 29 November 1996 no 72 relating to petroleum activities, section 10-18 and Act 10 February 1967 relating to procedure in cases concerning the public administration, section 13 c third paragraph and section 19 third paragraph. Last amended by Royal Decree 2 July 2012 No 729.

⁷³ *Petroleum Activities Act*, section 4-1.

Operators are allowed to lift, process, and use associated gas in operations, re-inject it, or flare it, subject to relevant consents and approval of a field development plan⁷⁴. Burning oil in excess of the quantities needed for normal operational safety is not allowed, unless it has been approved by the MPE⁷⁵. There are no specific gas flaring targets, but permission to flare gas is restricted.

Flaring and venting are subject to production permits⁷⁶. Regulations set out an application process for liquid and flaring/cold venting permits. Applications must indicate expected volumes of petroleum to be produced, flared and cold vented. The expected monthly volume must be indicated for the production volume. The flaring and cold venting volume must be indicated as average million Sm³ per day per quarter. The permit applies to the coming calendar year.

Permit applications must include information regarding the type and level of atmospheric emissions and the technology which will be applied to avoid or reduce pollution. Emission limits are established on a case-by-case basis, taking into account the relevant and applicable national and regional standards⁷⁷.

Applications must be sent to the MPE with a copy to the NPD. In the event of an assumed production over-run for liquid of 10% or more, a new application must be submitted to the Ministry as soon as possible. If the production development throughout the period shows that the production volumes will be reduced by 10% or more in relation to the applied for volume, this must be reported to the MEP and the NPD as soon as possible. If cold venting or flaring deviate from the framework stipulated in the MPE permit, a new application must be submitted to the Ministry as soon as possible.

The development and production of oil fields involves continuous emissions to the air. Several policy instruments are deployed by the authorities to limit the environmental impact of flaring during the operating phase. Amongst others, these include conditions attached to plans for field development and operation. Before the field development plan will be approved, operators need to have a solution for using associated gas. Operators willing to develop a petroleum deposit must submit to the MPE for approval a plan for development and operation of the petroleum deposit (PDO)⁷⁸, including, amongst other information, an account of economic aspects, resource, technical, safety related, commercial and environmental aspects. The plan shall also comprise information on facilities for transportation or utilization. In addition, in certain cases, operators may need to present a plan for installation and operation of facilities for transport and utilization of petroleum (PIO)⁷⁹.

The PDO must include an environmental impact assessment (EIA) requirements and describe all sources of emissions to air and best available techniques adopted to mitigate such emissions. Operators must also describe how they intend to use or re-inject associated

⁷⁴ *Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience*, World Bank.

⁷⁵ *Petroleum Activities Act*, section 4-4.

⁷⁶ *Guidelines for applying for production permits*, Revised 31 October 2011.

⁷⁷ *Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience*, World Bank

⁷⁸ *Petroleum Activities Act*, section 4-2.

⁷⁹ *Petroleum Activities Act*, section 4-3.

gas so as to avoid continuous flaring, as well as the equipment and process they will use for that end.

The *Pollution Control Act* outlines the requirements for permits for discharges to various media. NPD and MPE enforce these requirements through the PDO and EIA components of field development approval and the flare permitting processes.

In summary, Norway's regulation does not impose prescriptive standards for the design of flare systems. Rather, it favours a performance-based approach. Developers must specify their technical design approaches to associated gas management in their plans (including the PIO and PDO), which are subject approval by the NPD and MPE pursuant to their respective mandates.

CO₂ Tax on offshore emissions

Norwegian regulation includes fiscal measures that discourage flaring. Under the CO₂ Discharge Tax Act⁸⁰, which took effect on January 1991, a CO₂ tax is applied to emissions from the burning of all hydrocarbons and also any vented emissions (CO₂) from offshore operations. In line with Report No. 21 to the Storting (2011-2012) Norwegian climate policy, the CO₂ tax for the petroleum activities has increased by NOK 200 per tonne CO₂ effective January 2013. The fee is NOK 0.96 per Sm³ of gas and litre of oil or condensate.

Greenhouse gas trading scheme

Norway also participates in the European Union's greenhouse gas trading system (EU ETS) that commenced operation in 2005. The trading scheme includes all emissions from burning of petroleum offshore, including gas flares. The *Greenhouse Gas Emission Trading Act* was enacted in 2004⁸¹ and was most recently amended in April of 2011. The third emissions trading period started on 1 January 2013, and will run until 2020.

Effectiveness of regulation

Since production started on the NCS in 1971, over 2,000 billion cm (70,600 billion scf) of gas has been produced. Most of it has been exported to European markets, while approximately 25% has been injected into the reservoirs to contribute to improved oil recovery. A small amount has been consumed in Norway in the petrochemical sector, and a very low level has been flared⁸².

⁸⁰ CO₂ Discharge Tax Act. Act 21 December 1990 no 72 relating to tax on discharge of CO₂ in the petroleum activities on the continental shelf. Last amended by Act 20 December 1996, no 100.

⁸¹ Norway Greenhouse Gas Emission Trading Act. Act of 17 December 2004 No. 99 Relating to Greenhouse Gas Emission Allowance Trading and the Duty to Surrender Emission Allowances. The act has been amended since 2004, although amendments after 29 June 2007 are not translated to English. <http://www.regjeringen.no/en/doc/laws/acts/greenhouse-gas-emission-trading-act.html?id=172242>

⁸² "Tough line pays off", Norwegian Petroleum Directorate, <http://www.npd.no/en/Publications/Norwegian-Continental-Shelf/No2-2010/Tough-line-pays-off/>

The Norwegian environmental policy combines direct regulation and economic instruments such as tax mechanisms and market based instruments, which have proved very effective in reducing gas flaring and venting levels. The main regulatory factors which explain success are:

- o The prudent extraction principle and the commitment to the strict principle that flaring of exploitable gas on the NCS must not be accepted except in certain situations and subject to administrative approval.
- o Implementation of strict approvals on field developments based around the development plan system and the existence of strict production permits. Industry is then forced to find ways of exploiting associated gas prior to development. In most cases this means marketing the gas through pipelines, or injecting it if there is no pipeline available.
- o The use of environmentally efficient solutions, such as CO₂ taxes and greenhouse gas emission trading schemes. These schemes complement direct regulation measures and include rigid guidance as to how flare volumes and carbon content are to be monitored and reported. They shape incentives in the right direction for gas utilization maximization.
- o Open access to gas transport infrastructure. Norwegian Authorities have played a key role in creating and expanding transport capacity of gas export, and ensuring third party access and maximization of capacity utilization.
- o Performance based approach, which does not impose prescriptive standards for the design of flare systems and allows operators to propose the ways in which they will manage flaring.
- o Intensive cooperation between the Norwegian authorities and oil companies.

A1.2.2 Oversight framework

Monitoring processes

The different types of policies and regulations that make up the gas flaring framework in Norway (described above) define different and complimentary ways of reporting and monitoring. We discuss each separately below.

Gas flaring specific regulation

According to the Regulations of the Petroleum Act, operators must meter and analyse oil produced, including oil that has been sold⁸³. The equipment and the procedures must be approved by the NPD. Operators must continually monitor the deposit during production, including pressure and flow conditions, produced or injected volumes per well, zone and

⁸³ Regulations of the Petroleum Act Section 26.

reservoir or the composition of components of oil⁸⁴. Operators must establish management systems to ensure compliance with statutory requirements⁸⁵.

The *Regulations relating to resource management in the petroleum activities*⁸⁶ set out reporting requirements for operators. Operators must submit to the NPD monthly flaring volumes per facility/structure together with other production and injection data.

There exist some digital formats used by the NPD to receive the information. The Common Production Exchange (COPEX) format is an ASCII format that has been used for monthly reporting since the year 2000⁸⁷. Recently the NPD has developed a new reporting format, XML-based, the Monthly Production Reporting Markup Language (MPRML). It was first used in 2013 to report production data on the Asgard field.

Additionally, in 2004 the former Norwegian Climate and Pollution Agency (NCPA), the NPD and the Norwegian Oil Industry Association established a joint database, Environmental Web (EW), to report discharges to sea and emissions to air from the petroleum activities. All operators in the NCS must report emission and discharge data for the database.

According to the *Petroleum Activities Act*⁸⁸, the Ministry may carry out regulatory supervision to see that the provisions outlined in the Act are complied with by all who carry out petroleum activities. Representatives from the Ministry, the NPD or other authorities as decided by the NPD, have the right to access the facilities for petroleum activities at any time, as well as to data and materials which are necessary to perform regulatory supervision⁸⁹. They also have the right to take part in exploration activities. Representatives from these authorities may stay on the facilities for as long it is necessary. Operators have to provide transportation services to representatives of the authorities, as well as stay on board services.

NPD undertakes regular inspections to ensure compliance with regulation. Additionally, the NPD undertakes audits for flaring and venting measurement and reporting to determine whether data provided by operators is accurate or not⁹⁰. NPD also supervises environmental measures and activities⁹¹. Information on actual inspections carried out by NPD were unfortunately not made available.

⁸⁴ *Regulations of the Petroleum Act Section 27.*

⁸⁵ *Regulations of the Petroleum Act Section 26.*

⁸⁶ *Regulations relating to resource management in the petroleum activities*, 18 June 2001, NPD.

⁸⁷ "Reporting production data to the Norwegian Petroleum Directorate"

<http://www.npd.no/en/Reporting/Production/Reporting-production-data-to-the-Norwegian-Petroleum-Directorate/>

⁸⁸ *Petroleum Activities Act*, Section 10-3.

⁸⁹ *Regulations of the Petroleum Act Section 81.*

⁹⁰ "The Trend of Gas Flaring and Its Associated Problems in Nigeria: Lessons from a Norwegian Case Study", Aa Arowolo and Ji Adaja, *Journal of Applied Science and the Environment*, Vol. 3, pp 68-79, 2012.

⁹¹ *Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience*, World Bank

CO₂ tax

*Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO₂-Tax*⁹² establish requirements on how the quantities of fuel and flare gas have to be reported and documented, namely regarding measurement⁹³. They also establish standards that include guidance for operators on the protocols and standards they should use in designing their metering systems.

Operators have to comply with these requirements when establishing their measurement systems. Operators have to establish, follow up and assure the development of a management control system including organization, processes, procedures and resources necessary to ensure compliance with the regulations. The allowable measurement uncertainty in the case of gas flaring measurement system is 5% of standard volume. Operators also have the obligation to check sensor calibration every six months⁹⁴. Reporting of fuel and flare gas to the NPD shall be in standard cubic meters in respect of natural gas and litres in respect of diesel or other hydrocarbons in liquid phase. Flare figures for complying with the CO₂ tax have to be reported to the NPD every six months using a standard form.

The NPD supervises compliance with provisions laid down in or decisions made pursuant the regulations. In order to carry out its supervisory activities in the area of fiscal measurement of oil and gas in the NCS⁹⁵, the NPD does not issue certificates or similar documents, mainly because those documents tend to shift the responsibility for the quality of the operations from the operator to the authority, reducing the operators' incentives to seek compliance with regulations. It is the operators' role to establish, follow up and assure a management control system to ensure compliance with regulations.

The NPD employs several supervisory activities to assess proper operation of measurement systems, such as⁹⁶:

- o technical audits/verifications
- o auditing the quality management systems
- o verification of adherence to rules and regulations
- o technical meetings, such as annual meetings and ad hoc meetings on technical matters
- o review of the operator's programme for preventive maintenance.

