Associated Petroleum Gas Flaring Study for Egypt

Final Report
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Carbon Limits is a consulting company with long standing experience in supporting energy efficiency measures in the petroleum industry. In particular, our team works in close collaboration with industries, government, and public bodies to identify and address inefficiencies in the use of natural gas and through this achieve reductions in greenhouse gas emissions and other air pollutants.
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List of Acronyms

APG  associated petroleum gas
bbl/d  barrels per day
BCM  billion cubic meters
CAPEX  capital expenditures
CDM  Clean Development Mechanism
CNG  compressed natural gas
DMSP  Defence Meteorological Satellite Program
E&P  exploration and production
EBRD  European Bank for Reconstruction and Development
EGAS  Egyptian Gas Holding Company
EGPC  Egyptian General Petroleum Company
EOR  enhanced oil recovery
EU  European Union
FGRU  flare gas recovery unit
GANOPE  Ganoub El Wadi Petroleum Holding
GGFR  Global Gas Flaring Reduction Partnership
GHG  greenhouse gas
GOR  gas-to-oil ratio
GPP  gas processing plant
GRA  Gas Regulatory Authority
GTF  gas-to-fuels
GTG  gas-to-gasoline
GTL  gas-to-liquids
HSE  health and safety environment
INDC  Intended Nationally Determined Contributions
IOC  international oil company
IRR  internal rate of return
JV  joint venture
km  kilometer
kt  kilotons
kUS$  thousand US Dollars
kWh  kilowatt hour
LNG  liquefied natural gas
m3  cubic meters
MCM  million cubic meters
Mill  million
MMBtu  million British thermal units
MMscfd  million standard cubic feet per day
MRV  monitoring, reporting and verification
MUS$  million US Dollars
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>MWh</td>
<td>Megawatt hour</td>
</tr>
<tr>
<td>NAMA</td>
<td>Nationally Appropriate Mitigation Action</td>
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<td>NGL</td>
<td>natural gas liquids</td>
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<tr>
<td>NMM</td>
<td>New Market-based Mechanism</td>
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<tr>
<td>NOAA</td>
<td>National Oceanic and Atmospheric Administration</td>
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<tr>
<td>NPV</td>
<td>net present value</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>operation and maintenance</td>
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<tr>
<td>OPEX</td>
<td>operational expenditures</td>
</tr>
<tr>
<td>PAF</td>
<td>Pilot Auction Facility</td>
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<tr>
<td>PSC</td>
<td>Production Sharing Contract</td>
</tr>
<tr>
<td>SB</td>
<td>standardized baseline</td>
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<tr>
<td>scf</td>
<td>standard cubic feet</td>
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<tr>
<td>UER</td>
<td>upstream emission reductions</td>
</tr>
<tr>
<td>UK</td>
<td>United Kingdom</td>
</tr>
<tr>
<td>UNFCCC</td>
<td>United Nations Framework Convention on Climate Change</td>
</tr>
<tr>
<td>US</td>
<td>United States</td>
</tr>
<tr>
<td>US$/USD</td>
<td>US Dollar</td>
</tr>
<tr>
<td>VIIRS</td>
<td>Visible Infrared Imaging Radiometer Suite</td>
</tr>
<tr>
<td>VRU</td>
<td>vapour recovery unit</td>
</tr>
<tr>
<td>yr</td>
<td>year</td>
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</table>
1. Main conclusions

This report presents the main results from a Study commissioned by the European Bank for Reconstruction and Development on flaring of associated gas in Egypt. Assessments have been made of the potential for financially viable flare reduction investments, and policies and regulatory reforms have been explored which can trigger new flare reduction investments. Main conclusions from the Study are:

- Flaring is at a relatively high level in Egypt, measured per unit of oil production, and is caused by a number of economic and non-economic barriers to gas utilization investments.
- New policies and regulatory reforms can contribute significantly to flare reduction, for example through more explicit and clear rules for when flaring is allowed, and by stricter flare monitoring and reporting requirements. Improved, perhaps preferential, access to infrastructure for associated gas is also important.
- Production Sharing Contracts with "gas clauses" hindering associated gas utilization should be amended so that gas utilization investments can benefit all concessionaires.
- Flare sites in Egypt are mostly small scale. Only 7 sites (of about 70) have average flaring above 5 million standard cubic feet per day. The trend is towards more sites with small gas volumes which in many instances are located far from gas infrastructure.
- Small scale flare reduction investments are often uneconomic at current prices offered for associated gas. Typically the rate of return on investments could improve by 10 to 15 percentage points if the price is increased from 2.65 US$/MMBtu, often paid now, to 4 US$/MMBtu. The latter price level would better reflect the current “alternative value” of gas in Egypt.
- Until now delivery by pipeline has been the preferred option for bringing associated gas to market. With a shift in attention to stranded gas from new small fields in remote locations trucking of compressed natural gas (CNG) is expected to become more important. CNG starts to become the preferred option for small volumes which are further away than 15 km from a market outlet point.
- Use of associated gas rather than diesel to cover on-site power demand can be economically attractive. In addition, scalable and portable solutions can further justify exports of power supplies to the grid, but this is highly sensitive to the offered power tariff. An increase in the power tariff by 10 US$/MWh would typically increase the internal rate of return of the investment by more than 5 percentage points.
- Flare levels in Egypt can be expected to decline over the next few years even without additional efforts being initiated. This is because several relatively large flare reduction investments are underway. In addition, an important part of new production comes from gas-condensate fields, which often have little flaring. Finally, the low oil price may lead to a decline in new production. This does not mean that the flare problem goes away. New production of associated gas will increasingly come from small and remote sites, hence more efforts to avoid flaring will be required from political authorities and companies.
- A rough estimate shows that the capital requirements for elimination of all routine flaring by 2020 would be about 4 billion US$, assuming constant oil production. Further 3.5 billion US$ would be needed to avoid new flaring to emerge from 2020 to 2030, also under the assumption of constant oil production.
2. Introduction

This report summarizes the main findings from a project assignment, “Associated Petroleum Gas Flaring Study for Egypt” (the Study), conducted by Carbon Limits for the European Bank for Reconstruction and Development (EBRD). The objective of the Study has been to review the flaring situation in Egypt and identify and contribute to the development of a number of bankable gas utilization investment projects. Barriers to flare reduction investments have been identified and the role of regulation and policies to advance further reductions has been explored. Greenhouse gas emissions reduction impacts have been analyzed, as well as the potential role of carbon and climate finance to incite investments in flare reduction.

The EBRD has conducted the Study in collaboration with the Global Gas Flaring Reduction Partnership (GGFR) managed by the World Bank. It is related to the broader efforts of both the EBRD and the GGFR within the “Zero Routine Flaring by 2030” initiative¹. This initiative brings together governments, oil companies, and development institutions recognizing that routine flaring is unsustainable from a resource management and environmental perspective. Growing attention to the initiative signifies a broader support for a proactive stand on flaring reduction.

The EBRD has endorsed the initiative and is committed to support the aspiration of eliminating routine flaring by 2030. This study and the engagement of the EBRD in co-financing associated gas utilization projects should be seen in this context. The EBRD has already co-financed a few associated gas utilization investments in Egypt and is considering others.

The report first presents the flare situation in Egypt and compares it with trends and flare levels in other countries (Chapter 3). An overview of causes for associated gas being flared and a review of barriers to investments in utilization of associated gas are presented in Chapter 4. Chapter 5 deals with flare regulations and policies. The rationale for explicit and stringent flare regulations is presented followed by a brief review of existing policies and regulations in Egypt. Finally, this chapter presents elements of flare regulation which might be labelled as “best practise”, followed by some recommendations for regulatory reforms to be considered in Egypt. Chapter 6 includes a review of associated gas utilization options suitable for Egypt and a summary of investment cases analysed as part of this Study. Four cases were analysed comprising gas utilization options considered particularly relevant for flare reduction in Egypt. This chapter also includes a more generic analysis of factors which are important for the financial viability of small and medium scale flare reduction investments.

Chapter 7 presents a rough estimate of the capital requirements of meeting a zero routine flaring target by 2020, and further investment needs to avoid new flaring from 2020 to 2030. Finally, Chapter 8 discusses how climate policies and related international financial support might contribute to flare reduction efforts.

3. The flare situation

3.1 Egyptian flaring in an international perspective

Flaring takes place when gas produced in association with crude oil is not used for productive/energy purposes, due to lack of market outlets or for safety reasons. Estimates made from satellite images of flares (NOAA\(^2\) data) suggest that global gas flaring in 2014 was 142 billion cubic meters (BCM), comprising both associated gas flaring at oil fields and flaring at other facilities handling gaseous streams. Estimates are also available from other data sources, including national statistics. For many countries, including Egypt, there are major discrepancies between satellite estimates and national statistics with national statistics typically showing lower flare volumes. Causes for this include:

- **Underreporting in national statistics.** National statistics are based on reports from oil and gas companies which do not always measure gas that goes to flares, but rather make estimates of associated gas production and flaring, based on gas-to-oil ratios and other (indirect) parameters. Given that flaring is subject to regulations and penalties, there may also be a tendency that flaring is systematically underreported.

- **Uncertainties in converting data from satellites to flare volumes.** Conversion factors used by NOAA may for some countries overstate flare volumes. The fact that satellite images are not continuous measurements but “snapshots” represents a possible source of error.

- **Estimates from satellite images include more than flaring of associated gas.** Data published by NOAA/GGFR may include flaring of both associated and non-associated gas from gas processing plants and there may also be problems excluding refinery flares in the estimates.

Despite the uncertainties about actual levels, flaring is undoubtedly a massive resource waste and a significant environmental problem. If more than 140 billion cubic meters (BCM) of natural gas globally is flared on an annual basis, this amounts to an energy loss which alternatively could provide about 750 billion kWh of electricity, or more than the African continent’s current annual electricity consumption\(^3\). The greenhouse gas emissions corresponding to this flare level amount to at least 350 million tons of CO\(_2\) per annum, and the local health and ecological impacts of air pollutants can be significant, particularly in cases where flares are close to population centers and agricultural land.

Keeping in mind the uncertainty of the estimates, Figure 1 shows flare levels and flare intensities (flaring per unit of oil production), based on oil production statistics and satellite data\(^4\), of the 20 countries with the largest flare levels, including Egypt. Five countries had flaring above 10 BCM in 2014 (Russia, Iraq, Iran, USA and Venezuela), and when including also Nigeria (8.4 BCM in 2014) these countries accounted for more than 50% of global flaring. Flare intensities vary greatly, with USA and Russia being lower than other countries with high absolute flare volumes. Egypt had the 13\(^{th}\) highest flare level in the world in 2014 and was ranked around 25\(^{th}\) in terms of oil production, hence being above the average in flare intensity. Egypt has a flare intensity slightly lower than other countries in the region such as Algeria and Libya, but much higher than Qatar and Saudi Arabia.

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\(^2\) http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html. NOAA is a federal agency under the United States Department of Commerce.


\(^4\) VIIRS. Source: http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html
Policies and regulations to tackle the problem have been stepped up considerably over the past 10 to 15 years, and oil and gas companies have taken active steps to reduce flaring. Moreover, gas is increasingly in short supply in many countries and this has also promoted gas utilization investments. These factors have contributed to a 20% drop in global flare volumes from 2005 to 2012, but since then the global flare volume has hovered around 140 BCM per annum. Developments for individual countries, however, have shown major differences since 2012. Most notably, flaring in Russia, according to satellite estimates, has gone down 4.6 BCM from 2012 to 2014. This is more or less in line with national statistics which reports drop of 5 BCM for the same period. Further reductions can be expected to be recorded for 2015 as a large pipeline in Eastern Siberia was scheduled to come on stream and enable recovery of substantial volumes of associated gas. The second largest reduction was in Nigeria with an estimated reduction from 2012 to 2014 of 1.2 BCM.

Two countries stand out with large increases in flaring; Venezuela and USA both having increases in annual flare levels of 2 BCM for the period 2012 to 2014. Lack of investment and operational difficulties explain the increase in Venezuela, while the development in USA is part of a longer trend caused by the tight oil revolution. Iraq and Iran saw a rise in the flare level during the same period of 1.4 BCM and 1 BCM respectively.

