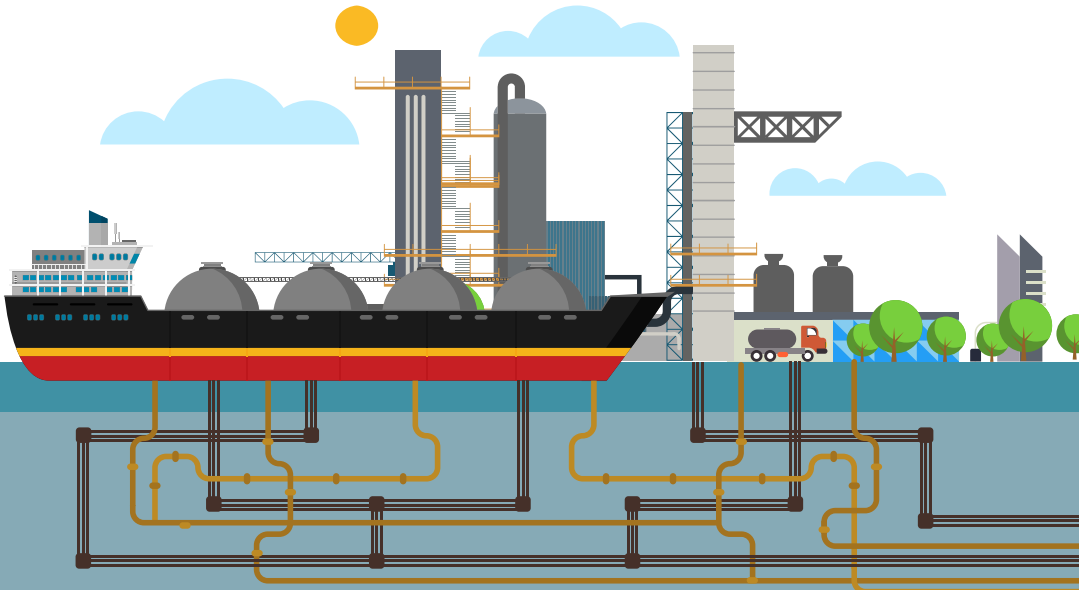


GAS INVESTMENT OUTLOOK

2019 - 2023



50%

y-o-y increase in petrochemicals investments
for 2019-2023 from our previous 2018-2022
outlook

USD BN

134

private sector share of planned petrochemicals
and other downstream gas projects





إبيكورب
APICORP

Gas Investment Outlook 2019 - 2023

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Key Messages

The entire MENA region witnessed a year-on-year (y-o-y) decline of USD 70 billion in the outlook for both committed and planned gas investments. This was driven by a combination of high global gas output, slowing regional demand and - in select countries - an inability to access finance.

However, investments in petrochemicals for 2019-2023 show a 50% y-o-y increase from our previous 2018-2022 outlook as the region enters the next wave of the supply integration and further monetisation of hydrocarbon production.

On planned investments, two-thirds of MENA countries will see lower investment in their upstream gas sectors. Upstream gas projects continue to be largely financed by NOCs, IOCs and some independents given the higher upfront risks associated with exploration activity.

More downstream, the wave of large petrochemical projects in the region and the few LNG terminals typically rely on a 70:30 - 80:20 debt/equity ratio. Margins however are being squeezed across the whole value chain.

The share of government investments for committed upstream gas projects currently stands at a little under 92%, compared to 61% for midstream and downstream projects and significantly less for petrochemicals at 29%.

Decrease in investments in gas value chain (-27%) raises concerns about future indigenous supplies given growing demand, from industry and increasing share of gas-fired power generation capacity. In many countries, the required investments largely depend on government's ability to pay cost-related [e.g. the Blended Price in Saudi Arabia] or market-related prices [e.g. linkage to Brent as in Egypt and Iraq].

Gas pricing directly affects the profitability and competitiveness of the different industries where it is used as a feedstock or fuel. In the specific case of Algeria, the country will have to address concerns over low upstream investments and access to needed technology for maturing fields.

The industrial sector accounts for roughly 30% of total Middle East gas consumption. The private sector's role is expected to increase given the growing share of planned petrochemicals and other downstream gas projects [USD 134 billion or 71%] in the overall gas value chain [vs. upstream and midstream].

LNG continues to benefit from the very low regional gas connectivity, with the latest regasification terminals added in the region, on track in Kuwait and the UAE. On the supply side, Qatar is moving ahead with upgrading its liquefaction capacity from 77 Mtpa to 126 Mtpa by 2027. Egypt is touting itself as a gas hub on the strength of robust regional demand, steady supplies and physical infrastructure with a relative edge over its neighbours, but key elements are still amiss.

Key Global Gas Trends

A record year for LNG FIDs and traded volumes, supply “glut” might not clear before mid-2020s

2019 will be remembered as a record year for LNG Final Investment Decisions (FIDs), which crossed the USD 50 billion threshold for the first time ever. This milestone was driven mainly by North American projects’ adoption of equity off-take marketing structures, and supported by the addition of the Rovuma LNG (Mozambique) and Arctic LNG-2 (Russia).