⁹² *Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO₂-Tax*, 1st November 2001.

⁹³ Reporting of fuel and flare gas to the NPD shall be in standard cubic meters in respect of natural gas and liters in respect of diesel or other hydrocarbons in liquid phase.

⁹⁴ *Regulation of Associated Gas Flaring and Venting. A Global Overview and Lessons from International Experience*, World Bank.

⁹⁵ General information on the Norwegian regulatory regime pertaining to fiscal measurement of oil and gas from the Norwegian continental shelf, Norwegian Petroleum Directorate.

⁹⁶ *General information on the Norwegian regulatory regime pertaining to fiscal measurement of oil and gas from the Norwegian continental shelf*, Norwegian Petroleum Directorate.

Additionally, each year the NPD develops a plan describing the various supervisory activities relating to fiscal measurement of oil and gas. When developing the plan, the NPD takes into account the experience from earlier supervisory activities, or the economic impact of the measurements concerned.

Greenhouse gas trading

The European Union legislation has established common guidelines for monitoring and reporting across installations covered by the scope of the EU ETS scheme⁹⁷. Under the trading scheme guidelines, all types of routine and non-routine flaring must be measured and reported. Data collected by NPD regarding the CO₂ Tax is also used for the purpose of Norwegian ETS compliance in relation to gas flaring.

The monitoring plan plays a central role in the monitoring system established by EU ETS rules. It includes a complete documentation on the methodology of an operator's specific installation⁹⁸. It is the operators' responsibility to design and implement the monitoring plan, which takes into account the nature and functioning each particular installation. Monitoring plans are approved by the competent authority (CA) in each Member State. The CA may carry out inspections at installations, to gather assurance that the monitoring plan is well aligned to the reality of the installation. The CA may, for example, check if the installed meters are of the type laid down in the monitoring plan, whether required data is retained, and written procedures are followed as required.

The other basic element of the EU ETS is the emission report. Installations falling within the scope of the trading scheme must submit to the competent authority by 31 March of each year an emission report that covers the annual emissions of the reporting period and that is verified in accordance with Regulation (EU) No 600/2012⁹⁹. The emission report held by the competent authority shall be made available to the public by that authority subject to national rules¹⁰⁰. Operators are required to use electronic templates or specific file formats for submission of emissions reports¹⁰¹.

The verification of the emission report is carried out by a verifier – an independent third party that verifies the report. The verifier has to provide a verification report that proves the emission report is free from material misstatements and complies with EU regulation. EU regulation establishes that this verification has to be carried by a verifier accredited by a national accreditation body (NAB) or by a natural person verifier certified by a national certification authority (NCA). Most Member States have set up an accreditation system

⁹⁷Commission Regulation (EU) No 601/2012 of 21 June 2012 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council (OJ L 181, 12.7.2012, p. 30) entered into force on 1 August 2012 and applies from 1 January 2013.

⁹⁸ The typical elements of a monitoring plan include: data collection (metering data, invoices, production protocols, etc.); sampling of materials and fuels; laboratory analyses of fuels and materials; maintenance and calibration of meters; description of calculations and formulae to be used; control activities; data archiving (including protection against manipulation); regular identification of improvement possibilities.

⁹⁹ Commission Regulation (EU) No 601/2012, article 67.

¹⁰⁰ Commission Regulation (EU) No 601/2012, article 71.

¹⁰¹ Commission Regulation (EU) No 601/2012, article 74.

whereby the NAB accredits legal entities or legal persons. Each operator must contract a verifier to verify its emission report.

Verifiers main tasks are the following¹⁰²: check whether the operator is complying with the monitoring plan; check whether data are properly stated; detect changes in the monitoring plan which have not been reported to the competent authority; check whether the operator has carried out an uncertainty and risk assessment; carry out site visits; and identify and report outstanding misstatements, non-conformities, non-compliance with the monitoring and reporting regulation and recommendations for improvements.

Enforcement mechanisms

Enforcement mechanisms also differ depending on the policy instrument.

Gas flaring specific regulation

According to the *Petroleum Activities Act* (sections 10-16 and 10-17), authorities may impose fines in cases on non-compliance with regulations. In the event of serious or repeated violations of acts and regulations, stipulated conditions or orders issued, the MPE may impose a temporary suspension of the activities. Information on the actual fines imposed by MPE/DPE were not available.

In certain cases, breaches of the Act may lead to imprisonment for up to 3 months, and if there are aggravating circumstances, imprisonment for up to 2 years may be imposed.

CO₂ tax

Breaches of CO₂ tax regulations may ultimately lead to fines and suspension from trading, according to provisions set up in the Norwegian Criminal Code.

Greenhouse gas trading

Non-compliance with greenhouse gas emission regulations' requirements results in a fine of €100 for each tonne of CO₂ emitted for which allowances have not been surrendered. Continued non-compliance can potentially result in penal measures being taken.

A1.2.3 The regulator's role and capabilities

Interface between stakeholders

Traditionally, Norway's regulation on gas flaring has sought a consensus based approach and fostered the involvement of stakeholders. In 1995, a cooperative body called Miljøso

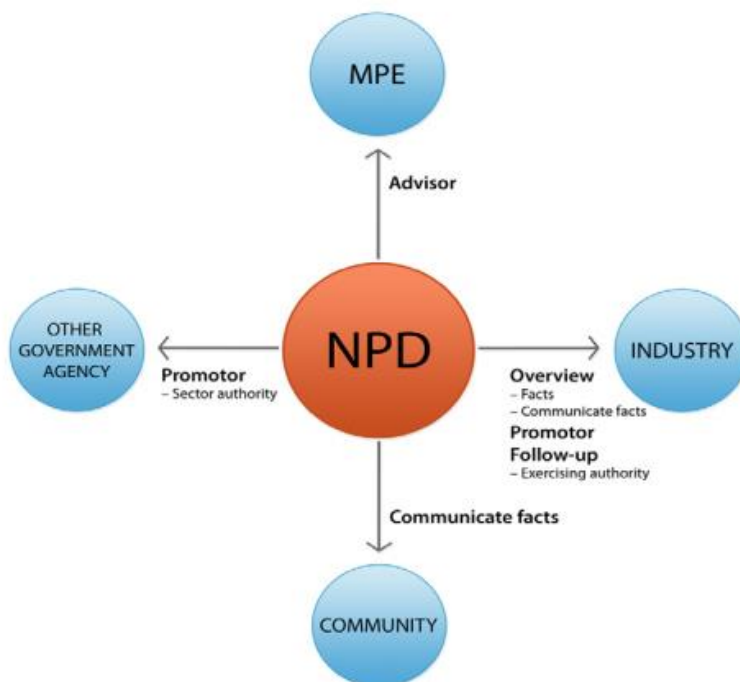
¹⁰² Commission Regulation (EU) No 600/2012 of 21 June 2012 on the verification of greenhouse gas emission reports and ton-kilometer reports and the accreditation of verifiers pursuant to Directive 2003/87.

was established to promote collaboration between the Norwegian authorities and all interested parties in the oil industry. Its basic aim was to promote an environmentally sound oil industry while maintaining its international competitiveness.

The Norwegian Oil Industry Association (NOA) is the key body where collaboration between the public authorities and the main interested parties in Norway’s petroleum industry takes place. The NOA is a professional body and employer’s association for oil and supplier companies engaged in the field of exploration and production of oil and gas on the NCS. It represents the oil and the gas industry on policy related matters including health, safety environment and economic policy towards the petroleum industry.

The civil society is also involved in the consensus based approach of Norway’s legislation. Development plans and environmental impact assessments that operators have to present to the Minister for approval are subject to public review and public hearing in accordance with the *Pollution Control Act*. NPD’s interaction with stakeholders is summarized in the below diagram.

Figure 18 NPD interaction with stakeholders



Source: *The Norwegian Petroleum Directorate – Roles and responsibilities*, Bente Nyland, Norwegian Petroleum Directorate, June 2014.

The regulator’s capabilities

The NPD has around 220 employees¹⁰³. The organizational structure is focused on interdisciplinary teams. The NPD has a very flat hierarchy, with just two organizational levels and only five per cent management positions. Areas of responsibility and teams and employee portfolios are distributed among the managers, and the management has a

¹⁰³ *The Norwegian Petroleum Directorate – Roles and responsibilities*, Bente Nyland, Norwegian Petroleum Directorate, June 2014.

collective responsibility for the organization.¹⁰⁴ The NPD emphasizes cooperation with other agencies and regulatory bodies in Norway and internationally, as well as with research institutes.

A1.2.4 Lessons learned for Egypt

Norway's overall regulation on gas flaring and venting has been very effective due to several factors:

- o Creation of one *independent regulator* responsible for all aspects of environmental regulation. Institutionally, nearly all responsibility for regulatory oversight of operations is led and organised by the NPD. It is required to coordinate with other relevant bodies in relation to, for example, reporting of emissions to air (to the Klif and MOE) and petroleum taxes including the CO₂ tax. It takes a lead on both aspects, with the other agencies relying on information provided by the NPD.
- o *Institutional cooperation* between the NPD and other public sector agencies, and collaboration between the public bodies and the industry.
- o The *combination of regulatory, fiscal and market-based approaches* has been successful in reducing associated gas flaring in Norway. Since the CO₂ tax was introduced in 1990, over the period 1990-2010 flare gas volumes per unit petroleum production decreased to on average 32% of the levels of the previous decade (2.2 scm/scm oe compared to 6.9 scm/scm oe over the period 1980-1990)
- o A *performance based approach to regulation*, which does not impose prescriptive standards for the design of flare systems and allows operators to propose the ways in which they will manage flaring. Crucially, it imposes requirements on developers to come up with gas utilization plans prior to field development.
- o Adequate *development of gas pipeline infrastructure* and access to pipeline, which has favoured gas utilization. While this was focused on gas exports for Norway, for Egypt access to the network and potentially to domestic offtakers, bypassing the single buyer could provide additional incentives.

In terms of oversight framework, the key lessons are the following:

- o The use of different mechanisms to tackle gas flaring and venting (specific regulation, CO₂ tax and the greenhouse emissions trading scheme) has resulted in a comprehensive system of reporting and monitoring that increases the flow of information and allows authorities to detect inconsistencies and increase the effectiveness in reporting and monitoring.
- o Norway benefits from a regulator (NPD) that has been established for a long period of time and is very well resourced.

¹⁰⁴ <http://www.npd.no/en/About-us/Organisation/>

- o Software tools employed in reporting help to gather and organize gas flaring and venting information, which can be used to evaluate the regulation, decide where to focus efforts on or detect anomalies in reporting. The creation of a joint database in cooperation with the industry association allows the public authorities and the companies to track emissions to air over time in a consistent manner.
- o Reporting and monitoring mechanisms shift responsibility to operators, who are forced to establish management and control systems to ensure compliance with regulations and to improve their performance. This type of active compliance mechanism - complemented with adequate oversight - increases the operators' incentives to seek effective compliance, increasing oversight effectiveness.
- o Supervisory activities in the fiscal measurement area are based on an optimization approach, which takes into account experience from earlier supervisory activities and the economic impact of the measurements concerned. These criteria are used to develop an annual plan for supervisory activities. Planned and prioritized supervision increases efficiency and effectiveness of oversight.
- o Authorities are backed up by strong supervisory rights if needed, such as rights to access the facilities, data or materials related to oil activities at any time, to take part in exploration activities, or to stay in the facilities as long as it is necessary. Strong supervisory powers increase deterrence.
- o Enforcement mechanisms not only rely on monetary fines, but also on other means, such as the temporary suspension of the activities. Fines may be seen as a cost of doing business for companies, and therefore, may turn less effective than other types of coercive means.