It should be noted that countries with high flare intensities often have a skewed size distribution of flares. For example, in Russia 50% of the flared volumes are from about 20 large flare sites (of which some are part of one and the same license and/or operated by one company). Similarly in Iraq (South) and Iran there are some very large flare sites, and flaring in these countries can be substantially

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5 “Vankor-Khalmerpayutinskoye” pipeline, with a design capacity of 5.6 BCM per year.
6 It should be noted the most recent flare estimates published by NOAA is based on data from the Visible Infrared Imaging Radiometer Suite (VIIRS) differ significantly from estimates made by use of Defence Meteorological Satellite Program (DMSP) data. For example, the previous DMSP estimate for Russian flaring in 2012 was 35 BCM while the recent VIIRS estimate for the same year is 24 BCM. For Nigeria, the 2012 estimates were 14.7 BCM and 10 BCM respectively for the old (DMSP) and the new (VIIRS) programmes. See http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html.
reduced through a few large infrastructure investment schemes (which often seem economically attractive, but face both financial and non-financial barriers)\(^7\).

Although there are no firm statistics on flare levels and the size distribution of flare sites, it is likely that it is primarily at the large sites that gas capture and utilizations projects have been implemented in the past 10 years, both eliminating existing flares and avoiding flares at new production sites. Consequently, the size distribution has developed further in the direction of smaller sites becoming more important. With increased political attention, and focus and priority within companies, it is only natural that the large sites will be taken first, and smaller sites, often with poor or negative economic return, will have to wait. This view is also reflected in statements of the Zero Routine Flaring by 2030 initiative which says that oil companies should seek to implement economically viable solutions to eliminate routine flaring from existing oil fields (but with more stringent flare avoidance obligations for new oil fields)\(^8\).

Flare reduction efforts, both seen from a political and corporate perspective, will have to shift towards fields with medium and smaller scale flaring. Countries with oil production spread over large territories like Russia and the USA have a many small flares. Russia, for example, has some 300 smallest flare sites (out of 400 identified in total based on analysis of satellite data by Carbon Limits\(^9\)) accounting for only 3% of total flare volumes. It should be noted, however, that a large number of small flares are intermittent and not routine flaring, and as such are less relevant to consider for a Study like this. Still there are many small flares in a number of countries that should be accounted for as routine flaring\(^10\).

Egypt is also a case in point; flares are generally modest in volume with only 4 fields/concessions with flare volumes exceeding 7.5 million standard cubic feet per day (MMscfd\(^11\)), and there are indications that gas utilization investments are underway for the large existing flares. Since existing and new flare sites increasingly are small scale and in remote locations, this Study focuses on how efforts can be scaled up to gather and make commercial use of associated gas from such sites. The size distribution and location of flare sites in Egypt and covered in some detail in Section 3.4 below, after an overview has been presented of the recent flare trends (Section 3.2) and ongoing efforts to reduce flaring (Section 3.3).

### 3.2 Flare trends in Egypt

There are no official statistics in Egypt on production of associated gas and related flaring. Flare data is reported to the Egyptian General Petroleum Company (EGPC) by operators of production licences, but not published. Unofficially, however, data report to EGPC suggests a lower level than the one based on estimates from satellite data.

The flare estimates for Egypt used in this Study are from the Defence Meteorological Satellite Program (DMSP); until recently the source of NOAA published flare estimates. This source offers time series back to the mid-1990s and makes it possible to analyse flare levels for specific locations. Estimates

\(^7\) Basrah Gas Company, a JV with Shell, has e.g. announced that it is building 3 new compressor stations and rehabilitating an 40 inch pipeline to start capturing and treating gas from the West Qurna 1 field, with a target capture rate of 1.5 BCM/yr of gas that would otherwise be flared according to publicly available data.


\(^10\) As defined by GGFR in connection with launch of the “Zero-routine flaring by 2030” Initiative, routine flaring is defined as “flaring of gas during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas”

\(^11\) One MMscfd in average daily production is about the same as 10 mmcm\(^3\) (million cubic meters) per annum.
from this source (see Figure 2) indicate that the flare level in Egypt has been between relatively stable over the past 20 years and more or less have followed the trend in crude oil production.

Figure 2: Flare volumes (oil production and gas processing) and oil production in Egypt in BCM per annum (1995-2012)

Sources: BP Oil production statistics, GGFR flaring estimates produced by Satellite observations. Estimates for 2012 come from Carbon Limits analysis.

Only in March 2016 NOAA published satellite estimates using the new VIIRS data source. While the old DMSP showed 2012 flare estimates for Egypt of 2 BCM, the new VIIRS estimate is 2.5 BCM for upstream flaring (oil sites and gas processing plants), increasing to 2.6 BCM in 2014.

Since the new satellite data were not available during the time of the work conducted in this Study, the DMSP estimates from 2012 have been used for the analysis of flare locations etc. presented in this section of the report.

3.3 Ongoing flare reduction efforts in Egypt

Since an important part of total flaring is accounted for by a few fields or concessions, significant reductions can be achieved through gas utilizations investments decided by a relatively small number of operators and joint venture partners. The project team for this Study has not had a full overview of projects that have been commissioned over the past few years, but a review has been done of projects which are expected to have an effect after 2015. The result of this is summarized in Figure 3.

The review is based on data collected from 11 operators of concessions which account for 2/3 of total flaring as reported by EGPC. Over the next 2-3 years the operators estimate flare reduction to be about 35 MMscfd. This is a reduction of about 50% for fields covered by the review. It is not known whether operators of fields not covered also have investment plans for flare reduction, but it is

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12 Compiling flare events from VIIRS Satellite (Source: http://ngdc.noaa.gov/eog/viirs/download_viirs_fire.html) over a period of time (March – December 2014). Aggregating flares at identified oil fields. Weighting of the flares based on their radiation, which it is a function of temperature of the flare and observed size of the radiation. country estimated flare level

13 http://www.ngdc.noaa.gov/eog/viirs/download_global_flare.html
probable that there will be a decline also from those fields, at least through natural decline in production.

If the flare reduction investments are realized as expected this would imply a shift in the size distribution of flare sites since many of the gas utilizations projects are targeting (relatively) large flare sites (see Figure 3).

Figure 3: Overview of the impacts on flaring of ongoing and planned gas utilization investments

Sources: Data submitted by operating companies and EGPC, and Carbon Limits analysis

How distinct that shift in size distribution will be depends on the entry of new flare sites as new production comes on stream (see Section 3.4 below).

3.4 Size distribution of flares

In international comparison, flares in Egypt are relatively small in terms of volume. Some of the large and older crude oil production sites in the Gulf of Suez make productive use of associated gas for energy purposes, or the gas is re-injected into the reservoir. There are remaining flares in the Gulf of Suez, but a marked shift has taken place to new production sites in the Western Desert. Based on satellite imagery from 2012, the location of flare sites in Egypt are shown in Figure 4. This information has identified 73 flare sites, with the height of each stack indicating the relative volume of flaring.
Flaring volumes are equally divided between three regions; the Gulf of Suez/Sinai/Eastern Desert (hereafter called Gulf of Suez) and two regions of the Western Desert: i) the West, including Alamein ii) the North West comprising primarily of older production in Shoushan sub-basin and new production in Northern Egypt Basin. Oil production and flaring have increased in the North West and its share of flaring was at 36% in 2012. The North West has slightly higher flare intensity than the West, and the whole of the Western Desert has more than 60% of Egypt’s flaring but only half of oil production. Some of the largest flares were identified at new production sites in the North West but there was (in 2012) also considerable flaring from fields with a long history of oil production.
Table 1: Flaring levels on each region

<table>
<thead>
<tr>
<th></th>
<th>North West</th>
<th>West</th>
<th>Gulf of Suez</th>
</tr>
</thead>
<tbody>
<tr>
<td>Share of total flaring (2012)</td>
<td>~36%</td>
<td>~26%</td>
<td>~38%</td>
</tr>
<tr>
<td>Development from 2010 to 2014</td>
<td>increasing↑</td>
<td>Fluctuating, stable</td>
<td>Decreasing↓</td>
</tr>
<tr>
<td>Share of oil production (2012)</td>
<td>~ 30%</td>
<td>~ 20%</td>
<td>~ 45%</td>
</tr>
<tr>
<td>Flare intensity, m3 gas / m3 oil (2012)(**)</td>
<td>48</td>
<td>63</td>
<td>41</td>
</tr>
</tbody>
</table>

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

As can be seen from Figure 5, in 2012 there were only four sites with more than 7.5 MMscfd in flaring and these sites accounted for about 20% of total flaring in Egypt. Focusing on larger flares will therefore only solve part of the problem since the largest part of the flaring (~70%) are from sites have less than 5 MMscfd in flare volumes.

Figure 5: Size distribution of flares and number of flares in each category (2012)

Source: Carbon Limits analysis based on satellite data (DMSP, 2012)

The 73 flare sites identified are operated by 19 different companies. The five operating companies with the largest flaring (combined for all the licenses they operate) accounted for 70% of all flaring in 2012 in Egypt. Each of them had flaring, combined for all of their licences, in access of 120 MMscfd. Figure 6 illustrates this issue further, highlighting that two operators alone are responsible for over a half of the total amount of gas flared.
Figure 6: Share of total flaring by the 8 largest operators of flare sites (2012)

Source: Carbon Limits analysis and IHS E&P data

3.5 Access to infrastructure

Egypt has a relatively well developed oil and gas infrastructure (see Figure 7). There are some 200 pipelines, with different capacity and length, which bring gas from production sites to gas processing plants (GPPs). There are 9 GPPs located in oil production areas and additional GPPs located at the coast near gas and gas-condensate fields. They can be divided into infrastructure available in three areas:

Table 2: Summary of oil and gas infrastructure by region

<table>
<thead>
<tr>
<th>Area</th>
<th>Main pipelines</th>
<th>Main gas processing plants</th>
</tr>
</thead>
<tbody>
<tr>
<td>North West</td>
<td>(P3) Western Desert Gas Project-North 34” pipeline, which distribute to other gas distribution networks ¹⁴</td>
<td>[G1] Obeidiy</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EGAS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G2] Salam</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Apache</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G3] Tarek</td>
</tr>
<tr>
<td>West</td>
<td>(P1) Western Desert Gas Project-South 18-24” pipeline, which brings gas from Salam field in the Western Desert to the Dahshour hub, which is a hub of different lines. Bapetco (a EGPC/Shell JV) and EGAS operated</td>
<td>[G4] Abu El Gharadiq</td>
</tr>
<tr>
<td></td>
<td>(P4) Badr El Din – Ameriya, a 24” pipeline that joins Shell operations to Alexandria hubs ¹⁵</td>
<td>EGAS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G5] Dahshour</td>
</tr>
<tr>
<td>Gulf of Suez</td>
<td>(P2) Ras Shukheir – Suez 16” line. The line is operated by Egyptian Natural Gas Co (GASCO)</td>
<td>[G6] Trans-Gulf</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EGAS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G7] Ras Shukheir</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dana</td>
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<tr>
<td></td>
<td></td>
<td>Gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EGAS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G8] Gulf of Suez</td>
</tr>
<tr>
<td></td>
<td></td>
<td>[G9] Zeit Bay</td>
</tr>
</tbody>
</table>

¹⁴ Pipelines like El Ameriya – Cairo, El Ameriya – Alexandria and Alexandria - South Connection.

¹⁵ Ameriya Petro. – Refinery, Ameriya - Sidi Krir and Ameriyyah - Borj El Arab
What particularly matters in the context of associated gas utilization is the proximity of flare sites to pipelines and GPPs and the extent to which these have residual capacity and are designed to take the gas in question. These aspects need to be examined case by case, but some general observations can be drawn from available data.

Figure 8 summarizes some key data on proximity to pipelines for three regions. For the Gulf of Suez there is practically no flaring further away than 15 km from a gathering hub/pipeline. In the West 18 sites with around 0.15 BCM in total annual flaring have a distance of more than 15km to a tie-in point. As a whole, almost half of all flaring in Egypt is within 5 km from the nearest gas pipeline. Of sites far away from infrastructure around half had flare volumes below 1 MMscfd, which makes them “stranded” unless clustering opportunities arise.

Figure 8: Volumes of gas flared and number of flaring sites depending on distance to gas gathering pipelines or trunk lines by region
It should be noted, however, that the accessibility to tie-in points may be less favourable than these data shows since it is not known whether the nearest entry points have the capacity or technical conditions to take the associated gas in question.

3.6 Impact of new oil production

The analysis above suggests that total flaring towards 2020 may be reduced, even in a “business as usual” scenario without enhanced efforts in flare reduction. However, the development of future oil production is a key determinant for the flare trend. After a decline in oil production from 1995 to 2005 the production level has since then been stable. The downward trend in oil production was stopped for two reasons: i) liquid production from gas-condensate fields (NGLs) increased markedly with increases in gas production (see Figure 9) ii) enhanced oil recovery helped to slow the decline rate at many existing fields.

Figure 9: Crude oil and NGL production in Egypt 1994-2015

These factors have counterbalanced the impacts of a slowdown in exploration activities and fewer new production sites that followed after the political turmoil from 2012. However, after less than two years, issuance of exploration licences picked up again, but the question now is whether it will be sufficient to enable growth in exploration activities and new discoveries given the fall in the crude oil price.

For the purpose of the empirical analysis to follow in Chapter 7 (estimated of capital requirements for enhanced flare reduction efforts) two scenarios are made for oil production till 2020:

1. **Production remains stable at 0.7 million barrels per day.** This scenario is contingent on a recovery of the international crude oil price to an average level of 70-80 US$/barrel. Under such conditions both new exploration and field development and enhanced oil recovery will remain high. A stable production path in Egypt is in line with predictions in a recent report from the Energy Charter.\(^{16}\)

2. **Production declines gradually to reach 0.5 million barrels per day by 2020.** In this scenario it is assumed the crude oil price stays low (below or around 50 US$/barrel). This impact exploration and new development and lead to a faster decline at existing production sites as enhanced oil recovery increasingly becomes uneconomic. Condensate production

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may increase as the attractiveness of new production from gas-condensate fields will be less effected.

Figure 10: Oil production and consumption Egypt 1994-2020

Although flare intensity has been constant over the past 10 years, this will not necessarily continue for the period to 2020. There are different factors with an impact on flaring per unit of oil production for the next five years:

- Large flare reduction investments that are already underway, as described in Section 3.3, will contribute to lower flare intensity.
- Growth in the share of liquid production from gas-condensate fields may contribute to less flaring as the flare intensities of such fields are often lower than the average for crude oil fields. However it should be underlined that there are no statistics on flare intensities in Egypt which verify this assumption.
- If "new production" increasingly comes from enhanced oil recovery (less than from new fields/licenses) this could contribute to lower flare intensity (provided the existing fields/licenses already have gas utilization systems in place).
- The shift in production from the Gulf of Suez to the Western Desert contributes to higher flare intensity. As documented in Section 3.4, the average flare intensity in the Western Desert is significantly higher than in the Gulf of Suez, reflecting the remoteness and small scale of fields.

In summary, there are several factors that point towards a downward trend in flaring over the next five years even without additional efforts being initiated. Both a decline in oil production and lower flare intensity might contribute. On the other hand, new production of associated gas will increasingly come from sites where the market outlet can be problematic. This might neutralize the effect of the factors contributing to lower flare intensity. And more importantly, the new small scale and remotely located flaring sites will under all circumstances require more efforts from political authorities and companies in order to avoid flaring.
4. Flaring causes and barriers to flare reduction

4.1 Main reasons why gas is being flared

Effective policies and measures to reduce flaring must be based on a good understanding of flaring causes. In Figure 11, flaring causes are presented in three broad categories and further explained below.

Figure 11: List of flaring causes

<table>
<thead>
<tr>
<th>CAUSES OF FLARING</th>
<th>MEASURES TO REDUCE GAS FLARING</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CONTINUOUS («ROUTINE») FLARING</strong></td>
<td></td>
</tr>
<tr>
<td>1. Lack of primary gas utilisation outlets for (a part of) the gas produced</td>
<td>Develop or modify infrastructure to facilitate productive use of the gas</td>
</tr>
<tr>
<td>2. Other operational causes of continuous flaring</td>
<td>Install flare gas recovery systems and reduce HC pilot and purge gas utilization</td>
</tr>
<tr>
<td>3. Operational causes of intermittent flaring</td>
<td>Technical measures to improve regularity, optimizing procedures and staff training</td>
</tr>
<tr>
<td><strong>INTERMITTENT FLARING</strong></td>
<td></td>
</tr>
</tbody>
</table>

1. Continuous flaring caused by lack of primary utilisation outlets for produced gas

Continuous flaring is primarily caused by lack of market outlets, shortage of local demand or unsuitable geology for re-injection, among others accentuated by physical/technical constraints and/or poor economics of gas utilization investments. Flare reduction efforts often focus on reducing what is referred to as *routine flaring*. The recently launched “Zero-Routine Flaring by 2030 Initiative”\(^{17}\) defines routine flaring as “flaring of gas during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market”, which can be considered to comprise flare cause no. 1 in Figure 11.

2. Continuous flaring related to other operational causes

A number of other operational causes can also result in continuous flaring, e.g. related to operation of flare pilots, use of HC purge gas, degassing of produced water, glycol re-generation, sour oil treatment, etc. Though normally less important than category 1, this category can still represent significant volumes of flared gas. This type of flaring can for example be reduced by use of nitrogen purge gas, purge reduction devices or the optimisation of pilots, and even further by recovering low-pressure gases from relevant sources and operating without a lit flare (installation of Flare Gas Recovery Units (FGRUs) and Vapour Recovery Units (VRUs) which can bring the gas utilization rate to almost 100%\(^{18}\)).

3. Intermittent flaring

A variety of operational causes can cause intermittent flaring, inter alia:

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\(^{18}\) If used in combination with a flare ignition system.
• Pressure relief of equipment and facilities related to maintenance or modifications
• Start-up of new wells
• Shut-down and start-up of process facilities/compressors
• Temporary reduced capacity of primary gas utilization infrastructure (e.g. due to maintenance and shut-down of downstream facilities)

Some of the intermittent flaring can be reduced by improving the regularity of operations and by improving operational practices. Planning and execution of maintenance can often be better planned and optimized and personnel better trained. Such measures are often beneficial also from a financial perspective. The first category (continuous flaring due to lack of market outlets) is the most important cause of flaring on a global level and the category that receives almost all attention from political and regulatory authorities. It should be noted however that the two other categories can include significant flare volumes, and measures to reduce the flaring are in many cases as cost-efficient as for category 1. This has implications for policies and regulations, at least if the objective is to achieve reductions at the lowest possible costs (cost-efficiency).

4.2 Barriers

A number of barriers, some economic others non-economic, hinder associated gas from being productively utilized in Egypt. For the purpose of this Study the focus has been on barriers which can be removed and hence turn unattractive gas utilization options into viable investments. Four broad categories of barriers are relevant for Egypt:

1. **Technical and geographical barriers.** The large number of flare sites with low volume of associated gas is clearly an important barrier. Some of the sites are also scattered and in remote locations away from gas infrastructure, particularly in the Western Desert. However the terrain in Egypt makes it less expensive to build gas gathering lines than in many other countries.

2. **Structural barriers.** Different ownership to production/flare sites and gas infrastructure, including processing facilities and transport lines, often hinder gas being brought to markets. It has not been possible as part of this Study to get a good overview of the importance of these barriers in the case of Egypt, but it is noted that most flaring is with a small number of companies and the largest of these companies (Apache, ENI, EGPC) also have ownership to infrastructure. Moreover, EGPC has a 50% share in most production licenses and can through its dual commercial and regulator roles facilitate access to infrastructure and markets.

3. **Economic barriers.** This refers to economies-of-scale and external economic parameters such as gas and power prices, as well as taxes and other public incentive schemes, which may impact the financial viability of gas utilization investments. The current price of gas is clearly inadequate for the financial viability of many projects. In addition, there is no preferential treatment of associated versus non-associated gas supplies when it comes to market access and price. From a purely economic point of view this mostly makes sense since non-associated gas often is a more stable and higher quality source of supply.

4. **Awareness, knowledge and priority.** In the past, associated gas was considered a waste product, or by-product of crude oil production with little economic value. Among industry executives the attitude has changed, due to higher value for the gas, regulatory and political pressure and company internal standards. Still, investments in flare reduction must compete with other projects for financial, human and managerial resources, and beating oil production
expansion investments is often difficult. The fact that flaring and related environmental problems, including climate change, is not yet high on the policy agenda in Egypt further contributes to the relatively low priority flare reduction investments have among corporate managers. Generally it is easier to have funds allocated for gas utilization 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.

5. **Regulatory barriers.** Unlike in many other countries with flaring of associated gas, Egypt does not have any specific flare regulation. Flaring is covered through some environmental regulation, but in practice has little influence on flaring practices and gas utilization investments. The principal regulatory barrier is the treatment of associated gas in concession agreements and Production Sharing Contracts (PSCs). Generally flaring caps and gas utilization obligations are not addressed in terms set up for field developments and the PSCs typically give the state ownership to all associated gas which is not used at the production site.

Some of the barriers can be directly eliminated through changes in regulations and policies. Other are more fundamentally rooted in physical/geological and economic factors, and priorities set by corporate managers. The role of policies and regulations in removing barriers is discussed in the next chapter.
5. Flare regulation and policies

5.1 Rationale for policy interventions

In many oil producing countries political statements and ambitious flare reduction targets show that public authorities generally want to go further in flare reduction efforts than companies. Public interests have a longer time perspective and a lower discount rate than those of a private company, and tend to value natural resources and the environment differently. If environmental damages caused by company operations are not adequately regulated/penalized, and/or abatements are not rewarded in the market, companies would typically not act adequately in line with the public interest. Consequently, both resource management and environmental considerations call for policies and regulations so as to bring flaring down to the level considered politically acceptable.

As will be documented in this chapter, Egypt, unlike many other oil producing countries, does not have an explicit and forceful policy for flare reduction. This suggests that the economic, social and environmental benefits are not fully recognized, even if they are considerable and easy to identify.

If it is assumed that current level of routine flaring at oil fields is 1.5 BCM\(^1\), then flare elimination would bring gross revenues of about 140 million US$ using a (low) gas price of 2.65 per MMBtu (million British thermal units)\(^2\). If an import price of 7 MMBtu is applied, flare elimination could potentially save 370 million US$ in costs for energy imports. The energy brought to market could add some 7,000 gigawatt hours in annual power productions which represent 5% of current national production. Flare reduction can therefore make a notable contribution to Egypt’s precarious power supply situation. Finally, there are important environmental benefits as climate change is rising on the political agenda and in light of the health and ecological impacts of flaring.

As discussed in the previous chapter, there are barriers to flare reduction which cannot easily be removed (for technical, safety and economic reasons). Still, authorities must set a target for how far they want to pursue flare reduction, based on an overall costs and benefit assessment. Although it is often thought that it is the companies that carry the burden of flare reductions, it should be noted that state revenues losses from such investments can be considerable (depending on the relevant fiscal regime).

Having set a target, the next challenge is to design and implement policies and regulations so that the economically attractive reductions are taken before the costlier cases. This requires development of specific regulations which are clear and transparent, and which have data and reporting requirements that can be met at reasonable costs. Moreover, this system should be attuned to the management and enforcement capacity and capability of the regulator.

Bearing in mind these general considerations, the next section presents a brief overview of how flaring is dealt with in Egypt from the political and regulatory side, followed by a discussion of new policies and regulations which might contribute to cost efficiency in flare reduction efforts. The objective is to present approaches relevant for Egypt.

\(^1\) This is based on estimates from the DMSP satellite which indicate that the total upstream flare level in 2012 was 2 BCM, of which 0.3 is estimated to be from gas processing plants and 0.2 BCM non routine flaring from oil fields. As pointed out in Chapter 3, the new NOAA flare estimates based on VIIRS suggest that total upstream flaring in Egypt were 2.5 BCM in 2012 and 2.6 BCM in 2014.

\(^2\) This is the price typically being offered for delivery of associated gas.
5.2 Current framework for flare regulation in Egypt

Legal framework and institutional structure

Regulation relevant for flaring and utilization of associated gas should be considered in light of the key legislation related to the petroleum sector in Egypt, which dates back to 1953\(^1\), and the key public institutions involved. The most important institutions are:

1. Egyptian Petroleum Corporation (EGPC) formed in 1956 to manage the country’s hydrocarbon reserves on behalf of the state. Gradually during the 1960s and the 1970s EGPC formed joint ventures with international oil companies (IOCs) for exploration and development, and established license conditions, including Project Sharing Contacts (PSCs).
2. Egyptian Gas Holding Company (EGAS) established in 2001 to stimulate the development of the gas sector.
3. Ganoub El Wadi Petroleum Holding (GANOPE), formed in 2003 to take care of exploration and production in Upper Egypt which to date is little explored.
4. Ministry of Petroleum which formulates and implements oil gas sector policies, including preparation of legal and regulatory changes to be put forward for resolution by the Parliament and the President. The Ministry also plays a role in preparation for ratification of concession agreements.

EGPC, EGAS and GANOPE all have management and regulatory functions related to licenses and PSCs as well as being commercial partners in joint ventures. EGAS undertakes bidding rounds for licenses in the gas-prone areas of the Nile Delta and Mediterranean, while EGPC primarily covers the Gulf of Suez and the Western Desert and GANOPE Upper Egypt. Since EGPC is the primary state-owned subsidiary involved with exploration and development of oil fields, it is also the principal institution dealing with flaring and utilization of associated gas.