A1.3 Country case study 3: United Kingdom

A1.3.1 Overview of sector and regulations

Sector overview

The UK is the second largest oil & gas producer in Western Europe after Norway. The UK oil & gas industry is centered on offshore production in the North Sea, with smaller pockets of production in the Irish Sea and some onshore shale oil production. The focus of this review is on the North Sea as this is the main oil producing region (about 98% of production in 2016).¹⁰⁵ Early development of the UK oil & gas industry began in the 1960s and early 1970s, although development was slow, characterized by few commercial discoveries, many dry holes and exploration challenges in the tough environmental conditions of the North Sea. Early efforts over the period were led by several companies, both private and state-owned. However, despite several large discoveries, there was reluctance to develop the area because of uncertainty about overcoming the technical challenges (at water depths >100 meters and difficult weather and sea conditions) and general concerns about the prospects for production in the region.

Since 1975 until today, oil production has fluctuated significantly as a result of the varying economic and political climate across the globe. Figure 19 below shows the evolution of the UK's oil and gas production. Additionally, the figure illustrates the total volume of associated gas and the share of it which was flared. As shown, hydrocarbons production has been falling since its peak in 2000. By 2005, the UK had switched from being a net exporter of crude oil to a net importer, and today production is significantly lower than the peaks of the mid-80s and late-90s. The UK's production levels have fallen from a peak of 2,930 thousand barrels per day in 1999 to 965 thousand barrels per day in 2015.¹⁰⁶

The UK gas industry started on the back of synthetic "town" gas produced from coal. However, in 1964, the first commercial imports of LNG from Algeria commenced to the Canvey Island terminal in Eastern England, and so the UK's transition from town gas to natural gas started. Following this, offshore discoveries of natural gas were made in the late-1960s, marking the beginning of the North Sea natural gas industry. The focus of production was in the large gas fields of the Southern North Sea. In addition, a reasonable volume of associated gas was also gathered from North Sea oil production.¹⁰⁷ UK natural gas production peaked in 2000 at over 3,800 billion cubic feet (Bcf), and has been in fairly steep decline thereafter with current production standing at around 1,300 Bcf in 2013. This has resulted in the UK being increasingly reliant on gas imports from Norway and via its five LNG terminals.

In light of increasing taxes on operators on the UK Continental Shelf (UKCS), and a response by industry to reduce investment in several projects, the UK Government sought to incentivize further investment in the UKCS. The *Wood Review*, after Sir Ian Wood, published

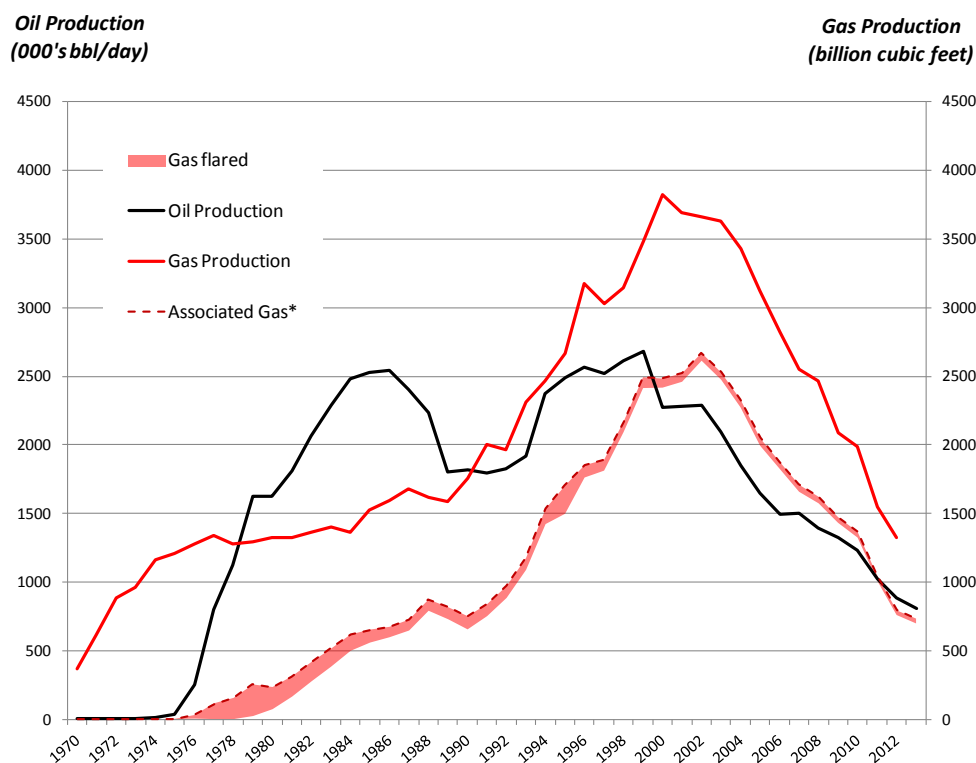
¹⁰⁵ UK Production Data Release, 1 September 2016: <https://www.gov.uk/guidance/oil-and-gas-uk-field-data>

¹⁰⁶ BP Statistical Review of World Energy, 2016.

¹⁰⁷ Although UK DECC published data on North Sea associated gas production, it is unclear whether it represents gas shipped to market, or whether it also includes use on platforms and volumes flared.

its final findings regarding UK offshore oil and gas recovery and its regulation in February 2014,¹⁰⁸ focusing on means to maximize economic recovery.

Figure 19 UK crude oil and natural gas production (1970-2013)



Source: US EIA, BP Statistical Review of World Energy 2016, UK DECC

*Amounts are the total produced as measured at the wellhead, i.e. before any utilization or flaring

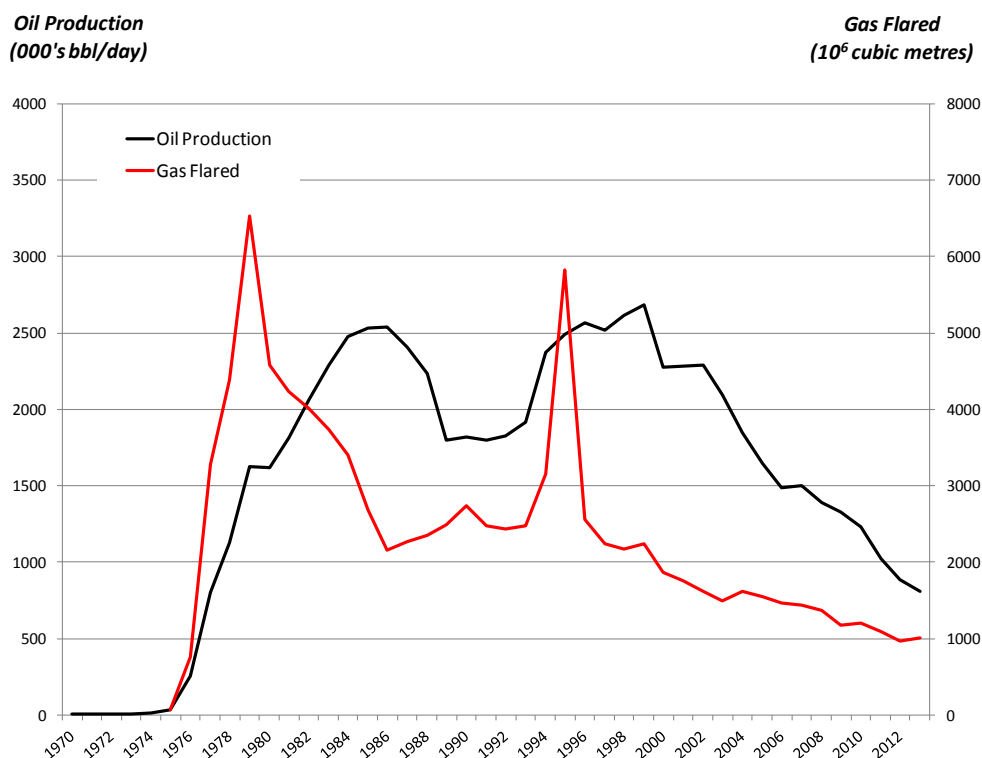
The Department of Energy and Climate Change (DECC) was responsible for both policy development and regulation of the UKCS, including environmental regulation. DECC was disbanded in July 2016 and merged into the Department for Business, Energy and Industrial Strategy. As part of the implementation of the recommendations of the *Wood Review*, the Oil and Gas Authority (OGA) was established in April 2015 as an executive agency under the Department for Business, Energy and Industrial Policy. OGA is set to become a fully independent regulator of onshore and offshore oil and gas developments in the United Kingdom by October 2016.¹⁰⁹

Data on gas flared has been routinely collected by the UK regulator since 1979. The data show that improvements have been made, albeit with somewhat erratic inter-year changes. On average, over the period 1980-2000, flaring dropped from around 7.7 cubic meters (scm) (271.8 scf) flared per barrel produced in 1980, to 2.2 scm (77.7 scf) per barrel in 2000. Average year-on-year improvements over the period showed about a 3% per year reduction in gas flaring on the UKCS.

¹⁰⁸ UKCS Maximizing Recovery Review: Final Report. 24 February 2014

¹⁰⁹ <https://www.gov.uk/government/news/launch-date-for-oil-and-gas-authority-government-company-announced>

Figure 20 UK oil production and UKCS gas flaring (1970-2013)



Source: US EIA, BP Statistical Review of World Energy 2016, UK DECC, Petroleum Production Reporting System (PPRS).

Regulatory overview

Responsibility for all aspects of oil and gas sector regulation, including gas flaring, has changed in time. Up until its disbandment, it lied with DECC, which was created in 2008 from the climate change sections of the UK *Department for Environment, Food and Rural Affairs* (Defra) and the energy, power sector and oil & gas sections of the former *Department for Business, Enterprise and Regulatory Reform* (BERR). Since April 2015, and with the disbandment of DECC in the wake of the establishment of the Department for Business, Energy and Industrial Policy, regulatory responsibility now lies under the Oil and Gas Authority (OGA) as an independent economic regulator.

The OGA is responsible for:¹¹⁰

- o Oil and gas licensing
- o Oil and gas exploration and production
- o Oil and gas fields and wells

¹¹⁰ As reported on the OGA's website: <https://www.gov.uk/government/organisations/oil-and-gas-authority/about>. Note that we assume that the regulations set out under DECC with respect to gas flaring have transferred over to the OGA in full. The OGA has not yet published separate documentation regarding gas flaring since OGA's founding and DECC's disbandment.

- o Oil and gas infrastructure
- o Carbon storage licensing

Much of the industry's activities are regulated under both European and UK law. In most cases, European Law is in the form of Directives that must be enacted into UK statute, although some European Regulations apply directly to the sector.¹¹¹ With respect to gas flaring, several efforts have been attempted to improve performance over recent years including:

- o The UK emission trading scheme – which ran from 2002 to 2009; and
- o The Flare Transfer Pilot Trading Scheme – which ran from 2000 to 2007;

Presently there are two main pieces of legislation regulating such activities:

- o The flare consents regime, since 1976;¹¹² and
- o The European Union Greenhouse Gas Emissions Trading Scheme (the EU ETS, since 2008)¹¹³

UK Flare Consents Regime

Since 1934, by way of the *Petroleum Production Act 1934*, as extended to offshore operations via the *Continental Shelf Act, 1964*, ownership of UK oil and gas reserves has been vested to the Queen and her Government. As such, oil and gas operators wishing to “*search and bore for, and get petroleum*” must apply to the Secretary of State for Energy and Climate Change, for exploration and production licenses to undertake such activities.