Major gas sector reforms are underway in Egypt which most probably will impact conditions for the supply of associated gas to markets and for the mandates of both EGAS and EGPC. A new Gas Law has been drafted and is expected to be passed by the Parliament during the first half of 2016\(^2\). Under this law a Gas Regulatory Authority (GRA) will be formed which takes over regulatory functions from EGAS. More importantly the law contains a number of new provisions for liberalizing the gas market and creating a competitive environment among market participants. Consumers will have the opportunity to choose their own suppliers, and gas suppliers will have access to the transport infrastructure based on a set of tariffs set by the GRA.

Exploration and development licences

Bidding rounds for exploration licenses are organized with different intervals. For the exploration phase the contractor company signs a concession agreement with EGPC/EGAS/GANOPE. There are several bidding parameters, most notably specification of work commitments, profit sharing and a signature bonus. Concessions need ratification at the political level.

In case of a commercial discovery, a Production Sharing Contract (PSC) is negotiated and a joint venture (JV) is established between EGPC/EGAS/GANOPE and the contractor company (normally an

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\(^1\) Principal laws for oil and gas sector activities are: Law no 66 from 1953 (Raw Materials Law), Law no 217 from 1980 (Law of organizing Natural Gas and executive regulation) and Law no 20 from 1987 (Law on EGPC). These and other laws have subject to a number of amendments.

international oil company, IOC), requiring 50% participation of EGPC/EGAS/GANOPE. The contractor company carries all costs. A development license is issued with 25 years duration for gas, and 20 years for oil. In the latter case there is a 5 year prolongation option.

An important feature of many PSCs is that recovered associated gas only belongs to the JV if it is used on site, otherwise it is for the benefit of the state only (normally through EGPC). Although a number of PSCs have been amended on this point, it still represents a principal barrier to flare reduction investments.

**Regulations and flaring**

There are no specific policies and regulations in Egypt targeted at flare reduction and increased associated gas utilization. Primary and secondary legislation relevant for oil and gas sector operations do not include specific text on flaring, but some flare relevant environmental regulations exist, such as:

“… the harmful smoke, gases, and vapors resulting from the combustion process are within the permissible limits”, and

“…the person responsible for such activity shall be held to take all precautions necessary to minimize the pollutants in the combustion products”.

Such issues are addressed within the context of Environmental Impacts Assessments required for exploration activities and any investments in new production. However, flaring independent of local environmental problems is not addressed in EIAs. This does not mean that flaring as a resource management problem is not addressed in investment decision making processes of JVs, but rather than there are no references to explicit legal and regulatory provisions in this regard.

More informally, EGPC have instituted requirements for when flaring is acceptable. For example, it seems that an upper limit of 1MMscfd applies for flaring at gas-condensate fields, while no threshold is set for oil fields. Still, EGPC puts pressure on operators of JV to find solutions for associated gas, but acceptable flare levels are higher for oil fields and are considered more “case-by-case” than for gas-condensate fields, most likely for the reason that the resource waste in relative terms are much larger in the latter case.

Operating companies report flare volumes to EGPC on a regular basis. The project team for this Study has been given access to part of this information. As noted in Chapter 3, large differences in the total level of flaring has been found between the data reported to EGPC and estimates based on satellite images. Although there are major uncertainties with estimates from satellite data, the analysis referred to here also suggest that there are deficiencies in data collected by EGPC. This may include both lack of full coverage of flare sites and underreporting from sites for which data are reported. There does not appear to be specific reporting instructions for flare data submissions, and the way operators actually calculate flare volumes differ. It is believed that reported flare volumes often are based on a variety of calculations methods other than direct measurements of gas sent to a flare stack.

**5.3 Elements to best practice regulation and policies**

Many oil producing countries have specific and stringent regulations of flaring and a conclusion from this Study is that Egypt can give a significant impetus to flare reduction by imposing clearer and more decisive regulations. However, regulatory approaches differ greatly between countries, often for good

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23 Regulation set by Law 4 of the Republic of Egypt
reasons since they are rooted in national legal structures, regulatory traditions and institutional realities. Hence, there is no blueprint or best practice for flare regulations, but there still are international experiences which can be considered as important elements for establishing effective and cost-efficient flare regulations. They are presented here together with a discussion of their relevance for Egypt.

Other means than direct flare regulations are also used by public authorities to spur gas utilization investments such as pricing policies and broader framework conditions for the productive use of associated gas. They are also briefly addressed in this section.

Flare regulations

Three important aspects of the regulatory system are discussed here:

i. Flare permits
ii. Monitoring and reporting
iii. Follow up and enforcement by the regulator

Flare permit

If flare restrictions are written into primary or secondary legislation, it is common to establish a procedure with issuance of flare permits. Often a threshold is set for when a flare permit is needed. Thresholds can be set as:

a) **Flare volume per unit of time**, e.g. MMscfd. This is the most commonly used variable for setting thresholds.

b) **Flaring as a percentage of total associated gas production**. Russia and a few other countries do not allow that more than 5% of associated gas production is being flared, signifying that only non-routine flaring is allowed.

c) **Flaring volume relative to the production of liquids**. The rational for this would be to avoid (relatively) large flaring at gas-condensate fields. Such regulations are particularly relevant if thresholds of the type a) or b) are not in place.

The next step is to consider whether exemptions to a flare prohibition (a flare permit) should be granted. For example, when a site has flaring in excess of the set threshold an exemption can still be granted on the basis of an investment analysis which document that the flare reduction is financially unviable. This would normally require that field specific circumstances and market conditions are considered. In such a case the operator may be required to present a techno-economic analysis to justify that flaring is technically and economically difficult to avoid.

In the process of granting flare permits it is essential to distinguish between new field developments and flaring from fields with existing production and infrastructure in place. It is particularly important to have more stringent regulations for new production when fields typically are small scale with relatively steep decline rates, as in Egypt. Empirical analysis done as part of this Study has shown that the economic return on gas utilization investments at new fields are higher both because costs are lower when incorporated in field developments from the start and because the investment would benefit from a longer economic life time. In flare regulation of new versus existing fields it is important to define what a new development is and what is only extension or modification to existing production.

As mentioned above routine flaring is normally the focus of flare regulation and policies. Operational flaring triggered by safety/emergency and other operational considerations attract little attention, to our
knowledge also in Egypt. Although the different categories of flaring may seem clear in principle, in practice it is not always easy to distinguish between them. As noted above, the different categories of operation flaring may account for significant volumes of gas and there are means to reduce them. For this reason there are arguments for regulatory authorities also to have focus on operational flaring.

**Monitoring and reporting**

Monitoring and reporting is essential for flare regulation to be cost-efficient and effective and for the companies to set the right priorities and undertake adequate measures. The quote “you cannot manage what you don’t measure” is very true in relation to flare reduction efforts, and highly relevant in the case of Egypt given the deficiencies that exist in monitoring and reporting of flare volumes.

Gas streams can be estimated based on gas-to-ratios (GORs), derived from reservoir studies and/or production samples, or through direct measurements conducted by ultrasonic or other gas flow meters. The latter can be expensive and can also be impractical under certain operational conditions. When flare permits are being considered as part of field or license development processes, associated gas production obviously would have to be based on GOR estimates, but there may be certain requirement as to the empirical foundation of these estimates. Once production has started, measurement and reporting requirements would typically be determined by the volume thresholds and possible hazardous types of flaring.

Flaring incidences caused by operational factors can be significant and are often cost efficient to reduce. Companies typically record flaring incidences but this information is seldom used for the purpose of developing company-wide strategies and procedures for the minimization of operation flaring. Regulatory authorities may help instigate more attention being assigned to operational flaring, e.g. by designing reporting templates for flare categories, causes and possible mitigation measures. Only a few countries, including the United Kingdom and Brazil, have clearly defined criteria for justifying operational flaring.

**Follow up and enforcement**

Companies may not have good flare data or they may have a (perceived) interest not to reveal all information they have. An “information bias” between companies and the regulator can also be the result of lacking capacity and capability with the regulatory institution(s), not the least caused by the complex and technical nature of flaring issues. There are two implications of this for setting reporting requirements and for interaction between companies and the regulator:

1. Regulatory procedures, including granting of flare permits, must be adapted to institutional capacity and capability and data requirements should be such that information of sufficient quality realistically can be retrieved from companies.

2. Companies should be encouraged to monitor and report data of good quality and/or penalized if reported data are inadequate or erroneous.

There are many examples internationally of ambitious and often elaborate regulatory requirements and procedures, but a lack of capacity and ability to follow up. Ambitious targets and lack of compliance and enforcement are therefore widespread. This calls for building capacity and capability at regulatory institutions, and giving them a clear mandate not overlapping with other public institutions. It should be noted that this takes a long time to establish. In the meantime it is essential that regulatory provisions and procedures are in line with the institutional capacity which is in place.
Country examples

Typically there are two main approaches for setting thresholds for when flaring is allowed/not allowed:

i) an absolute and single threshold which applies to a site or concession

ii) setting thresholds case by case based on negotiation with the operator. Example of the first approach includes the case of Russia, where only 5% or less of the produced gas can be flared without penalties. The second approach is more widely adopted, although the extent and level of case by case review and dialogue between the regulator and the operator vary by jurisdiction. Three jurisdictions are mentioned here, namely the United Kingdom (UK), Texas (US) and Alberta (Canada).

In all three jurisdictions a distinction is made between flaring which does require approval and flaring which need consent (permit to flare). The terms routine and non-routine are not used but flaring caused by emergency situations and/or safety risks are allowed. In the UK, consent application should include medium and long term plans for flare reduction, with supporting information, and therefore no blanket threshold on the amount of the gas flared exists, as this figure is determined in individual consent applications. In Texas consents are also provided case by case based on the volume of gas flared and other information. With respect to reporting, this is prepared on a monthly basis in all three jurisdictions. In all three jurisdictions, non-compliance may eventually lead to withdrawal of the license, although this is considered to be the last resort.

In all three jurisdictions economic criteria are used as assessment criteria for awarding flaring consents. In Texas a future gas utilization plans (incl. cost-benefit analysis) should be provided in order to obtain a long-term permit, which should include a map showing nearest pipeline capable of accepting gas. In Alberta, an economic evaluation of gas conservation must be presented when applying for permit, and gas must automatically be conserved if NPV ≥ Cdn$ 55 000. Alberta is the only one of the three jurisdiction which also has a blanket threshold where conservation of gas is automatically required, namely when the GOR > 3000 m³/m³. Also in Alberta, conservation of gas is required if flare volume ≥ 900 m³/day per site and the flare is within 500 m of an existing residence and in such cases annual economic re-evaluation of conservation options have to be presented.

With respect to the flare boundary, in the UK flare consent is usually field-based, but several fields tied-in to common facilities/infrastructure might receive a single consent, if their total flaring volume ≤ 40 tonnes/day, and if operator and licensees are the same for all the fields or if they agreed to share one consent. For both Texas and Alberta the boundary may be more site or facility specific.

Possible implications for flare regulations in Egypt

Many oil producing countries have adopted elements of “best practise flare regulations” as presented above, and the attention of flaring internationally implies that more countries consider regulatory reforms. As noted in Section 5.2, Egypt has little explicit flare regulation, but can benefit from taking steps which sets clearer rules and procedures for addressing the problem.

It is recommended that a process is started to consider more specific flare regulations. Based on the review above and other empirical results of this Study, it is thought relevant to consider the following elements of flare regulations:

- **Setting criteria and specific rules for flare permits and/or threshold for flare prohibition.** This includes the selection of variables to define thresholds, definition of routine flaring versus flaring justified for operational reasons, setting of administrative and/or physical boundaries for the regulations (e.g. license/field/well(s)). Since most licenses in Egypt have relatively low oil production and flare volumes, a threshold based on flaring per unit of time seems more relevant than applying a threshold related to the share of associated production being flared.
• Setting rules and procedures for exemptions to be granted. The technical and economic conditions for associated gas utilization may vary greatly by field/concession and such factors must be considered when/if granting flare permits. A techno-economic analysis in a predetermined format may be required. The empirical analysis presented in Section 6.3 of this report suggests that it is possible to come up with some indicative benchmarks for a decision making process of granting a flare permit. Under all circumstances, there probably would have to be communication/negotiations between the operator and regulator on these issues, and flexibility in enforcement by the regulator. This already exists today, but the point here is to bring it into a more formalized structure.

• Setting specific requirements and procedures for monitoring, reporting and verification (MRV) of flaring. Flare regulation requires a more comprehensive MRV system than what is currently in place. Requirement for direct measurement of gas streams to flares is needed, including also methods and technologies to be applied and specific reporting instructions. Procedures for verification of data (possible third party verifications or spot checks) may also be considered. Although the focus of flare regulations primarily is on routine flaring, rules may also be established to report on events of intermittent flaring and other flaring having operational causes.