Gas flaring and venting has been regulated since 1976 under the *Energy Act* which first set down the obligation to obtain consent to flare gas from the Secretary of State. The associated *Petroleum (Production) Regulations of 1976* require offshore Licensees to design model clauses to not “*flare any gas from the licensed area*” without consent from the Secretary of State.

Most of the previous Acts and Regulations governing petroleum exploration and licensing have been consolidated into *The Petroleum Act 1998*. In doing so, the previous regulations model clauses were also consolidated into *The Petroleum (Current Model Clauses) Order 1999*.¹¹⁴ Accordingly, any operator wishing to flare gas must presently apply to the Minister, via the OGA, for a flare consent.

In practice, two procedures for flare consent applications are employed by OGA:

¹¹¹ The future applicability of all European Laws is currently in the balance due to upcoming ‘Brexit’ negotiations

¹¹² Enforced under the UK oil and gas production licensing provisions.

¹¹³ Under Directive 2003/87/EC and relevant UK enacting legislation including the Climate Change Act, 2008. Note that although the EU ETS started in 2003 (Phase I), gas flaring has only systematically been included in since Phase II (2008-2012).

¹¹⁴ Schedule 5, paragraph 21 (3) reiterates the prohibition on flaring without consent.

- o For fields flaring less than 40 tonnes of hydrocarbon gases per day, the operator may apply for a long-term (3 year) flare consent, provided that over the previous two years the operator has not applied to increase the flare consent. These require only the minimum of information to be completed in the flare consent application;
- o For fields flaring over 40 tonnes per day, the consent must be renewed annually.

Flare consents do not involve the completion of a specific application form, but rather involve a discussion with the OGA at least 3-4 months ahead of “first oil” or earlier, and then submission of a formal letter of application for a consent at least 2 weeks before “first oil” (see Box 1). Application for the renewal of existing Flare Consent follow similar, albeit less onerous, requirements.

Box 14 Flare Consent application procedures

The information required for an initial discussion with the OGA regarding a Flare Consent should include the following:

- o A description of gas plant and flare equipment to be commissioned. A description of how the wells will be brought on stream.
- o A detailed description of the plant start-up procedures and philosophy; the procedure for filling the gas export line should also be described.
- o The commissioning schedule.
- o Flaring calculations – to include flaring on a daily basis and total quantities. This should also show the target design flare levels for stable conditions once commissioning is complete.
- o Sketches and figures should also be supplied for the overall commissioning programme, the fuel gas system, the gas dehydration system, the gas compression system, the gas export system and pipeline and for the onshore facilities.

Initial consent application in the form of a letter, should include the following as a minimum:

- o Flare level for consent being applied for (usually for a 28 day period);
- o Justification of how this figure has been arrived at, including GOR rates etc.
- o Description of the work being carried out during the 28 day period.

An existing flare consent renewal can be made by providing information on:

- o A summary of the main points of the application.
- o A summary of the main flaring assumptions, including any flare reduction projects planned through the year
- o Flaring calculations – to include flaring on a monthly basis and total quantities.

Source: Oil & Gas UK (UK trade association), Environmental Legislation website and DECC's website.

A Flare Consent will specify the flare volume that must not be exceeded over a specified time, and is generally issued on a field basis. Where more than one field ties-in to common facilities at a production platform with the same field operator and licensee (a single composite or group) a flare consent may be issued to the installation operator. Where fields have different operators and licensees but a common processing facility, then individual applications for flare consents should be made – where all parties agree, it is possible to issue a single long-term flare consent if the field is not flaring greater than 40 tonnes of hydrocarbon gas per day. Conversely, if there are multiple facilities operating in one field (e.g. Forties field), only one flare consent will be issued for the whole field.

For either annual or long-term flare consents, if there is any possibility that the consented flaring rate for the period may be exceeded, including where a tie-back of new fields to a common facility is made, the operator must contact the OGA immediately to discuss any increases and difficulties encountered and if appropriate arrange for a revision of the consent. No carry forward of flare amounts between years (e.g. flaring below the consented rate in any given year) is allowed.

In terms of setting limits, according to *Oil & Gas UK* (a trade association for UK offshore oil and gas operators), DECC (and now the OGA) had an objective to **reduce non-safety related flaring by 5% per year**. However, the **general approach to achieving reductions is through close cooperation between the OGA and the operators, rather than through setting prescriptive limits**.¹¹⁵ This approach notwithstanding, *Oil & Gas UK* notes that it has been left to individual Field Teams to decide how to meet that objective: the Southern North Sea Field Team (London-based staff of *Licensing and Consents Unit-Licensing Exploration and Development (LCU-LED)*) have decided to meet the objective by an across-the-board reduction in flare consents. The Aberdeen-based staff (i.e. the OEU, covering the Central and Northern North Sea; West of Shetland Field Teams – see below) have decided to take a different approach, and are assessing proposals on a case-by-case basis to achieve the same overall reduction.

It is useful to note that DECC apparently took account of four categories of flaring to help inform the basis of decisions with respect to flare consents:

1. *Category 1 Base Load Flare* - this includes all the gas used for safe and efficient operation of the process facility and flare system under normal operating conditions.
2. *Category 2 Flaring from Operational or Mode Changes* - this includes gas flaring resulting from the start up and planned shutdown of equipment during production amongst others.
3. *Category 3 Emergency Shutdown/Process Trip* - this includes any gas flared during an emergency.
4. *Category 4 Unignited Vents* - this would fall under the Vent Consent not the Flare Consent

EU ETS and gas flaring

The EU ETS Directive sets out requirements for all qualifying installations – generally large point sources of GHG emissions – within the 28 member states of the European Union, to participate in a greenhouse gas (GHG) cap-and-trade scheme. It commenced in 2005, with Phase I running as a trial over three years to the end of 2007.¹¹⁶ Phase II ran from 2008-2012, and Phase II commenced on 1st January 2013 and ends on 31 December 2020.¹¹⁷ Under the

¹¹⁵ http://www.ukooaenvironmentallegislation.co.uk/contents/topic_files/offshore/Flaring.html

¹¹⁶ Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, and amendments. This has been transposed into UK law through various Acts, including *The Greenhouse Gas Emissions Trading Scheme Regulations, 2012*.

¹¹⁷ There is currently no official indication of how the UK's obligations under the EU ETS may change amid 'Brexit' negotiations.

legislation, operators of qualifying installations must monitor their GHG emissions¹¹⁸ over a calendar year and report these to the relevant competent authority by 31 March of the following year, and thereafter by 30 April surrender emission rights certificates, known as EU Allowances (EUAs) or other fungible trading units,¹¹⁹ equal to the corresponding monitored and reported emissions in tonnes CO₂ for the previous year.

EUAs were initially allocated freely to all participants, although in the latest phase (Phase III), only those industries at risk of “carbon leakage” receive a free allocation EUAs of up to 80% their emissions;¹²⁰ all other participants are required to purchase EUAs through a European Commission-run auctioning process, or through the secondary market in EUAs.

All UK offshore oil production installations qualify under the scheme through the presence of large (>20 MW) power plants located on production platforms. Gas flares, however, have only been formally included as qualifying installations under the scheme since revisions came into force in 2008, when Phase II commenced.¹²¹ The oil and gas industry, whilst considered to be at risk of carbon leakage through trade exposure, will receive only limited free allocation of EUAs in relation to all non-electricity generating emission sources (i.e. no free allocation is provided for electricity generation emissions); “safety flaring” qualifies for free allocation.

The GHG emission reduction targets imposed by the scheme are set in accordance with EU objectives for community-wide emission reductions, which subsequently determines the amount of EUAs allocated and auctioned to participants, as well as the limits set on the use of other fungible compliance units (i.e. CERs and ERUs). This in turn sets the market price for EUAs and other compliance units (see below). Under Phase III of the EU ETS the overall level of EUAs available in the “cap” reduces by 1.74% a year in line with EU emission reduction targets to 2020.

Effectiveness of regulation

UK Flare Consents

It is difficult to measure the success of recent efforts to reduce flaring since the North Sea is now a mature province that is in long-term decline, meaning that there is limited appetite for investment into large-scale infrastructure projects such as associated gas gathering systems. As such, improvements in current performance are reliant on reducing low-level continuous (or “baseload”) flaring through novel approaches,¹²² gas reinjection, and the tie-in of new sources of associated gas to the existing gas export infrastructure. Moreover, since

¹¹⁸ The scheme is largely restricted to carbon dioxide emissions only.

¹¹⁹ Primarily Certified Emission Reductions or Emission Reduction Units generated under the Kyoto Protocol’s clean development mechanism and joint implementation schemes, respectively.

¹²⁰ Carbon leakage refers to the situation where, due to competitiveness impacts driven by the increased operating costs posed by EU ETS compliance, trade exposes emissions intensive industries move production outside of the EU to areas not subject to emission costs. Such movements could lead to a net increase in emissions, a process widely referred to as carbon leakage.

¹²¹ Prior to that, there was differential interpretation of Directive 2003/87/EC as to whether gas flares qualified or otherwise. This meant some EU Member States, namely Denmark, included flares in phase I, whilst others such as the UK did not.

¹²² For example, improvements in reducing platform blowdowns, and use of enhanced flare gas recovery systems such as flare ignition systems to eradicate continuous pilot burners.

the flare consents regime has been in place since at least 1976, it is necessary to look at the historical development of the UKCS, the changes in flaring over time, and the possible reasons behind this.

As previously shown in Figure 17, the level of gas flaring on the UKCS has decreased significantly since its absolute peak in the late 1970's and suffered another peak around 1995.

The reductions achieved in the UK through the late 1970s and early 1980s can be attributed to the development of major gas export pipelines in the North Sea. These projects were implemented at a time when political concerns were heightened regarding the UK's energy strategy, especially in light of a serious economic recession and a heavy reliance on coal-fired power generation for electricity supply. The passing of the 1976 *Energy Act* was partially an attempt to address such concerns through the prohibition of gas flaring without consent from the government. This could be viewed as the key trigger in incentivizing operators to build associated gas gathering infrastructure.

The other period of significant improvements can be seen to be from the mid-1990s and this again can be linked to the development of new gas export systems. This can be attributed as a response to increasing energy prices at the time, and increasing demand for natural gas as a result of privatization of the UK's electricity sector and the subsequent "dash for gas". The reasons behind the dramatic spike in flared gas quantities around 1995 are difficult to ascertain, and could be due to the re-entry of closed wells and re-commissioning of existing platforms as production increased over the period as the aftermath of the Piper Alpha explosion and global oil prices took an upward turn.

EU ETS

The EU ETS has only been applied to gas flaring since 2008, and is therefore difficult to evaluate in terms of its impacts on gas flaring. Whilst the EU ETS has imposed additional costs for operators for gas flaring, this is significantly reduced where a free allocation is received by operators for "safety flaring". Furthermore, the marginal financial impact is dependent on the market price for EUAs, which has varied over the period from highs of around €28 per EUA in mid-2008, to the current levels of under €5 per EUA. These price changes have been caused by systemic issues with the EU ETS, driven by economic slowdown in Europe. Political efforts are presently underway by the European Commission and Parliament through proposals for "back loading" of EUAs through Phase III. This could lead to a short-term supply constraint on EUAs in the period 2015-2017 with resultant price increases.

A1.3.2 Oversight framework

Monitoring processes

In the UK, the two regulatory schemes – the Flare Consents and EU ETS – impose different monitoring rules and requirements for operators. However, both were overseen by DECC (and now the OGA).

Flare consents, PPRS and EEMS

Statutory reporting of mass/volume of gas flared is required as part of the compliance regime for Flare Consents. Whilst DECC provides only limited information on the methodologies and reporting requirements, *Oil & Gas UK* indicates that the following must be sent to DECC for the previous reporting period (as specified in the Flare Consent):

- o Short technical summary of performance of gas handling plant, highlighting any features which have affected or could affect the operation of the plant.
- o Rates in respect to oil production, gas production, gas export, gas used for fuel and of gas flare.
- o Cumulative average production for production and flare.
- o Calculations of gas compression plant efficiency.

It indicates that some Flare Consents may include the provision that specific monthly flare reporting is not needed and that flare volumes should be reported annually in the routine field reporting into DECC under the *Petroleum Production Reporting System* (PPRS). This is a requirement of the operators overall license conditions. The PPRS form contains a range of data disclosure obligations covering production volumes etc., and should include data on volumes of gas flared at field (and other gas flaring, where applicable). In the case where only annual reporting is required, specific flare reporting would be by exception only if flaring is outside of the level in a field's Flare Consent. In addition, whilst operators are generally required to report daily and cumulative volumes and dry mass in metric tonnes of gas flared under the Flare Consent and PPRS, neither provide specific methodologies as to how data should be collected.

Operators have also historically voluntarily reported gas flared data under *Oil & Gas UK's Environmental Emissions Monitoring System* (EEMS). Whilst EEMS Guidelines are provided in relation to atmospheric emissions,¹²³ with respect to calculating emissions from flaring, they do not provide guidance on the systems to be used to collect data in terms of accuracy, precision and tolerable uncertainty, etc. Notwithstanding this current gap, historically EEMS did provide more guidance on matters such as data collection, monitoring standards etc. However, since 2008 these monitoring standards have been largely superseded by the monitoring requirements imposed under the EU ETS.

EU ETS

Under the EU ETS Directive, Article 6, operators must submit an application for a GHG Permit, which must contain a proposed monitoring plan for approval by the competent authority, in this case the OGA. The proposed monitoring plan must be in compliance with the EC Monitoring and Report Regulation (MRR). The MRR sets out the following requirements and standards for data collection on gas flares:

¹²³ The latest EEMS Guidelines for atmospheric emissions calculations are available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/136461/atmos-calcs.pdf

- o What to measure:

“When calculating emissions from flares the operator shall include routine flaring and operational flaring (trips, start-up and shutdown as well as emergency relieves). The operator shall also include inherent CO₂ in accordance with Article 48.¹²⁴”

- o Calculation of flare emissions:

*Flare gas emissions [tCO₂] = activity data [m³ or tonne flare gas] * emission factor [tCO₂ per m³ or t] * oxidation factor*

The MRR sets down specific guidance on how to derive each of the following information and the maximum permissible level of uncertainty in their derivation:

- o **Activity data**— typically involves continuous metering of the flare gas stream, with the level of maximum permissible data uncertainty varying according to different Tiers (1 to 4); higher Tiers require a lower level of uncertainty, and *vice versa*. The maximum permissible uncertainty, as determined by the Tier applied, has repercussions for the type of measurement or metering to be used, and therefore the cost of the measurement system. In practice, it means that the operators should meter flare gas at *Tier 3* level with a maximum permissible uncertainty of $\pm 7.5\%$ over the reporting year, unless the operator can show that it *technically or economically* infeasible to reach this level of uncertainty. In such cases, a lower Tier may be applied: *Tier 2* = $\pm 12.5\%$ and *Tier 1* = $\pm 17.5\%$. The approach taken must be outlined in the GHG Permit application, and approved by DECC.

- o **Emission factor**— The operator may use either of the following estimates:

“Tier 1: The operator shall use a reference emission factor of 0.00393 tCO₂/Nm³ derived from the combustion of pure ethane used as a conservative proxy for flare gases.

Tier 2b: Installation-specific emission factors shall be derived from an estimate of the molecular weight of the flare stream, using process modelling based on industry standard models. By considering the relative proportions and the molecular weights of each of the contributing streams, a weighted annual average figure shall be derived for the molecular weight of the flare gas.”

- o **Oxidation factor**— *The following applies:*

“Tier 1: The operator shall apply an oxidation factor of 1.

Tier 2: Either:

(b) standard factors used by the Member State for its national inventory submission to the Secretariat of the United Nations Framework Convention on Climate Change; or

(c) literature values agreed with the competent authority, including standard factors published by the competent authority, which are compatible with factors referred to in point (b), but they are representative of more disaggregated sources of fuel streams;”

¹²⁴ Inherent CO₂ means CO₂ that is contained in the flare gas i.e. originating from the reservoir.

As outlined previously, the annual monitoring report produced by the operator must be verified by an accredited third party prior to submission to DECC.

As these requirements apply to all gas flares in operation in the EU, including all UK oil production facilities, this is now the *de facto* standard for measurement for flare gas now in place across the sector in the UK.

Table 14 Summary of reporting requirements and obligations

| Process/Procedure | Brief description | Frequency |
|---------------------------|--|---|
| Flare Consents | Oil producers obliged to regularly report mass/volume of gas flared for check against compliance with consent. | Weekly, monthly or annually depending on terms of Flare Consent |
| PPRS | Annual returns filed to DECC covering all field data, etc. Some Flare Consents may only require annual PPRS reporting. | Annually |
| EEMS | Voluntary reporting scheme jointly implemented by DECC and Oil and Gas UK | Annually |
| EU ETS Monitoring Reports | Verified reports of flare gas CO ₂ emissions in the previous calendar year to be submitted. | Annually (by 31 March each year) |

Enforcement mechanisms

Penalties

Oil & Gas UK state in their guidance that it is unlawful in the UK to flare gas without a current Flare Consent and in extreme cases it could lead to withdrawal of an operator's production license. Any non-compliances should be reported through the routine flare consent reporting or, if there is no specific routine flare reporting, then breach of exemption conditions should be reported at month end as they occur. Early phone contact with DECC is recommended before consent limits are exceeded.

For the EU ETS, the cost penalty imposed is dependent on the prevailing EUA price, although for flaring this may be marginal given the scope for free allocation as described previously. Other civil penalties apply for e.g. not holding a valid GHG Permit. In addition, failure to surrender EUAs in time or to the sufficient level results in a penalty for operators of €100 per tCO₂ not covered by the surrendered EUAs, subject to increases in line with European index of consumer prices from 1st January 2013. The paying of the penalty does not absolve the operator of its obligation to surrender sufficient EUAs.

Inspections

In addition to regular reporting obligations under Flare Consents and the EU ETS, routine and non-routine inspections may be carried out by DECC Inspectors to ensure compliance with relevant regulations and permit conditions, and to ensure that operations are carried

out with due consideration to of environmental aspects. DECC inspectors are empowered to, *inter alia*:¹²⁵

- o Board any offshore installation, accompanied by any other person, taking any equipment they may require
- o Examine or investigate activities as considered necessary
- o Give a direction requiring any part of the installation be left undisturbed
- o Take any measurements, photographs or make any recordings as considered necessary
- o Take samples of any articles or substances on the installation and/or cause such articles or substances to be dismantled or subjected to any process or test
- o Take possession of any articles and substances and detain for as long as necessary
- o Require any person, whom the Inspector has reasonable cause to believe is able to provide any information, to attend at a specified place and time, to answer questions and to sign a declaration as to the truth of any answers provided.
- o Examine and take copies of any records which is considered necessary
- o Require any person to afford such facilities and assistance as the Inspector considers necessary to enable them to exercise any of the powers conferred on them by the relevant Regulations.

The frequency of inspections is determined on a risk-based approach according to the consideration of a number of parameters for the platform, such as:

- o Hydrocarbon type produced (oil, gas, condensate)
- o Quantity of permitted discharges/emissions (oil, chemicals, combustion emissions)
- o Location of installation
- o Age of installation
- o Time period since last inspection
- o Non-Compliance frequency and severity
- o Investigation and enforcement history

Any changes in conditions, such as takeover by a new operator, change in frequency or significance of incidents, or changes to infrastructure, may lead to changes in the frequency

¹²⁵ From: Offshore Environmental Inspectorate: Overview of Inspector Powers, Inspection Strategy and Inspection Aspects. Available online at: www.gov.uk

of inspections. DECC publishes the portfolio for individual Environmental Managers and Inspectors by operator online.¹²⁶

DECC report that an inspection will always commence with an opening meeting where the Inspector will outline to senior installation staff how the inspection is likely to progress and what their requirements will be. When the inspection is completed a similar closing meeting will be held where the inspection findings will be discussed.

Inspectors can choose to inspect a variety of aspects relating to offshore oil and gas activities. It is not possible to provide an exhaustive list, but such aspects may include:

- o Regulatory and permit compliance – including EU ETS and Flare Consents
- o Prevention and minimization of oil and chemical releases
- o Previous inspections

A1.3.3 The regulator’s role and capabilities

Interface between stakeholders

As highlighted previously, the UK oil and gas industry is represented by a trade association: *UK Oil & Gas* – formerly the *UK Offshore Operators Association* (UKOOA). It has a number of groups involved with government relations including:

- o *The British Offshore Oil and Gas Industry All Party Parliamentary Group* (APPG) – the group holds *ad hoc* meetings between industry and UK Members of Parliament on topical issues and other activities.
- o *The Cross Party Group* – for meetings between industry, Members of the Scottish Parliament, and other interested groups. It meets throughout the year at the Scottish Parliament.
- o *EU Issues Group* – this group covers liaison between industry and EU stakeholders such as Members of the European Parliament and the *Oil and Gas Producers Association* (OGP) in Brussels
- o *The Oil and Gas Industry Council* – this industry group liaises three times a year with DECC regarding current and forthcoming issues for the sector.
- o *PILOT* – a joint programme involving the Government and the UK oil and gas industry that aims to secure the long-term future of the UKCS and ensure full economic recovery of our hydrocarbon resources. It is chaired by the Secretary of State for Energy and Climate Change.

¹²⁶ Available at: <https://www.gov.uk/government/policies/providing-regulation-and-licensing-of-energy-industries-and-infrastructure/supporting-pages/environmental-regulation-of-offshore-oil-gas-and-carbon-dioxide-storage-activities>

The regulator's capabilities

DECC has a wide remit with cross-cutting interests. The oil and gas sector is primarily overseen by the *Energy Development Unit* (EDU) within DECC and various branches, units and teams thereunder.

Responsibility for environmental regulation of the offshore oil and gas industry within DECC resides with the *Offshore Environment and Decommissioning Branch* (OED) and within that the *Offshore Environment Unit* (OEU). The OEU consists of three teams:

1. *Environmental Policy Team (EPT)* – primarily responsible for developing and influencing domestic and international policy such that the exploitation of UK oil and gas resources is conducted with the objective of minimizing environmental impact.
2. *Environmental Management Team (EMT)* – primarily responsible for the assessment and approval of offshore oil and gas exploration and production and other activities. It has a team of 21 staff, of which 15 are technical.
3. *Offshore Environmental Inspectorate Team (OEIT)* – primarily responsible for regulating activities once offshore operations commence in terms of undertaking inspections as described above. It has a team of 33 staff, of which 20 are in the technical inspectorate, 6 are responsible for Environmental Management Systems, 6 for Regulatory Compliance, and 1 for Offshore Oil Spill Emergencies.