An important condition for an efficient and cost-effective flare regulation is a well-functioning regulator. Clearly, EGPC has much of the capabilities required, particularly related to the assessment of technical and economic challenges of flare reduction investments. EGPC is also intimately involved in the planning process of new production developments where gas utilization options are being considered. This implies that there may be less of an “information and knowledge bias” than what often is the case between an operator and the regulator. Nevertheless, it is a problem that EGPC currently has the mandate to take care of both commercial and regulatory functions of oil and gas licenses. Such dual functions are no longer common practice internationally; it conflicts with what is broadly considered as “best practice regulations”. It is noted that regulatory reforms, including institutional changes, are under development for the gas sector in Egypt (see below). It should be considered to extending this to regulation of gas flaring.

Other policies

Other policies than specific flare regulations can also play an important role. The new Gas Law and the GRA have already been mentioned as means to improve framework conditions for associated gas utilization. Particularly if this includes reforms which lead to price formation based on market principles. This would improve the financial viability of associated gas utilization projects significantly as compared to the current situation. Empirical analysis of this Study shows that an increase in the gas price from 2.65 US$/MMBtu now often being offered for associated gas to 4 US$/MMBtu could improve economic return of gas flare reduction projects by more than 10 percentage points (see Section 6.3 for further details).

Associated gas utilization can also be incentivized through other changes in the legal and regulatory framework. Many countries give priority to deliveries of associated gas into gas infrastructure. From what is known about the new Gas Law it seems that third party access to transportation infrastructure is part of the reforms proposed, but it is unknown whether any preferential terms will apply and/or whether terms for supplies into processing will be improved.

Natural gas is an energy source with superior environmental qualities compared to coal and oil products. Use of associated gas magnifies these qualities since flaring is a pure resource waste. Currently this is not reflected in pricing policies or other economic incentives, unlike the high feed-in
tariffs being granted for supplies of power from wind and solar energy sources. Renewable feed-in tariffs are in the range 117 to 143 US$/MWh, which is substantially above the level being paid for sales of other power supplies to the grid by independent power supplies. Other than renewable power supplies are typically paid from 22 to 44 US$/MWh (17-35 P.T/kWh in Egyptian currency), as established by the “Electric utility and consumer protection regulatory agency”. Analysis in Section 6.3 below illustrates that on-site power generation projects, based on associated gas supplies, could have the economic return improved by up to 24 percentage points if power supplies were offered a feed-in tariff of 100US$/MWh rather than 44 US$/MWh.

6. Options for flare reduction

6.1 Overview of options and approaches and technologies suitable for Egypt

There are a number of technologies and approaches available for flare reduction efforts. Table 3 below lists 8 approaches for use of associated gas as standalone investments, or through larger investments schemes combining associated and non-associated gas supplies.

Table 3: Approaches and technologies for flare avoidance investments

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
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<tbody>
<tr>
<td>F1</td>
<td>Power for own use</td>
</tr>
<tr>
<td></td>
<td>Associated gas is captured and used for power and heat at the production site.</td>
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<tr>
<td>F2</td>
<td>Power for own use and delivery to a market</td>
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<tr>
<td></td>
<td>Includes the activity under F1 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.</td>
</tr>
<tr>
<td>F3</td>
<td>Gas delivery by pipeline</td>
</tr>
<tr>
<td></td>
<td>Gathering, pre-treatment and transportation of associated gas for export by pipeline for further processing and/or end use.</td>
</tr>
<tr>
<td>F4</td>
<td>Gas delivery by mobile equipment (CNG/LNG)</td>
</tr>
<tr>
<td></td>
<td>Treatment and transportation of the associated gas from the production site as compression (CNG) or liquefaction (LNG), normally by trucks or train.</td>
</tr>
<tr>
<td>F5</td>
<td>Small and medium size gas to liquids (GTL)</td>
</tr>
<tr>
<td></td>
<td>Small scale GTL technologies (GTL Fischer-Tropsch or GTL-methanol) under development for utilization of stranded associated gas at remote small and medium size fields.</td>
</tr>
<tr>
<td>F6</td>
<td>Reinjection of gas</td>
</tr>
<tr>
<td></td>
<td>Associated gas being reinjected for storage and/or enhanced oil recovery (EOR).</td>
</tr>
<tr>
<td>F7</td>
<td>Large scale gas processing and delivery by pipeline</td>
</tr>
<tr>
<td></td>
<td>Large investments not only involving associated gas and/or a green-field development including a broad set of investment in oil and gas processing facilities and transportation solutions.</td>
</tr>
<tr>
<td>F8</td>
<td>Large scale LNG/GTL/GTC</td>
</tr>
<tr>
<td></td>
<td>As with F7 above, for this category economy of scale is critical and projects under this category are 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.</td>
</tr>
</tbody>
</table>

Given the preponderance of small and medium size flare sites in Egypt, and an examination of site specific factors and related cost data, categories F1 to F4 of gas utilization/technology options are considered to be the most promising. This is because flare sites predominantly have gas volumes below 5 MMscfd.

Categories F5 to F8 are not necessarily unattractive in Egypt, but some key characteristics make them less important as part of a strategy to eliminate existing flares and avoid new flare sites to emerge:

- **F5: Small and medium size gas to liquids (Mini-GTL)**\(^{25}\), has increasingly attracted attention as associated gas utilization options particularly “stranded gas” in remote locations. It offers

\(^{25}\) Including both the traditional “Fischer-Tropsch” gas-to-liquids and “gas-to-chemicals” (see Chapter 3).
portable and scalable solutions. They have been demonstrated in pilot plants but have only to a very limited extent so far been deployed on a commercial basis and they cannot be characterized as mature technologies. The economic returns are sensitive to international oil prices and are unattractive at current price levels.

- **F6: Rejection of gas.** On a global scale this is by far the most common form of flare avoidance measure. There are no reliable data on the scale of re-injection of associated gas in Egypt, but it is clear that considerable quantities of associated gas production in the Gulf of Suez are being reinjected for the purpose of enhanced oil recovery. It is known that one or a few more projects are under planning in the same region while this option is not common in the Western Desert. Given that new sources of associated gas production generally will be small, and that reinjection for enhanced oil recovery normally requires a certain scale to be economic, they will rarely be an economic solution, at least as long as a flaring fine/penalty is not imposed.

- **F7 and F8: Large scale gas processing and delivery by pipeline and gas-to-liquids**
  These investment alternatives require large, stable and long-term supplies of gas, and associated gas supply sources in Egypt would only be able to contribute a very small part of the gas required and hence have no impact on investment decisions.

As part of this Study, four investment cases, covering the gas utilization categories F1 to F4, have been scrutinized. The purpose of the case studies has been to identify bankable flare reduction investments for possible co-financing from the EBRD, and further to examine more generically the opportunities for flare reduction projects in Egypt. The name and location of the cases are not revealed here, but a summary of findings from the case studies are presented below.

### 6.2 Summary of case studies

Of the four cases, three are small scale in terms of gas utilization and capital expenditures. One case has a larger gas volume (20 MMscfd) but modest capital expenditures because the investment being considered is a temporary solution until a larger and more permanent gas handling facility is in place.

<table>
<thead>
<tr>
<th>Case</th>
<th>Case – gas utilization option considered</th>
<th>Flaring (*)</th>
<th>CAPEX (**)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Pipeline transport (F3)</td>
<td>2.2 MMscf</td>
<td>20 million US$</td>
</tr>
<tr>
<td>2</td>
<td>NGL recovery and on-site power production (F1,F3)</td>
<td>1.1 MMscfd</td>
<td>4 million US$</td>
</tr>
<tr>
<td>3</td>
<td>CNG, pipeline transport and on-site power production (F2,F3,F4)</td>
<td>2.0 MMscfd</td>
<td>8 million US$</td>
</tr>
<tr>
<td>4</td>
<td>CNG as a temporary solution for market outlet (F4)</td>
<td>20 MMscfd</td>
<td>30 million US$</td>
</tr>
</tbody>
</table>

(*) average daily flaring over the economic lifetime of the projects (**) for the most advantageous solution

The first three cases are representative of several other potential investment cases in Egypt given the volume of gas flaring and the distance from gas infrastructure in question. The most important variables for the viability of business cases are, however, the associated gas production profile over time (i.e. decline rate) and the price being paid for the gas supplies.

26 Many acronyms are being used; from GTL and GTC to gas-to-fuels (GTF) and gas-to-gasoline (GTG). For simplicity, the most common term “GTL” will be used for all options covered in this report.
Both Case 2 and Case 3 have production wells with relatively steep decline rates, and the prospects for counteracting this with production from new wells are uncertain. This is a common feature of several of the licenses for which information has been made available as part of this Study. Case 1 also has uncertainty regarding future gas supplies and its off-shore location relatively far from the nearest GPP (>30 km) makes it unprofitable from a commercial perspective.

For all cases, a base case price assumption of 2.65 US$/MMBtu for sold gas is applied. As will be elaborated further in Section 6.3, an increase in the gas price will have major impacts on the profitability of the projects. For the first three cases a ten years economic lifetime of the investments has been applied and all economic results are pre-tax using a real discount rate of 7%

**Case 1: Pipeline transport**

The field has been in operation and has flared gas for some 10 years and it is assumed that 2.2 MMscfd can be recovered (on average) over a 10 years period from two separate offshore locations. Initially four gas utilization options were considered: i) increased use as fuel on-site ii) use of associated gas as lift-gas iii) gas re-injection for EOR v) export if gas by pipeline to a GPP more than 30 km from the production facilities.

Only the last of these alternatives was considered to be technically feasible. The results of the techno-economic analysis are presented below.

<table>
<thead>
<tr>
<th>Description</th>
<th>APG MMscfd</th>
<th>CAPEX mill USD</th>
<th>NPV mill USD</th>
<th>IRR %</th>
<th>ER ktCO2/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas export</td>
<td>2.2</td>
<td>20.2</td>
<td>-4.1</td>
<td>2</td>
<td>40-50</td>
</tr>
</tbody>
</table>

The economic returns of this investment are not considered commercially attractive under base case assumptions. Given the sizeable environmental benefits and the indication of an unquantified upside potential associated with a gas-condensate reserves within the concession, further assessments could be justified and should focus on the following three key parameters to achieve a more robust techno-economic assessment:

- The profile of excess associated gas that can be recovered and sold over the next 15-20 years. Both the annual amount of gas and the expected duration of oil production (lifetime of the project) have a large impact on project economics.
- The long-term price that can be negotiated for delivery of the associated gas to the GPP (the gas quality is not known by Carbon Limits, and the Concession agreement does not include a price for gas)
- The cost of pipe procurement and laying of offshore pipelines (pipeline related costs represent 82% of the estimated CAPEX)

In addition, it could be explored whether it is possible to monetize the GHG emission reductions from the flare elimination.

**Case 2: NGL recovery and on-site power production**

The concession consists of more than ten development leases and currently produces approximately 6,500 bbl/d of crude oil, and about 1.1 MMscfd of associated gas. Most of the associated gas is flared or vented at the different production facilities within the concession. Associated gas is currently used as fuel gas in a pilot gas generator at one oil well, and the company is considering expanding the use of associated gas as fuel for power generation.
The analysis has been conducted in two steps: (1) establish assumptions regarding production, flaring and energy demand at different locations within the concession and (2) conduct economic analysis of the selected gas utilization options based on the projections of future operations resulting from step one.

Due to very limited volumes of gas at many of the production facilities, only four production sites with the largest projected volumes of associated gas production are, from an economic perspective, relevant to include. As a result, the case study focused on recovery of gas from the other three production sites located in close proximity to each other. A total of five alternative utilization options were studied. The results of the techno-economic analysis under base case assumptions are summarized below:

Two of the options are financially attractive by a clear margin:

- Option 1, i.e. recovering a portion of the associated gas to produce electricity in rented gas driven gen. sets that would substitute diesel consumption to meet local electricity loads, represents the most economically attractive option.

- Option 4, i.e. combining NGL recovery and sale of the heavier components in the associated gas (C5+) and using the residual (treated) gas to produce electricity in rented gas driven gen. sets to meet local electricity loads, represents the most interesting option in terms of maximizing resource preservation and minimizing associated gas flaring. While this option can increase amount of energy recovered for productive purposes it should be noted that the economic attractiveness of NGL recovery is sensitive to market conditions (e.g. condensate net-back and CAPEX) and the NGL content of the gas.

In consideration of the uncertainties related to some of the base assumptions applied in the techno-economic analysis, it is recommended as part of the case study to proceed with step-wise process with development of investment plans.