With respect to the OEIT and the Environmental Management Systems team, DECC maintains a number of information management systems including:

- o *The UK Petroleum Production Reporting System (PPRS)* – in which all data, provided by operators under the terms of their licenses, for oil, associated gas, gas flaring, dry gas, condensate and water production and water injection etc. is recorded. Data in the PPRS is used for a variety of purposes including for checking compliance with production licenses and flare consents, and for completion of EEMs data (see below). DECC publishes this data in a common reporting format to be completed by operators.¹²⁷ Statistics from *The Digest of UK Energy Statistics* are available online, which replaces the old paper “Brown Book”, at: <https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes>
- o *The UK Oil Portal* – is an electronic platform used by DECC and operators to upload PPRS and other relevant data and information, and to receive guidance from DECC. It also allows operators to submit various applications for e.g. well drilling, various environmental aspects including flare consents, decommissioning, field returns etc.
- o *The Environmental Emissions Monitoring System (EEMS)* – is maintained by UK Oil & Gas with DECC involvement – DECC consider it regards the EEMS

¹²⁷ Further details on the PPRS reporting system is available at: http://webarchive.nationalarchives.gov.uk/20121217190832/https://og.decc.gov.uk/en/olgs/cms/tech_papers/pprs_2000/pprs_2000.aspx

system as a key element in its environmental regulatory function. It is the mechanism through which oil companies can submit their environmental returns, which are used by DECC for government reporting requirements. It can also be accessed by operators via the *UK Oil Portal*.

A1.3.4 Lessons learned for Egypt

The UK has been committed to maximizing resource recovery and reducing waste from its hydrocarbons operations since 1976. The format of this commitment has been an imposition upon operators in the form of statutory obligations to not flare gas without consent from the Secretary of State. Although such an imposition could be seen as somewhat absolute, its Flare Consents regime is considered a light-touch approach to flaring regulation and is thus well received by stakeholders. Additionally, since the 2000s, gas flaring in the UK is also regulated under the EU's Emissions Trading System.

The success in reducing gas flaring is mainly attributed to the investment in infrastructure that ensured that operators have a means to export associated gas. Nevertheless, monitoring and oversight are clearly defined under the UK system, drawing the following key lessons for Egypt:

- o The criteria under which Flaring Consents are issued are generally set through a *negotiated process between operator and the regulator*, DECC (now the OGA). The negotiation process gives significant consideration to technical, health and safety or economic challenges related to reducing flaring.
- o Due to its dual regulation, enforcement is done *both by DECC and by the EU*. In the former's case, penalties are not clearly set out but seem to be determined on a case-by-case basis. Under EU ETS, penalties for flaring depend on the price at which EUAs are being traded at that point in time.
- o *Self-reporting by operators* is a key aspect for the oversight framework for DECC and the EU ETS. Two annual reports, the PPRS and EEMS, have to be filed to DECC on an annual basis covering all field data. The latter is a voluntary scheme jointly implemented by DECC and *Oil and Gas UK*.
- o Over 50 staff in DECC were responsible for environmental management and inspections at offshore facilities (not including health and safety inspections). DECC Inspectors carry out *routine and non-routine inspections* to ensure compliance with relevant regulations and permit conditions, and to ensure that operations are carried out with due consideration to of environmental aspects.
- o DECC maintains several *information management systems* with which to record environmental performance data. These are now coordinated through the UK Oil Portal, and shared platform for DECC and operators in which data and other aspects such as consent applications may be handled electronically.

A1.4 Country case study 4: Nigeria

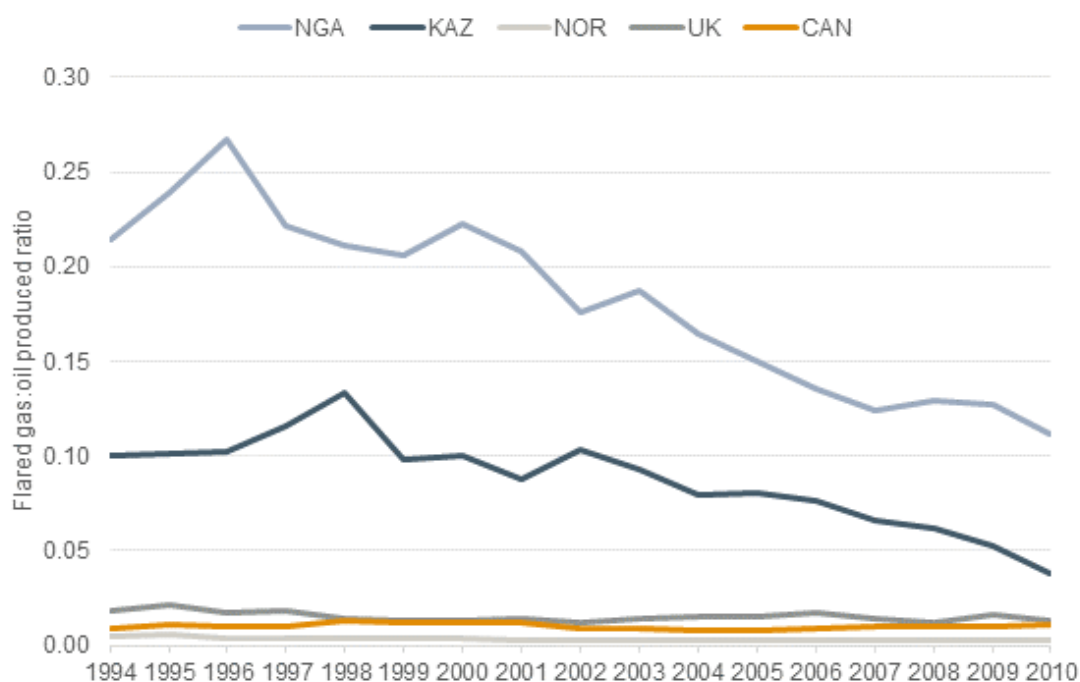
A1.4.1 Overview of sector and regulations

Sector overview

Nigeria has vast natural gas reserves in the form of associated gas. The country ranks ninth in terms of proven natural gas reserves worldwide, and the largest in Africa, with reserves estimated at 5.1 Tcm in 2015.¹²⁸ Despite the significant size of reserves, Nigeria only produced about 50.1 BCM of natural gas in 2015, ranking it as the 17th largest world gas producer.¹²⁹ In contrast, the volumes of gas flared stood at over 10 Bcm in 2012, making it the fourth largest gas flaring country in the world.

Nigeria has failed to utilize its abundant natural gas resource. In part this is because of a problem shared with other oil rich countries with associated natural gas: oil production has the highest value and the highest priority, and it is often difficult to schedule the production of natural gas in a way that satisfies the needs of gas consumers.

Figure 21 Flared gas to oil produced ratio, 1994-2010



Source: NOAA, *Global Gas Flaring Estimates, 1994–2010*; BP, *Statistical Review of World Energy, June 2016*.

Among our case studies, Nigeria has not been as effective as other jurisdictions over the years in limiting gas flaring relative to its oil production (Figure 21). While Nigeria, along with Kazakhstan, has gradually improved since the 1990s, this progress pales in comparison to the rapid reduction in flaring that was witnessed in Norway (Figure 17) or the United

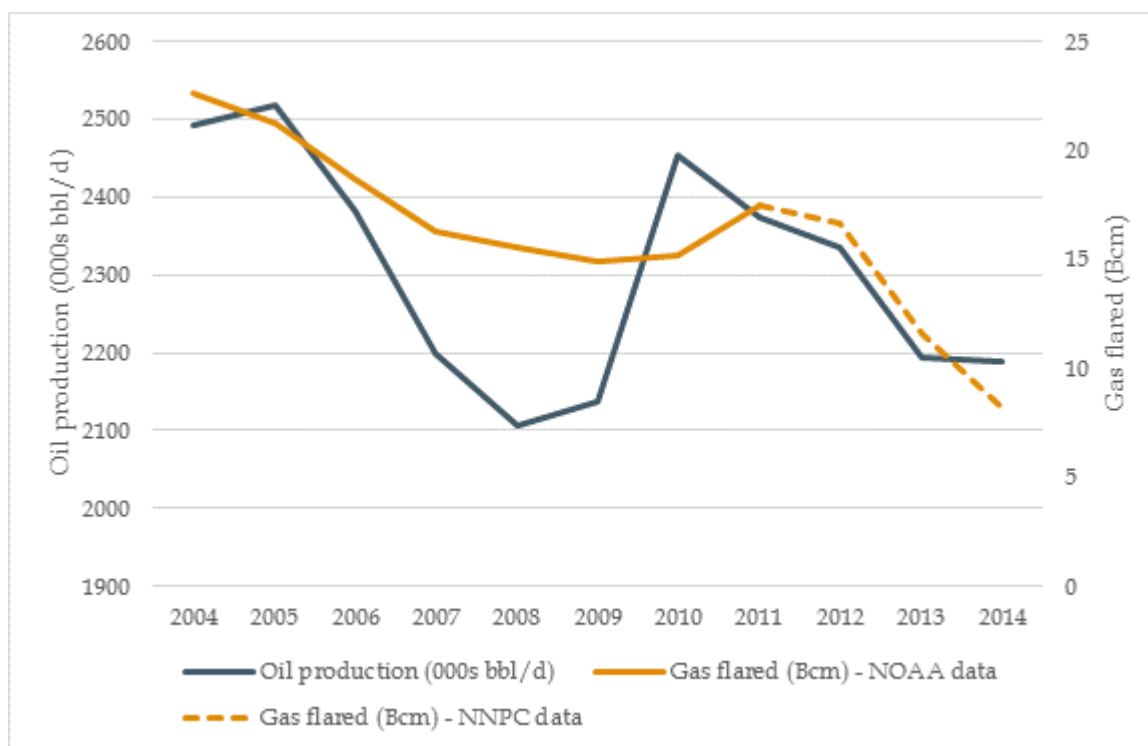
¹²⁸ BP, *Statistical Review of World Energy, June 2016*.

¹²⁹ BP, *Statistical Review of World Energy, June 2016*.

Kingdom (Figure 20). Nigeria's flaring performance has improved, but the improvement has, from a broader perspective, been from "absolutely terrible" to "very bad" (similar for Kazakhstan, albeit to a lesser extent).

According to post-2010 data from the Nigerian National Petroleum Corporation (NNPC), Nigeria has seen a further decline in gas flaring since 2011 (Figure 22). However, this appears to be in line with a recent decline in oil production rather than an improvement in the gas-to-oil flaring ratio.

Figure 22 Oil production and gas flaring in Nigeria, 2004-2014



Source: NOAA, *Global Gas Flaring Estimates, 1994–2010*; NNPC *Annual Statistics Bulletin, 2014*.

What declines have occurred for gas flaring in Nigeria can largely be attributed to a combination of the 'shut-in' of various fields in the Niger Delta due to concerns over security as well as the commissioning of various gas utilization projects, rather than any renewed government efforts to reduce flaring. In practice, it is difficult to determine the relative contribution of these factors. For example, Shell's joint venture in Nigeria (Shell Petroleum Development Company of Nigeria, SPDC) reduced gross flaring by 85% and flaring intensity by 70% between 2002 and 2015 but notes that this was due to both improvements in gas utilization and reduced production.