**Case 3: CNG, pipeline transport and on-site power production (F2, F3, F4)**

The field currently flares around 2 MMscfd of associated petroleum gas. The base case assumption is a declining production profile, although the operator’s ambition is to maintain stable production. Four different options for utilizing the gas currently flared have been analysed:

- i) Raw gas exports – Tie-in to the gas trunk-line 5 km away.
- ii) Raw gas exports – CNG transports to GPP 65 km away.
- iii) On-site power production for export to a network 15 km away - generators purchased.
- iv) On-site power production for export to a network 15 km away – generators rented.

The economics of the raw gas cases as shown in the table below assumes that the gas is remunerated at a price of 2.65 US$/MMBtu.
Further, it is assumed that the gas trunk-line has the capacity and other conditions for taking gas with the specifications of the raw gas from the production site, and similarly, that the GPP can take the gas with specified qualities. The results are highly sensitive to gas price, gas production profile and pipeline costs which all are considered uncertain. A gas price of 4 US$/MMBtu would increase the internal rate of return (IRR) by about 17 percentage points. A stable rather than a declining production profile over the next 10 years would improve the IRR by 6 to 7 percentage points. With a pipeline cost assumed to be 1 million US$ per kilometer, tie-in to the trunk-line is more attractive than CNG transportation. However, the technical feasibility of the tie-in option has not been assessed. It should also be noted that the CNG trucking option involves a number of technical and HSE risks that must be addressed.

The two local power generation alternatives show markedly different results, with the option of using rented generators being financially viable, while purchase of generators being less attractive.

<table>
<thead>
<tr>
<th>Description</th>
<th>APG MMscfd</th>
<th>CAPEX mill USD</th>
<th>NPV mill USD</th>
<th>IRR %</th>
<th>ER ktCO2/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Raw Gas exports – Tie-in to the gas trunk-line</td>
<td>2.1</td>
<td>6.8</td>
<td>3.7</td>
<td>24</td>
<td>36</td>
</tr>
<tr>
<td>2 Raw Gas exports – CNG export</td>
<td>8.3</td>
<td>9.5</td>
<td>19</td>
<td>19</td>
<td>34</td>
</tr>
</tbody>
</table>

The estimated costs of renting generators are based on another case study done under this EBRD Study. It is not fully clear whether the generators currently being available for rental in Egypt have specifications that would enable them to take the raw gas. The results are based on a power price of 44 USD/MWh (34.5 P.T/kWh in Egyptian currency), which is within the range of average energy costs given by the “Electric utility and consumer protection regulatory agency”. A lower or higher power price (both being possible) would greatly impact the economics of local power generation cases. It should be noted that feed-in tariffs for renewables are at about 100 US$/MWh. As with the raw gas export cases, stable production, rather than declining, would improve the IRR by 6 to 7 percentage points.

**Case 4: CNG as a temporary solution for market outlet (F4)**

Condensate production at the field is held back due to lack of a gas solution which would only be available after 24 months. Flaring of the gas during this period is not allowed. An analysis was therefore conducted whether temporary gas utilization could be found in order to facilitate early monetization of the condensate. CNG and small-scale GTL/LNG are all technically relevant, but GTL/LNG solutions would take considerable time to deploy (>24 months), and are primarily suitable for long-term developments with stable feed of lean gas. It is only trucking of “rich CNG” which under the prevailing conditions comes close to be of commercial interest. Still, 24 months of operation for the temporary solution is much too short to make it financially viable. At an assumed condensate net-back price of 50 USD/bbl and a gas price of 2.65 US$/MMBtu, more than 35 months of economic lifetime would be required, or alternatively a gas price of 7.5 US$/MMBtu over a period of 24 months would give the investment an internal rate of return of 7%.

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6.3 The economics of small and medium size flare reduction projects

Taking empirical data from these cases and other information on the flare situation in Egypt, as compiled in this Study, into consideration, this section presents a broader analysis of the relative merits of bringing gas to markets by pipeline or as CNG, and further, analyses the merit of expanding local power production to include exports of power to the grid.

The suitability and attractiveness of different options will depend on a number of factors, e.g.:

- a) the volume of gas that can be recovered and utilized over time,
- b) the share of natural gas liquids in the associated gas,
- c) the share of impurities such as H₂O, H₂S and CO₂,
- d) gas pressure, which impact on the cost of gas gathering, transport and processing,
- e) distance to existing infrastructure or markets.

The production profile is particularly important. As noted previously in this report, future challenges with flare reduction will primarily be to spur investments in gas utilization for medium and small scale projects with prevailing economic and non-economic barriers. Steep decline rates, particularly for small and medium size fields, call for technologies that are scalable and portable and which can be put in place with little lead time.

Assumptions

Three generic production profiles with a common decline rate of 15% and a peak production rate of 1 MMscfd, 5 MMscfd and 10 MMscfd respectively have been used for the analysis\(^\text{28}\). The recoverable gas is assumed to have an energy content of 1,100 BTU/SCF and be free of H₂S and CO₂\(^\text{29}\). Further, it is assumed that the gas can be recovered at a single point at low pressure. This

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\(^{28}\) Real investment cases vary significantly with respect to both recoverable volumes and decline rates. In Egypt there are several sites flaring substantially less than 1 MMscfd or having >15% annual decline rate (handling production from a few wells only), as well as sites with substantial volumes and relatively sustained production.

\(^{29}\) For real investment cases, presence of impurities would increase the costs of recovery for all options, and high content of CO₂ could substantially reduce the amount of recoverable energy.
implies that costs associated with gathering gas flared at different well pads within a concession for recovery through common infrastructure are not considered in the analysis.

The main assumptions used for the economic analysis are presented in Table 5, including base case cost assumptions for the pipeline, CNG and power options. Ranges are presented for distances to market ranging from 5 km to 200 km. It should be noted that the pipeline and CNG options do not comprise processing of the gas beyond gas conditioning (dew point control and partial extraction of NGLs and heavier compounds) to facilitate transportation to a gathering system or directly to a gas processing plant.

Table 5: Main assumptions used for the analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Assumptions:</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Common assumptions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project lifetime</td>
<td>years</td>
<td>10</td>
</tr>
<tr>
<td>Discount rate (real terms)</td>
<td>%</td>
<td>10 %</td>
</tr>
<tr>
<td>Gas sales price</td>
<td>US$/MMBTU</td>
<td>2.65</td>
</tr>
<tr>
<td>Power sales price</td>
<td>US$/MWh</td>
<td>44</td>
</tr>
<tr>
<td><strong>Pipeline option</strong></td>
<td>1 MMSCFD</td>
<td>5 MMSCFD</td>
</tr>
<tr>
<td>Pre-treatment, incl. (re-)compression</td>
<td>MUS$</td>
<td>2-3</td>
</tr>
<tr>
<td>Total pipeline cost (onshore)</td>
<td>MUS$/km</td>
<td>0.4</td>
</tr>
<tr>
<td>OPEX - Pre-treatment, conditioning and compression O&amp;M</td>
<td>% of CAPEX</td>
<td>7.5%</td>
</tr>
<tr>
<td><strong>CNG option</strong></td>
<td>1 MMSCFD</td>
<td>5 MMSCFD</td>
</tr>
<tr>
<td>Pre-treatment, incl. compression</td>
<td>MUS$</td>
<td>2</td>
</tr>
<tr>
<td>CNG costs - trucks and loading</td>
<td>MUS$</td>
<td>2-3</td>
</tr>
<tr>
<td>OPEX - Pre-treatment, conditioning and compression O&amp;M</td>
<td>% of CAPEX</td>
<td>7.5%</td>
</tr>
<tr>
<td><strong>Power option</strong></td>
<td>1 MMSCFD</td>
<td>5 MMSCFD</td>
</tr>
<tr>
<td>APG gen-set</td>
<td>MUS$/MW</td>
<td>1.5</td>
</tr>
<tr>
<td>Efficiency</td>
<td>%</td>
<td>30%</td>
</tr>
<tr>
<td>Balance of Plant</td>
<td>MUS$</td>
<td>1</td>
</tr>
<tr>
<td>Power lines</td>
<td>MUS$/km</td>
<td>0.25</td>
</tr>
<tr>
<td>OPEX – Excl. fuel</td>
<td>MUS$/yr</td>
<td>0.2 - 0.4</td>
</tr>
</tbody>
</table>

Box A summarizes the key cash flow items calculated for four hypothetical investment cases using the assumptions presented in Table 5 above.
BOX A – CAPEX, OPEX AND REVENUES FOR SELECTED ILLUSTRATIVE CASES

The CAPEX, OPEX and revenues for the three technology options analysed are presented below for the 1 MMscfd and 10 MMscfd production cases with distances to relevant markets of 5 and 200 km using the assumptions presented in Table 5. The two gas-to-market options and the gas-to-power option are shown next to each other, but in terms of comparisons it should be noted that the distances to the respective markets for gas and power are generally not identical.

Figure A.1 – Cash flow items calculated based on main assumptions and case examples (in million US$)

<table>
<thead>
<tr>
<th>Gas utilization option</th>
<th>1 MMscfd case</th>
<th>10 MMscfd case</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Distance to market</td>
<td>5 km</td>
</tr>
<tr>
<td></td>
<td>Total CAPEX (no residual values assumed after 10 years of operations)</td>
<td></td>
</tr>
<tr>
<td>Pipeline</td>
<td>3,7</td>
<td>75,0</td>
</tr>
<tr>
<td>CNG</td>
<td>4,3</td>
<td>5,4</td>
</tr>
<tr>
<td>Power</td>
<td>8,3</td>
<td>57,0</td>
</tr>
<tr>
<td></td>
<td>Total OPEX, discounted over 10 years of operations</td>
<td></td>
</tr>
<tr>
<td>Pipeline</td>
<td>0,5</td>
<td>1,9</td>
</tr>
<tr>
<td>CNG</td>
<td>0,9</td>
<td>1,3</td>
</tr>
<tr>
<td>Power</td>
<td>0,9</td>
<td>1,4</td>
</tr>
<tr>
<td></td>
<td>Total revenues, discounted over 10 years of operations</td>
<td></td>
</tr>
<tr>
<td>Pipeline</td>
<td>5,6</td>
<td>5,1</td>
</tr>
<tr>
<td>CNG</td>
<td>5,5</td>
<td>5,5</td>
</tr>
<tr>
<td>Power</td>
<td>5,7</td>
<td>5,7</td>
</tr>
<tr>
<td></td>
<td>Pre-tax project IRR, applying base case assumptions</td>
<td></td>
</tr>
<tr>
<td>Pipeline</td>
<td>21 %</td>
<td>-37 %</td>
</tr>
<tr>
<td>CNG</td>
<td>12 %</td>
<td>3 %</td>
</tr>
<tr>
<td>Power</td>
<td>-4 %</td>
<td>-32 %</td>
</tr>
</tbody>
</table>

The next sections present the key findings of the analysis with respect to how different recoverable volumes, distances to market outlets and market prices affect the relative attractiveness of the three gas utilization options considered. Changes in relative attractiveness are analysed in terms of absolute change in the Internal Rate of Return (IRR) for key sensitivities.

Gas-to-market

For the two options considered for transportation of gas, Figure 13 illustrates the preferred option based on comparisons of their internal rate of return (IRR) for different combinations of recoverable volumes and distance to market.

Pipeline transportation is suitable for short distances and larger volumes. For smaller volumes located far from the market, the CNG option is generally favourable. Under base case assumptions, the
threshold is approximately 15 km distance for the 1 MMscfd case, increasing to 35-40 km for the 10 MMscfd case. The analysis does not take into account the value of mobility/terminal value associated with the CNG option; a large share of the CNG investment is related to trucks, which can be used elsewhere when production declines. Once a market for CNG trucks is established or renting options are available, threshold distances would reduce.

Figure 13: Preferred transport option based on IRR (gas price 2.65 US$/MMBtu)

Focusing on factors that determine the economic return, Figure 14 illustrates how the two options to bring gas to the market are sensitive to distance to market and recoverable gas volumes.

Figure 14a: Average absolute change in profitability (ΔIRR) depending on the distance to markets

Figure 14b: Average absolute change in profitability (ΔIRR) depending on the recoverable volume

As is shown in Figure 14a, the profitability of the pipeline option is strongly related to the distance to a suitable market access point (e.g. existing pipelines, GPPs or gas-fired power plants). Larger distances increase substantially the capital expenditure (mileage of gas pipelines and extra compression to balance pressure drop). CNG on the other hand is a more scalable technology option, but long distance CNG transport has other challenges (HSE risks, complex logistics).

In Figure 14b, it is shown that the profitability of the pipeline option is strongly correlated with recoverable gas volumes. The operating costs of CNG are strongly linked to the recovery level.