In 2014, only 88.5% of all Nigerian gas was utilized, as shown in Table 15 below, with the rest flared or vented. The main uses given to gas in Nigeria include 25.5% re-injection for enhanced oil recovery (also called energy industry own-use), 15.5% for LNG exports, and the rest sold domestically or exported by pipeline.

In Nigeria, priority is given to gas use for optimization of oil production, i.e. re-injection. Nevertheless, the only condition for an operator to produce gas for other uses is to submit a development plan. The deadline to do the latter is two years after initial oil production from that well.

Table 15 Nigeria gas production, flaring and utilization, 2014

| | |
|------------------------------|--------------|
| Gas flared and vented | 11.5% |
| Gas utilized | 88.5% |
| Sold | 28.2% |
| Re-injected | 25.5% |
| LNG | 15.5% |
| Fuel | 6.1% |
| Lift | 4.1% |
| Sold to NGC | 7.1% |
| LPG/NGL | 1.5% |
| Petrochemical | 0.4% |

Source: ECA elaboration based on NNPC Annual Statistics Bulletin, 2014

Regulatory overview

Policy on gas flaring reduction is formulated jointly by the *Federal Ministry for the Environment* (FMENV) and the *Department of Petroleum Resources* (DPR) which lies within the Ministry of Petroleum Resources. Policy is translated into enabling acts which are enforced by the latter as the responsible agency for gas utilization.

DPR was originally established in 1970 and changed several times due to the re-design of the energy sector's institutional structure. The most recent re-organization took place in 1988 and resulted in the separation of the inspectorate from the *Nigerian National Petroleum Corporation* (NNPC).

At present, the mandate over the regulation of gas flaring and venting from an environmental perspective currently lies jointly with DPR and FEPA, the *Federal Environmental Protection Agency*. DPR is the institution entrusted with issuing flaring permits, called Associated Gas Flaring Permits, while FEPA is the source of the EIA Guidance for Exploration and Production which operators are required to submit. As a consequence, operators are currently subject to two sets of regulatory provisions, none having precedence over another.

Additionally, state and local governments have the right to set up their own environmental protection body for the protection and improvement of the environment. Each State is also empowered to make laws to protect the environment within its jurisdiction.

The primary motivation for regulation of gas flaring and venting has been concerns over its local and global environmental impacts, particularly given the pressure from local communities and state governments in oil producing areas to provide improvements in environmental and social welfare. As previously mentioned, the benefits of increased oil production are seen as greatly outweighing the resulting losses due to waste of gas and, consequently, economic and commercial concerns over flaring are limited.

The regulatory approach to maximizing gas utilization in Nigeria was to set target dates for reductions and to prescribe penalties. The first flare-out deadline was set for 1984 and the

most recent ones were set for 2008 and 2010. It is unclear where the current deadline stands. This mechanism does not provide for operators to conduct tests of the economic or commercial viability of flaring reduction. Instead, operators are expected to develop plans and mechanisms to achieve the set targets.

At odds with the flare-out deadline are the efforts to increase oil production in Nigeria. For example, despite the setting of a flare-out deadline of 2008, investment in oil exploration and production was encouraged with a view to increase crude oil reserves to 40 billion barrels and production capacity to 4 million bpd by 2010, so as to support re-negotiation of Nigeria's share of OPEC quota. The consequences of this policy were:

- o The pace at which oil production capacity grew out-stripped development of upstream gas gathering infrastructure and the structural and regulatory reforms, necessary for the development of internal markets and downstream infrastructure.
- o Competition for funding between oil production and associated gas infrastructure resulted in inadequate funding being directed to meet gas utilization requirements and achieve flare reduction targets.

These consequences are shown in Figure 22 as the gradual decline in total gas flaring from 2004 to 2009 reverses to an uptick amid the post-2008 increase in oil production. This reversed as oil production began to fall again.

The latest effort by the government was to incorporate all legislation relating to Nigeria's petroleum resources into one piece of legislation under the Petroleum Industry Bill 2012.¹³⁰ The Bill provides for zero tolerance of gas flaring and venting from any oil field. Additionally, a fine is foreseen for non-compliance with the flare-out date to be established by the Minister.

The 2012 Bill also provides for the creation of an "Upstream Inspectorate" by transforming the existing DPR. It will be charged with overseeing gas flaring operations.

In summary, various flaring regulations in Nigeria have historically all followed a similar approach:

- o Government, through the Ministry of Petroleum Resources, sets a flare-out target for reducing flaring. It requires that industry, including NNPC, develop plans and mechanisms to achieve these targets.
- o The Ministry of Petroleum Resources, through the DPR, monitors compliance with these targets on the basis of industry reporting and facility inspections.
- o Penalties apply (in theory) for failures to achieve targets.
- o Plans for reduction are developed by individual operators. There are no tests of the economic or commercial viability of flaring reduction.

¹³⁰ A bill that has now been stuck in Nigeria's legislature for over 7 years: Klasa, A., 2015, 'Nigeria's oil bill: back to the drawing board', *Financial Times*, 9 July. Available online at: <https://www.ft.com/content/85f5b0c2-2618-11e5-9c4e-a775d2b173ca>

Effectiveness of regulation

The Nigerian approach has generally been ineffective at reducing gas flaring. Operators tend to disregard the framework altogether, listing the following reasons for its ineffectiveness:

- o The Nigerian government has generally set targets with little or no industry consultation. As a consequence, as operators perceive these to be unrealistic and make no efforts to achieve them.
- o The lack of tests for the economic or commercial viability of reducing flaring, imply that compliance with the regulation may prove unprofitable for certain operators. In this way, the setting of a flare-out deadline could create excessive regulatory burden.
- o Alternatives to gas utilization are easily available or cheap: instead of complying, operators have favoured either paying the small fines involved or seeking to obtain temporary permits.

In practical terms, the framework's ineffectiveness means that gas flaring is a better economic alternative to marketing the gas. The key barrier to the marketing of gas is that the domestic energy market to which non-flared gas could be supplied is not sufficiently developed, especially in rural areas. This makes another economic argument for flaring by oil and gas producers. As a consequence, international oil companies have been reluctant to invest in gas gathering and processing infrastructure as the government has failed to attract a viable domestic gas market to make it profitable for oil sector operators to produce gas.

Consequently, the reductions in gas flaring achieved up to date (Figure 22) are not a result of the existing regulatory framework. Instead they are seen as a result of a combination of increases in gas utilization activity and reductions in oil production.

A1.4.2 Oversight framework

Monitoring processes

All operators of oil and natural gas production and processing facilities must report gas utilization on a regular basis. *Monthly Gas Production and Utilization Reports* require each company to provide data on volumes of gas produced (associated and non-associated), gas utilized (re-injected, used as fuel and lifted) and gas flared (associated and non-associated). NNPC has made the template for such reports available online.

In accordance with the Mineral Oils and Safety Regulations of 1997, DPR requires that well testing is carried out on a monthly basis, which establishes oil flow and gas-oil ratio. These two parameters are used in calculating flaring volumes where meters are not installed.

At present, only new installations usually incorporate metering facilities for the measurement of flared volumes. Older and smaller facilities may not incorporate flare meters, and flared volumes are estimated.

The latest Petroleum Industry Bill of 2012, once passed, will require all operators to install metering equipment to measure flared volumes up to three months after the Bill is passed. Also, operators will be required to submit gas utilization plans. Six months after the Bill is passed, all operators should categorize their volumes flared:

"oil and gas operators with flared gas resources shall within six months of the commencement of this Act categorize all of their flared gas resources (daily flare quantity, reserve, location, composition) and submit this data along with gas utilization plans to the Inspectorate for the gas they intend to utilize before the flare out date as stated in section 275 of this Act."

NNPC collects and publishes gas production and utilization volumes regularly. This information is gathered from each operator's self-reports. These figures are publicly available on NNPC's Annual Statistical Bulletin¹³¹ and Monthly and Quarterly Petroleum Information¹³², published online on NNPC's website. Self-reporting obligations are likely to have resulted in operators to habitually underreport actual flaring levels (although NOAA data implies this may not always be the case) because inspections are rarely carried out.

Regular inspections are supposed to be conducted at upstream facilities in order to check whether operators correctly disclose their gas flaring levels, and comply with emission regulations and actions set out in the site's development plan. Both DPR and FEPA (through its State Environmental Agencies) have mandates to conduct inspections of sites they suspect of causing significant environmental degradation. However, it is widely recognized that the location of such facilities and the limited resources available to the regulatory bodies has created difficulties in effectively monitoring environmental and flaring performance.

No information was available on how inspections are coordinated between FEPA and DPR, or the criteria used for inspecting a particular site.

Enforcement mechanisms

Enforcement of flaring elimination regulations has never been carried out successfully. One key reason for this is that DPR and FEPA have conflicting jurisdictions and mandates regarding the implementation of flaring policies.

The Ministry of Petroleum Resources, through the DPR, has the authority to suspend or remove licenses and permits in the event of non-compliance with gas utilization regulations, but this sanction is rarely, if ever applied. Breaches of environmental legislation also carry the risk of prosecution of the operating company and its employees but this is again rarely used. In practice, sanctions are usually limited to the imposition of fines which appear to be ineffective in changing performance.

In recent years the Government has greatly increased penalties for flaring and further increases are planned. Where sites are licensed by DPR to continue flaring, the operator is obliged to pay a prescribed fee for each 1,000 scf of gas flared. Payment is made to a designated Federation Account through DPR, in the same way that royalties are processed. The current fee is US\$0.07 per 1000 scf of gas flared.

¹³¹ <http://www.nnpcgroup.com/PublicRelations/OilandGasStatistics/AnnualStatisticsBulletin.aspx>

¹³²

<http://www.nnpcgroup.com/publicrelations/oilandgasstatistics/mpifigures/monthlypetroleum.aspx>

More generally, a key problem in enforcing gas flaring regulations is that all calls for efforts and public statements have not been backed by law or codified. Often times, this failure was a result of disagreement from stakeholders with unrealistic or unfeasible deadlines and penalties. Without legal standing of flaring reduction regulations, the government lacks capacity to enforce these.

A1.4.3 The regulator's role and capabilities

Interface between stakeholders

Little information is available on the interface between stakeholders and the regulators, DPR and FEPA, although we expect that most of the interaction with respect to gas flaring and venting occurs directly between DPR and NNPC. There does not appear to be a stakeholder forum for other entities and the regulator to interact and align interests. As a consequence, most operators perceive flaring-out deadlines as unrealistic and choose to disregard them.

The regulator's capabilities

No information was available on DPR or FEPA's capabilities, particularly with respect to monitoring self-reported gas flaring and venting. As described above, we expect that a major contributor to the lack of monitoring and enforcement is under-resourced regulators.

A1.4.4 Lessons learned for Egypt

Nigeria's regulatory framework for flaring and venting is ineffective, largely due to its poor oversight framework. The factors contributing to its failure include the following:

- o Nigeria's regulatory approach of setting *flare-out deadlines*, which lacks tests for the economic or commercial viability of reducing flaring, means that compliance with the regulation will often be unprofitable operators. This means that DPR is faced with a significant challenge – monitor and enforce an unrealistic target that most operators will be very reluctant to meet.
- o Nigeria's flaring regulations *lack legal backing* and are thus difficult to enforce in practice.
- o Two agencies have a mandate to carry out regulation/inspection, generating *regulatory uncertainty for the operators*.
- o DPR, that seems to be the primary regulator, appears to *lack the resources to adequately monitor flaring levels* and compliance with permitted volumes. Inspections are rarely carried out. Instead, it relies largely on operators self-reporting.
- o *Fines for gas flaring have historically been set too low*, making it more profitable for operators to flare.