Figure 15 shows that the incremental Internal Rate of Return (IRR) for both the pipeline and CNG options are strongly correlated with the gas price. For each 1 US$/MMBtu increase in the gas price, the analysis shows a 10% absolute increase in the IRR for the CNG option, and slightly less for the pipeline option.
Gas-to-power

Production of power on-site to meet demand for local loads using associated gas as a fuel can be attractive compared to diesel-based power generation when gas supply and electricity demand exceeds the capacity of commercial scale units. The use of associated gas for power generation on-site is increasing in Egypt, with several projects under consideration or implementation. Scalable, mobile solutions and renting opportunities increase the attractiveness of using associated gas for local power generation. Except for extreme cases with very limited gas-to-oil-ratios (GOR) and/or substantial energy requirements to sustain production (e.g. use of ESPs), associated gas production far exceeds the fuel gas demand to meet local loads. If off-site consumers of electricity are located close to the flare site, increasing the scale of local power generation facilities to accommodate for utilization of most or all of the produced associated gas and selling surplus electricity through relatively short-distance power cables (e.g. connecting to the grid) can be an attractive option compared to long-distance gas export to a suitable market outlet. This solution to eliminate flaring is hereafter referred to as the “power option”. There are a number of considerations that have to be made, most importantly the ability of the off-taker to handle a relatively variable source of base-load power supply.

Figure 16 illustrates how the power option is sensitive to distance to off-takers and recoverable fuel gas volumes. Power is close to CNG in terms of scalability, as the major costs are related to investments in power gen-sets and power lines are cheaper than gas pipelines, especially for larger distances and capacities.

Figure 15: Average absolute change in IRR based on increases in the base case gas price

![Figure 15: Average absolute change in IRR based on increases in the base case gas price](image)

Figure 16a: Absolute change in profitability (ΔIRR) depending on the distance to markets

![Figure 16a: Absolute change in profitability (ΔIRR) depending on the distance to markets](image)

Figure 16b: Absolute change in profitability (ΔIRR) depending on the recoverable volume

![Figure 16b: Absolute change in profitability (ΔIRR) depending on the recoverable volume](image)
While proximity to a market and scale are important, the key factor is the power tariff as shown in Figure 17. An increase in power tariff of 10 US$/MWh could increase IRR by >5% in absolute terms.

Figure 17: Absolute change in IRR based on increases in the base case power tariff

6.4 Summary of findings

The main findings from the empirical analysis, including the real investment cases assessed, are:

- At current price level for gas/power supplies, most small projects (<1 MScf/d) are uneconomic.
- Production of power on-site to meet demand for local loads is typically attractive under diesel prices above 300 US$/ton where both recoverable gas volumes and power demand exceed the capacity of commercial scale units (typically >0.3 MW load and >75 Mscf/d fuel gas available). Scalable, mobile solutions and renting opportunities increase the attractiveness of using associated gas for local power generation. Disperse well pads with centralized oil treatment (and gas separation) facilities reduce the commercial attractiveness.
- Among the solutions capable of eliminating routine flaring (normally not the case for on-site use for power), only pipeline projects can be economic at current price levels, but then recoverable gas volumes must be medium or large in scale (≥ 5 Mscf/d) and distances modest.
- For small-scale flare sites (≤1 MScf/d) located more than 10-15 km from the gas market, establishment of a virtual pipeline based on CNG trucks is attractive compared to a conventional pipeline export solution. With higher gas prices, the attractiveness of the CNG option increases further compared to the pipeline option (it requires less up-front investments for distances above 5 km).
- For flare sites with gas production in excess of what is required to satisfy on-site energy needs, export of surplus power to the grid requires higher tariff than offered today to be commercially attractive. If power deliveries were paid at 100 US$/MWh (in the range of the current feed-in tariff for renewables), the threshold distance to the grid access point in order to have a commercially interesting case is estimated at 40 km with 1 MScf/d fuel gas available.
- Gathering of gas supplies from multiple smaller sources can help justify processing and separate marketing of natural gas liquids. The incentive for small-scale processing is limited under current market prices for natural gas liquids.
7. Capital requirements for flare elimination

7.1 Zero Routine Flaring by 2030 Initiative

The initiative for Zero Routine Flaring by 2030 launched in April of 2015 has not (yet) been endorsed by the Government of Egypt, while three international oil companies active in Egypt have endorsed it (BP, ENI and Shell). The title of the initiative indicates an explicit target of elimination of all routine flaring by 2030, but that is not the case. The text from launch of the initiative states that existing flares should be eliminated only to the extent that economically viable solutions can be found, while new oil fields should be operated “according to plans that incorporate sustainable utilization or conservation of the field’s associated gas without routine flaring”\(^{30}\).

The net costs of meeting the objectives of a zero routine flaring target therefore depend very much on the size and location of new oil and associated gas production. If new production, for a large part, is at remote locations with relatively small and dispersed oil wells, then the net costs can become relatively high. However, as shown in Chapter 6, the economics of the investments are highly sensitive to the prices being offered to delivered gas and power.

7.2 Analytical approach and assumptions

As part of this Study, there was no available data in order to make an overall estimate of the net costs of achieving a zero routine flaring target. However, a rough estimate has been made of required capital expenditures (CAPEX) of the more ambitious target of reaching zero routine flaring in Egypt by 2020, and by a policy of preventing any routine flaring to re-emerge from 2020 to 2030. It is assumed that all routine flaring is eliminated, independent of the economic viability of the investment. The results are summarized in Figure 18\(^{31}\).

These estimates are highly sensitive to the assumptions that are made about new oil production and the decline rate at existing fields. The decline rate is assumed to remain constant at 15% per annum, while the average gas-to-oil ratio of new developments is estimated at 14.2 m\(^3\)/bbl. Capital expenditures for the different investment categories and the chosen gas utilization options are in line with the data and analysis presented in Chapter 6.3 above. However, there is substantial uncertainty associated with making generic estimates; the flare sites analysed as part of this study have capital requirements ranging from 300 to more than 2,000 US$ per MCM/yr installed capacity to fully eliminate routine flaring.

For the purpose of the estimates made in this analysis, certain assumptions have been used regarding the split of investments on the three broad categories mentioned above:

- The pipeline solution dominates for elimination of existing flares until 2020, because many of the sites are medium and (relatively) large in size.
- Avoiding routine flaring from existing sites is assumed to have an average cost of 1,350 US$ per MCM/year, reflecting the higher cost associated with solutions comprising processing and power generation, considered applicable for some of the existing flare sites.


\(^{31}\) The estimates are based on both international costs for machinery and equipment and relevant costs for Egypt based on cases examined as part of this Study. The estimates are uncertain and qualitative by nature.
Avoiding routine flaring from new production sites is assumed to have an average cost of 1,000 US$ per MCM/year. This estimate is of course highly sensitive to the size and location of new production sites and the relative attractiveness of different technology options, some requiring higher capital expenditures than others to reach more attractive markets.

### 7.3 Results

As shown in Figure 18, it is estimated that elimination of flares existing in 2015 will have implied capital expenditures by 2020 of 2.0 billion US$. Investments must be undertaken in infrastructure capacity that is able to recover 1.5 BCM of gas. Expenditures in order to avoid routine flaring from new sites depend on the development in new oil production. If oil production stays constant at 0.7 million barrels/day to 2020, total capital expenditures to avoid new flaring for the 2015 to 2020 period are estimated to be 2.1 billion US$. Based on the decline and GOR assumptions used, additional infrastructure must have an installed capacity of 2.1 BCM to avoid flaring from new developments. Keeping routine flaring at zero from 2020 to 2030 is estimated to require 3.7 billion US$ in capital expenditures, under the assumption of constant oil production at 0.70 million barrels/day (installed capacity of 3.7 BCM required). A decline in oil production would lower the CAPEX needs for flare avoidance, as illustrated in Figure 18.

*Figure 18: Estimated capital requirements to achieve zero routine flaring*

The analysis here illustrates the importance of preventing flares from new production in order to achieve zero flaring. As indicated in Chapter 3 above, there are probably underway some important investments related to existing flares in 2015. This further emphasizes that the focus will be to identify at an early stage and find solutions for new flares that might emerge as part of new oil production. By delaying these investments, and hence losing valuable gas to flaring during early phases of the project lifetime, the economics of the gas utilization is often deteriorated significantly.
8. The potential role of carbon finance and climate policies

8.1 Flare reduction in the context of climate policies

Flare reduction in the order of 1.5 BCM/yr, referred to in this Study as the current level of routine flaring, translates to about 2% of Egypt's greenhouse gas emissions. Other sources of greenhouse gas emissions are more important, but flare reduction still deserves attention in the context of climate policy, for two reasons:

- Flare reduction offers several co-benefits in addition to climate change mitigation. Local environmental improvements can be substantial, though they are often not well documented, and economic and social benefits from making productive use of a previously wasted resource are potentially significant. The latter is particularly important in light of the precarious state of domestic energy supplies (e.g. power shortage) and the financial burden of energy imports.

- Costs are low for a large part of flare reduction projects and those that are not economic can often be made viable through changes in policies and regulations, as pointed out above, and through targeted economic incentives.

Egypt has already started to consider policy measures for flare reduction in the context of climate policy. A draft document outlining so-called Nationally Appropriate Mitigation Actions (NAMAs) have been prepared, of which one set of actions is targeted at the oil and gas sector and flare reductions.

Further, emission reductions from flaring and venting of gas were mentioned as mitigation measures in the Egyptian Intended Nationally Determined Contributions (INDC) submitted to the United Nations Framework Convention on Climate Change (UNFCCC) ahead of its annual meeting in Paris (COP21) in December 2015. The INDC document notes that the costs of addressing adequate climate change adaptation and mitigation in Egypt are estimated to be 73 billion US$ for the period 2020 to 2030\(^{32}\).

8.2 The potential role of carbon and climate finance\(^{33}\)

During more than 20 years history, a very important part of the UNFCCC process has been the financing of climate change adaptation and mitigation projects and programs. Transfer of funds from developed to developing countries is stated in Article 4 of the UNFCCC and was made explicit with a specific amount mentioned in the Copenhagen Accord of 2009\(^{34}\). The Paris Agreement\(^{35}\) contains important framework conditions for future climate finance and cooperation between countries on mitigation which may open new opportunities for flare reduction projects and programs.

In the past, the Clean Development Mechanism (CDM) of the Kyoto Protocol has been the principal vehicle for co-financing of GHG mitigation in developing countries. The CDM was a very effective

\(^{32}\) http://www4.unfccc.int/submissions/INDC/Published%20Documents/Egypt/1/Egyptian%20INDC.pdf

\(^{33}\) The term climate finance does not have a precise definition, but is typically understood as being “Capital flows directed towards low-carbon and climate-resilience development interventions with direct or indirect greenhouse gas mitigation or adaptation benefits”. A common definition of carbon finance is “Resources provided to a project or program in exchange for ownership to certified/verified greenhouse gas (GHG) emission reductions” (“carbon credits” for short). This chapter deals primarily with carbon finance.

\(^{34}\) The Accord set a “goal” for the world to raise $100 billion per year by 2020, from “a wide variety of sources”, to help developing countries cut carbon emissions (mitigation). Further, it was agreed to establish the Green Climate Fund as an operating entity of the financial mechanism, “to support projects, programme, policies and other activities in developing countries related to mitigation.”

\(^{35}\) http://unfccc.int/resource/docs/2015/cop21/eng/09r01.pdf
mechanism for fund provision until the carbon price collapsed in 2012. In total 7,500 projects were registered and the total amount invested in CDM projects is estimated to have been 400 billion US$ and 1,500 million tons CO2 emissions reductions have been achieved.

Compared to the contribution of flaring to global emissions of greenhouse gases, flare reduction projects have been underrepresented in the CDM. There are several reasons for this, including lack of awareness and knowledge about the CDM in companies, and uncertainty about the scale of revenues from the mechanism. The most important barriers, however, seem to have been the amount of work required in order to get projects approved and registered under the CDM. Rules and procedures are generally perceived as bureaucratic and burdensome, and this often hits flare reduction projects harder than many other project categories because investments in gas capture and utilization often are technically complex. Development of CDM methodologies to cover new types of mitigation projects has also been time and resource demanding and to a large degree left to potential project developers (bottom-up approach). The result has been that existing CDM methodologies only cover a few of the potential gas utilization options typically considered to reduce flaring. Among the gas utilization options currently covered by an approved CDM methodology, only pipeline export with or without processing of the gas has been applied by project developers to any significant degree.