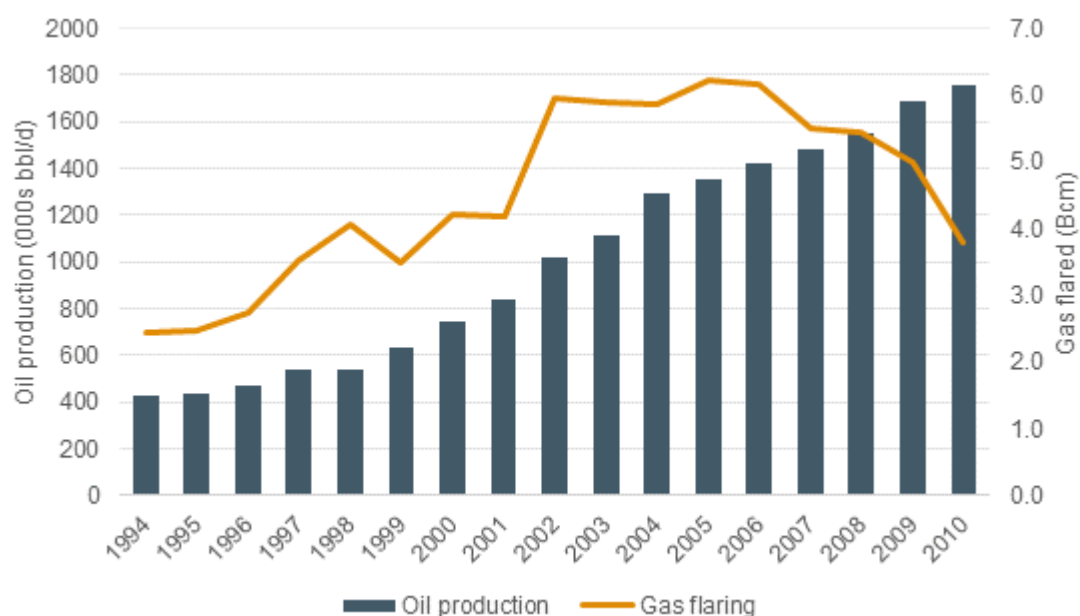
A1.5 Country case study 5: Kazakhstan

A1.5.1 Overview of sector and regulations

Sector overview

Kazakhstan is among the top 20 oil producing countries in the world. Production has grown very rapidly since the end of the Soviet Union, quadrupling since 1994. This has been accompanied by a rapid rise in gas flaring volumes, which (according to NOAA) data, increased from 2.5 BCM in 1994 to a peak of 6.2 BCM in 2005. Since then, despite continued growth in oil production, they have fallen substantially to 3.8 BCM in 2010. Figure 23 shows gas flaring and oil production developments in Kazakhstan for 1994 to 2010. More recent estimates of Kazakhstani oil production suggest it has plateaued in the 1,700 thousand barrels per day range since 2010,¹³³ while Figure 23, with the latest available figures, shows that Kazakhstani gas flaring remained around 4 BCM in 2012.

Figure 23 Flaring and oil production in Kazakhstan, 1994-2010



Source: NOAA, *Global Gas Flaring Estimates, 1994–2010*; BP, *Statistical Review of World Energy, June 2016*.

While 95% of Kazakhstan's flaring is accounted for by four areas, it is similar to Egypt in that reducing gas flaring in Kazakhstan has been hampered by the physical geography of its flaring. These gas fields are concentrated in the west, whereas much of Kazakhstani demand is further east. Gas transport infrastructure needs to be developed in the northern, central, and southern markets in order to better allow gas-capturing infrastructure to be linked with the gas-rich west.

¹³³ BP, *Statistical Review of World Energy, June 2016*. Note NOAA has not released an updated estimate of Kazakhstani gas flaring since the 2010 figures.

Kazakhstan has also been limited by its dependence on Uzbekistan and Russia for gas supply, who have sought to block the development of export-oriented pipelines in order to maintain their market shares. Should planned export pipelines eventually come online, they would greatly enable utilising APG via export.

Regulatory overview

The Government of Kazakhstan, through the Ministry of Oil and Gas (MOG), sets gas flaring and venting policy. Powers to regulate gas flaring and venting are derived from national legislation on subsoil and subsoil use. Besides the MOG, the Ministry of Environment Protection (MEP) also plays an important role in monitoring compliance with environmental regulations. Furthermore, the Ministry of Emergency Situations also plays a role under its mandate to monitor compliance with health and safety regulations.

Gas flaring and ecological permits are issued by the Committee on State Inspection in Oil and Gas Industry (CSIOG) and by the Committee on Ecological Regulation and Control (CERC) respectively. CSIOG (subordinate to MOG) and CERC (subordinate to MEP) are also responsible for monitoring and controlling individual quotas of flared gas and allowed CO₂ emissions.

Re-injection was the primary method of APG utilisation in Kazakhstan. However, the 2010 Subsoil Law sought to re-direct re-injections to commercial use by introducing an obligation to process APG and bring it to the market. Operators are obligated to develop an APG use plan, to be approved by the MOG. Any re-injections are only allowed if explicitly granted.

Effectiveness of regulation

Kazakhstan's first explicit targets on flaring were introduced in 2003, when a commitment was made to eliminate all flaring by 2004. Amendments to the 1995 Law on Oil prohibited gas flaring as of July 2006. This was unrealistic, requiring operators to essentially abolish overnight a process which up until then was considered an essential part of oil production. The effectiveness of the commitment was also undermined by apparently poor enforcement. More recently, there has been increased emphasis on the need for operators to demonstrate that there is no alternative to flaring, as well as large fines and penalties where unpermitted flaring does occur.

The Law on Subsoil and Subsoil Use, adopted in June 2010, partially rectified these concerns by setting the legal conditions under which technologically unavoidable gas flaring was allowed under certain circumstances, but gas flaring is still prohibited otherwise without a permit.

There have been successes, with the World Bank's Global Gas Flaring Reduction Partnership recently highlighting that a joint venture of Chevron, ExxonMobil, Kazmunaigaz, and LukArco have reduced gas flaring emissions by 94% at the giant Tengiz oil field. This accomplishment is particularly noteworthy given the gas from the Tengiz field is 'sour', making APG utilisation projects particularly costly. This case again highlights the need to consider the technological case for APG use on a case-by-case basis.

A1.5.2 Oversight framework

Monitoring process

An indicative utilisation target of 95% by 2012 is in place for associated gas. Associated gas is by far the largest source of gas flaring in Kazakhstan and the only regulated flaring source. Gas flaring is only permitted if one of the following conditions applies:

- o Suppression presents a severe environmental or health threat;
- o During testing of oil wells and oil fields; or
- o For maintenance, repair works or start-up operations.

Operators are obliged to process (commercially utilise) associated gas. Only under particular conditions and if the operator can convincingly show to MOG that it is not economically feasible to do so, is gas utilisation allowed (e.g. reinjection for enhanced oil recovery).

Any operator wishing to flare gas is required to hold a gas flaring permit issued by CSIOG giving allowed flaring volumes, an ecological permit issued by CERC determining the level of permitted CO₂ emissions and a feasibility study on how gas processing or utilisation at the facility will be developed.

Enforcement mechanisms

Regulations are enforced through fines on volumes of flared gas exceeding the permitted levels and ultimately suspension of operating licences in cases of breach of the licence conditions. Operators who flare gas, even within the allowed limits, are obliged to pay a tax, which local governments are allowed to increase to up to ten times the minimum level.

Since 2010, associated gas has been considered a property of the state, except if explicitly mentioned otherwise in the licence contract. This implies that government has the right to use flared associated gas free of charge and sell it onto global markets or to charge operators for foregone revenues valued at world market prices. This acts as a further penalty for operators and sends a strong political signal showing the commitment of government to reduce gas flaring.

As a modification to this, the 2012 Law on Gas and Gas Supply sets out that producers must make a gas sale offer to KazTransGas, based on the recovery cost of gas, the transport cost to the National Operator, the cost of converting raw gas to commercial gas, and a profit margin of no more than 10%. KazTransGas, with the approval of the MOG, may accept or reject the offer.

Kazakhstan also launched an Emissions Trading Scheme (ETS) in January 2013, which in effect further penalises flaring. However, further highlighting the underlying tensions with

industry, the scheme has been temporarily suspended until 2018 in the face of industry complaints about emission reduction demands being too strict.¹³⁴

A1.5.3 The regulator's role and capabilities

Interface between stakeholders

Kazakhstan's original failure to control gas flaring can be linked to the failure to properly consult industry stakeholders when legislation was first put in place. The immediate prohibition of previously allowed gas flaring announced in 2003 legislation came as a surprise to the industry, which suddenly had to figure out how to eliminate gas flaring that was essential for oil production, while also increasing oil production.

Subsequent legislation in 2010 and 2012 allowing for flaring in unavoidable circumstances have gone some way to address this issue, signalling a renewed commitment to engaging industry on this issue. However, by continuing to prohibit all gas flaring without a permit at a time when the effectiveness of actual regulatory enforcement appears to be low, Kazakhstan's current regulatory framework appears to be too ambitious.

The regulator's capabilities

There is some evidence that the effectiveness of regulatory enforcement is limited. There are large discrepancies between estimated flaring volumes from NOAA and the volumes reported by MEP. In 2009, NOAA estimated flaring volumes at 5 BCM, while MEP reported 1.7 BCM. In 2011, NOAA estimated gas flaring volumes at 4.7 BCM, while MEP reported only just over 1 BCM. Errors can arise from using satellite data to track gas flaring, but there has been a consistent discrepancy in Kazakhstan, suggesting underreporting is rife.

It is also reported that total fines in 2009 were only around US\$115 million while the assessed level of economic damage (assumed to be foregone revenues) were US\$3 billion.

A1.5.4 Lessons learned for Egypt

The failings of the Kazakhstani case highlight the importance of stakeholder interaction and a measured approach to gas flaring regulation. Ambitious regulations to reduce gas flaring may be admirable in spirit, but matter little if not properly enforced and if industry stakeholders have not been brought on board.

- o Kazakhstan *failed to properly consult industry* before essentially making gas flaring illegal overnight in 2003. Gas flaring actually increased afterwards as oil production continued to grow.
- o Kazakhstan has *numerous enforcement mechanisms* in place (fines, an obligation to offer APG to the state-owned operator, a briefly in place ETS), but actual enforcement (and reporting of flaring) appears to be lax.

¹³⁴ Carbon Pulse, 'Kazakhstan suspends ETS until 2018 - minister', 26 February 2016. Available online at: <http://carbon-pulse.com/16179/>.

- o Kazakhstan has deemed *marketing APG the highest priority way of utilisation*. Re-injections are only allowed with explicit permission. This may undermine the technological feasibility of APG use on a site-by-site basis, as processing APG is unlikely to be the most feasible option for every site.

- o Egypt faces a similar challenge as Kazakhstan in *coordinating infrastructure among spread out gas flaring sites* that are far from the main markets. Reductions in flaring will inherently be limited if such infrastructure is not put in place.