In order to reduce such barriers, this Study has therefore included the task of finding ways to improve the methods by which flare reduction projects can be scrutinized and eventually be found eligible for financial support based on results in terms of GHG emissions reductions. The basis for this work is the general rules and procedures of the CDM, as well as the existing CDM methodologies approved by the UNFCCC.

Two alternative approaches to work on this have been explored:

- Develop a standardized baseline (SB), which can be based on an approved methodology or tool, or based on the “Guidelines for the establishment of sector specific standardized baselines”.
- Develop a CDM methodology for categories of flare reduction projects which currently are not covered by approved CDM methodologies.

An analysis of limitations with the existing CDM framework in relation to flare reduction projects has been undertaken. Suitability of flare reduction projects have been examined for four project categories (F1 to F4) presented in Chapter 6.1 as these are the most interesting for future flare reduction investment projects in Egypt.

**8.3 Project categories eligible for carbon finance**

As noted above many flare reduction projects are technically complex, and are for that reason not always amenable to the requirements for receiving carbon finance. This has first of all to do with complications in calculating emission reductions from flare reduction investments. Under the CDM the methodological and practical requirements for monitoring gas streams have been very demanding due to the complexities of many of these projects, and the stringency with which CDM methodologies have been reviewed and approved.

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36 This section draws heavily on the Briefing Note “Pilot Auction Facility for emissions reductions in the oil and gas sector” written by Carbon Limits for the World Bank, see http://www.worldbank.org/en/topic/climatechange/brief/pilot-auction-facility-methane-climate-mitigation
The result is that several project categories do not have applicable CDM methodologies, while available methodologies in other cases have proven to be too cumbersome and resource demanding to use. For this reason, it is important to consider carefully those categories of projects that seem most suitable for a climate finance mechanism, based on the following evaluation criteria:

**C1. Quantification and verification of results (MRV):** Sound standards and procedures should be available for calculating emissions reduction impacts. They should be based on existing monitoring, reporting and verification (MRV) standards and procedures, e.g. approved CDM methodologies or it should be a possibility to develop new MRV standards and procedures for them with reasonable effort and at reasonable costs. The standards should ensure environmental integrity but not be too onerous and resource demanding to follow.

**C2. Impacts on the economic returns on investments (economic impacts):** Payments for emissions reductions from project implementation should be significant enough to make a difference on the financial viability of a project. Typically climate finance is contingent on the greenhouse gas impacts being so significant that an investment shift from being financially unattractive to financially attractive after the emissions reductions are monetized.

**C3. Free-riders and perverse incentives (environmental integrity):** For the environmental integrity and efficiency in use of climate financial resources, it is important that the climate finance mechanism manages to target projects which are faced with implementation barriers, while the risk of admitting free-rider projects that would occur anyway is excluded or significantly reduced. The scheme should also not be encouraging less stringent emissions policies and regulations than otherwise would be the case, hence avoiding the so-called perverse incentives.

These criteria have been applied in assessing the climate finance suitability of the four project categories (F1 to F4) presented in Chapter 6.1 as being the most interesting for future flare reduction investment projects in Egypt. The assessment is summarized in Table 6.

### Table 6: Assessment of climate finance suitability for flare reduction project categories

<table>
<thead>
<tr>
<th>Category</th>
<th>MRV</th>
<th>Economic impacts</th>
<th>Additionality</th>
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<tbody>
<tr>
<td><strong>F1</strong> Power for own use</td>
<td>MRV: There are no CDM methodologies available that can be directly used. It is however not considered to be too resource demanding to develop a methodology ready to CDM approval based on the large number of CDM methodologies related to fuel switching and power generation. Economic impacts: In relative terms, the impacts will often be less than for the other categories because of the capital requirements associated with utilities. In absolute terms, the investments tend to be limited in size, and limited local power demand typically implies that a certain quantity of gas continues to be flared. Additionality: Use of associated gas for local power use is quite common, and additionality must probably be tested on a case-by-case basis.</td>
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<tr>
<td><strong>F2</strong> Power for own use and delivery to a market</td>
<td>MRV: Same as for F1 above Economic impacts: Larger impact than for F1 in absolute terms since there normally will be a market outlet for all power than can be produced. Potentially important impact on economic return (see Chapter Error! Reference source not found.) Additionality: Less of a common practice than F1. Economic return very sensitive to feed in tariff for power.</td>
<td></td>
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</tbody>
</table>
F3  Gas delivery by pipeline

MRV: Existing (approved) CDM methodology is available (AM0009 version 07), and MRV approach is straightforward. Substantial improvements in approach and ease of use in latest version compared to earlier versions of this methodology (in particular versions 01 to 03).

Economic impacts: Potentially important impact on economic return (see Chapter 6.2)

Additionality: A common investment alternative for associated gas utilization. Generally, economic return is project specific and standardization of additionality test would be difficult.

F4  Gas delivery by mobile equipment (CNG/LNG)

MRV: If the CNG is delivered to a GPP or pipeline then AM0009 applies. If the delivery is to a designated end user then AM0077 should be used. AM0077 has proven to be unusable (no CDM project has been approved under this methodology).

Economic impacts: Potentially important impact on economic return (see Chapter 6.2)

Additionality: Often the preferred option with small gas quantities and location far from gas infrastructure. Economic returns are often marginal. Generally, economic return is project specific, but there could be opportunities for standardization of additionality test.

In terms of limitations of the existing CDM framework, Table 6 shows that project categories F1 and F2 are not explicitly covered by any existing CDM methodology. Furthermore, a sub-category of F4 related to CNG delivery to individual end-users has proven to be unusable in practice due to MRV challenges. Delivery of gas in the form of LNG is also not properly covered for project category F4. Project category F3 is generally well covered, and there are numerous examples of project applications using the relevant CDM methodology AM0009.

The possibility of developing a SB based on AM0009 (covering project category F3), the only CDM methodology that has been applied to some extent, has been explored on the basis of the empirical analysis of this Study. The conclusion is that the great diversity in the characteristics of flare sites (primarily economically) makes this approach difficult given the current guidelines for SB. The determination of emission reductions is already very simple in AM0009 after a number of revisions to the original version of this methodology, and it is primarily demonstration of additionality which remains a challenge with AM0009.

Standardised baselines can be proposed based on an approved methodology or tool, or based on the “Guidelines for the establishment of sector specific standardized baselines”. There are two challenges with using the Guidelines for APG projects:

- First, the only measure in the guidelines that is appropriate would be "fuel and feed stock switch". Identifying additional technologies, however, requires an analysis from the point of view of the end user of a specific output (e.g. electricity, industrial heat). In other words, electricity generated by APG would be one of several possible sources of electricity for a given end user, and the standardized baseline analysis would rank all of those alternatives by their emissions intensity. Similarly, if APG is used for industrial process heat, then the SB analysis would rank all of the alternatives to deliver that heat (e.g. electric heating, other fossil fuels). If the APG is simply delivered to a pipeline system as for project category F3, however, it is not possible to identify who the end-users are, so this analysis of alternatives is not possible.

- Second, in additional to ranking technology options by emissions intensity, each option must be assigned a specific commercial attractiveness or barrier(s) to justify the selection of additional technology types. Because the commercial attractiveness of APG utilization varies over both space and time due to changes in fuel prices, distance to markets, and market development, it is very challenging to standardize additionality considerations for a given technology option and justify that proposed parameters for use in an SB are sufficient to address additionality concerns.
The alternative approach to revise an existing methodology or develop a new (traditional) CDM methodology to cover categories which are currently not covered by the existing CDM framework is considered to be of greater practical value to Egypt in the context of climate finance for flare reduction projects. Based on the situation in Egypt, it is considered that priority should be given to develop a CDM methodology that covers use of APG for local power generation, i.e. project categories F1 and F2. A draft revised methodology (AM0037) has been developed as part of this Study to accommodate project categories F1 and F2.

Approval of a methodology that covers project categories F1 and F2 would imply that all the categories that are most relevant for gas utilization investments in Egypt are covered by a CDM methodology. It is not for the purpose of CDM project development these methodologies will be used, but rather as a main reference and tool for other ways of seeking climate finance and/or documenting and verifying the climate change mitigation benefits of flare reduction projects. New potential sources of climate finance, other than the CDM, are reviewed below.

8.4 Sources of climate finance for flare reduction and the relevance of CDM methodologies

The only broadly recognized scheme of climate finance for flare reduction projects is the CDM. Rules, procedures and institutional structures are in place to approve projects according to sound principles of environmental integrity. The CDM is linked to the Kyoto Protocol which expires in 2020 and this together with the lack of demand for CDM credits implies that it currently has almost no role in terms of financial transfer to climate change mitigation projects.

This does not mean that the CDM is irrelevant for future schemes of climate finance; it is rather more likely that the CDM will be a major reference for new schemes. This can happen in two ways:

i) Projects approved and registered under the CDM may automatically be considered eligible to receive climate finance support under other schemes.

ii) Rules and procedures, and project/program methodologies developed under the CDM are adopted and/or used in modified (perhaps in a simplified) form under other climate finance schemes.

New schemes with climate finance relevant for flare reduction include:

1) *New Market-based Mechanism (NMM)* is discussed within the framework of the UNFCCC, but has not progressed much in the past few years. It may get more attention after the Paris Conference (COP21), probably early enough in order to be operational from the start of a Paris Agreement. This might be a UNFCCC managed mechanism with a project, program or sectoral scope.

2) *Nationally Appropriate Mitigation Actions (NAMAs)* are already a well-established system for reporting planned programs for mitigation in developing countries. Financial support (crediting) for such actions are being discussed. It might become part of NMM mentioned above or could be a separate mechanism. Since Egypt has already developed a NAMA for flaring the government could consider this further with the objective of attracting international climate finance for the planned actions. Arguably the first tangible initiative of NAMAs crediting was launched during the COP21 in Paris. Four European governments (Germany, Norway,

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37 Applying amendments to a pre-approved baseline methodology will involve fewer and easier procedures for CDM-EB approval than developing a new CDM methodology. Proposed revisions can be submitted to the UNFCCC using the “Form for submission of requests for revisions of approved methodologies to the Methodologies Panel”.
Sweden and Switzerland) have created the Transformative Carbon Asset Facility with an initial funding of 500 million US$ to finance large scale emission reduction programs in developing countries.

3) **Specific funds for oil and gas sector emission reduction projects.** The World Bank has several sectoral climate finance funds, and for one of these funds, the Pilot Auction Facility for Methane and Climate Change Mitigation (PAF)\(^{38}\), it is being considered to extend it to cover gas flaring (and methane emission reductions in the oil and gas sector). An early analysis of how such a fund might work for flaring is published and is now being considered by the World Bank and other stakeholders\(^{38}\).

4) **The EU Fuel Quality Directive** oblige suppliers of road transport fuels to reduce the greenhouse gas intensities of supplies by 6% from 2010 to 2020. This can be done by substituting petroleum products with LPG, CNG, biofuels and electricity. There is also an opportunity meet the requirements through financing of upstream oil and gas emission reductions outside the EU, which then would be an “offset mechanism” much like the CDM with a tradable emission reduction commodity called “upstream emission reductions” UERs. An important source of such offsets is believed to be flare reduction projects, and there are good reasons to believe that flare reduction in Egypt can monetize UERs. All relevant bodies of the EU have adopted the scheme, but detailed rules and procedures for it to be operational are still not completed by Member States. The generic ISO 14064-3 will form the basis for verification of UERs, but it is not yet clear whether any references will be made to CDM methodologies. It should be noted, however, that relevant CDM standards are more project specific and generally more stringent than ISO 14064-3. Therefore projects which passed under CDM requirements should automatically be eligible for the scheme of the EU Fuel Quality Directive.

5) **The Egyptian INDC** indicates that a national emissions trading scheme might be developed and this may eventually also be linked to a regional emissions trading scheme. Given the importance of the oil and gas sector in the region this may open the way for trade in emission units related to oil and gas sector operations and where flare reduction and methane emission reductions may be monetized through reduced purchase needs or sales of excess allowances. For such a system to work well there would obviously need to develop standards for monitoring, reporting and verification of emissions. Experiences through the CDM and specific methodologies may become important references for the design and operational rules and guidelines for such a system.

With the Paris Agreement now concluded the time is right for the Egyptian authorities to consider how they can possibly incorporate flare reductions into their Nationally Determined Contributions and further explore opportunities for attracting international climate co-financing for such efforts. This work should also incorporate work on how monitoring, reporting and verification (MRV) of flare reduction impacts should be handled and possibly be linked to new regulations (including MRV requirements) for flaring. The fact that Egypt may become a force in establishing a possible regional emissions trading scheme makes this even more relevant. The Paris Agreement is expected to enter into force in 2020, so there is some time to get prepared, but not a whole lot.