The share of natural gas in the energy mix has risen steadily. In 2018, gas accounted for approximately 23% of global primary energy con-

sumption. Over the same period, demand for gas grew by 4.6%, its highest jump since 2010, or about 45% of the total increase in primary energy consumption. This uptick is forecast to continue from 2019 to 2024 at an average rate of 1.6% annually as the build-up in global pipeline and LNG investments estimated at more than USD 200 billion continues into 2025.

In addition to supply possibly outpacing demand until 2023, uneasy trade wars and geopolitical tensions are further complicating matters. Rus-

Selected Gas Prices at Key Hubs



Source: S&P Global Platts

sia, which continues to defend its market share in Europe, delivered its first Yamal LNG cargo to China in July 2019, a mere five months after the United States' last LNG cargo arrived in China in February 2019. In December, Russia, along with China, also inaugurated the 38 billion cubic meters per annum (bcma) Power of Siberia pipeline. The USD 400 billion, 30-year contract, is the biggest ever for Gazprom.

Amidst the ongoing supply glut, there is a growing risk of projects getting crowded out. LNG prices are expected to remain under pressure until 2023 due to the abundance of spot LNG cargoes. Indeed, most global hubs and key indices have already witnessed drops in prices from 2018 to 2019, a trend expected to continue into 2020. For example, the annual average for the LNG Japan-Korea Marker (JKM), which stood over USD 10 per million british thermal unit (mmbtu) in 2018, dropped to less than USD 5/mmbtu in Sep 2019. Similarly, Europe's TTF (Title Transfer Facility) prices fell from approximately USD 7.5/mmbtu to less than USD 2.5/mmbtu over that same period, and the same applies to the United States' Henry Hub marker.

Oil price indexation is not going away yet. According to the International Gas Union (IGU)

USD BN
50+

LNG Final Investment Decisions
crossed this threshold for the first
time ever in 2019

survey, "oil price escalation" schemes are very slowly losing ground to gas-on-gas competition. This is due to the fact that the loss in LNG trade is partly offset by gains in pipeline trade and indigenous Chinese production. As such, the oil price escalation share declined by a quarter of a percentage in 2018.

Wholesale prices outside North America rebounded in 2017-2018 as oil prices and other commodities increased and spot markets tightened in Europe and Asia. In regulated markets such as MENA, prices continue to be reformed by regulators to reflect costs of supply or market dynamics.

Financing and investment trends in an era when NOCs are entering the portfolio player game

The share of short- and medium-term contracts has been hovering around 30%. US projects, which account for about one third of this year's FIDs, are using a wider variety of financing strategies and commercial schemes.

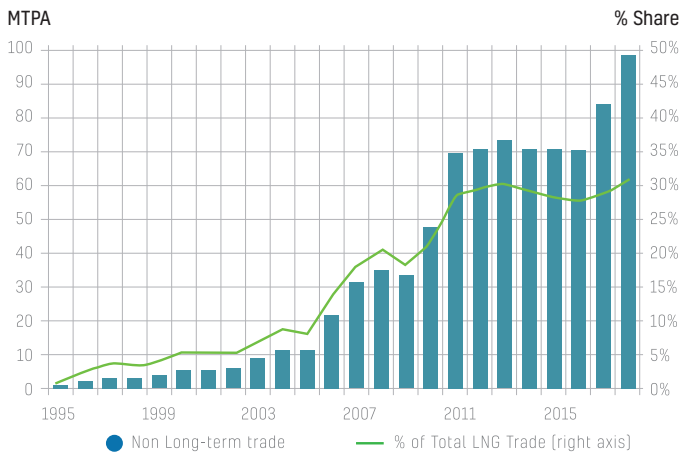
The financing strategies currently range from project financing (82:18 Debt/Equity ratio for Calcasieu Pass, 45:55 Debt/Equity ratio for Sabine Pass Train 6) to self-financing using own balance sheet (Golden Pass, 70% Qatar Petroleum 30% ExxonMobil).

As for commercial schemes, these range from long-term Supply Purchasing Agreements (SPAs) with third parties to affiliate marketing (the entire 15.6 Mtpa capacity of Golden Pass

was sold the project sponsors' marketing Joint Venture (JV)). The SPAs may utilise Henry Hub indexation and more traditional indexations (Brent, JKM, hybrid).

Apart from Qatar Petroleum which already has a large global portfolio, Saudi Aramco is the other MENA NOC looking into investment opportunities globally and in the US in particular. The signature of a Heads of Agreement (HOA) in May 2019 for Port Arthur LNG (Sempra) signals a first building block in Saudi Aramco's announced strategy to become a major LNG portfolio player through investments in various parts of the value chain. Under the yet-to-be-finalised HOA, Saudi Aramco would purchase 5 Mtpa and take a 25% equity in the project.

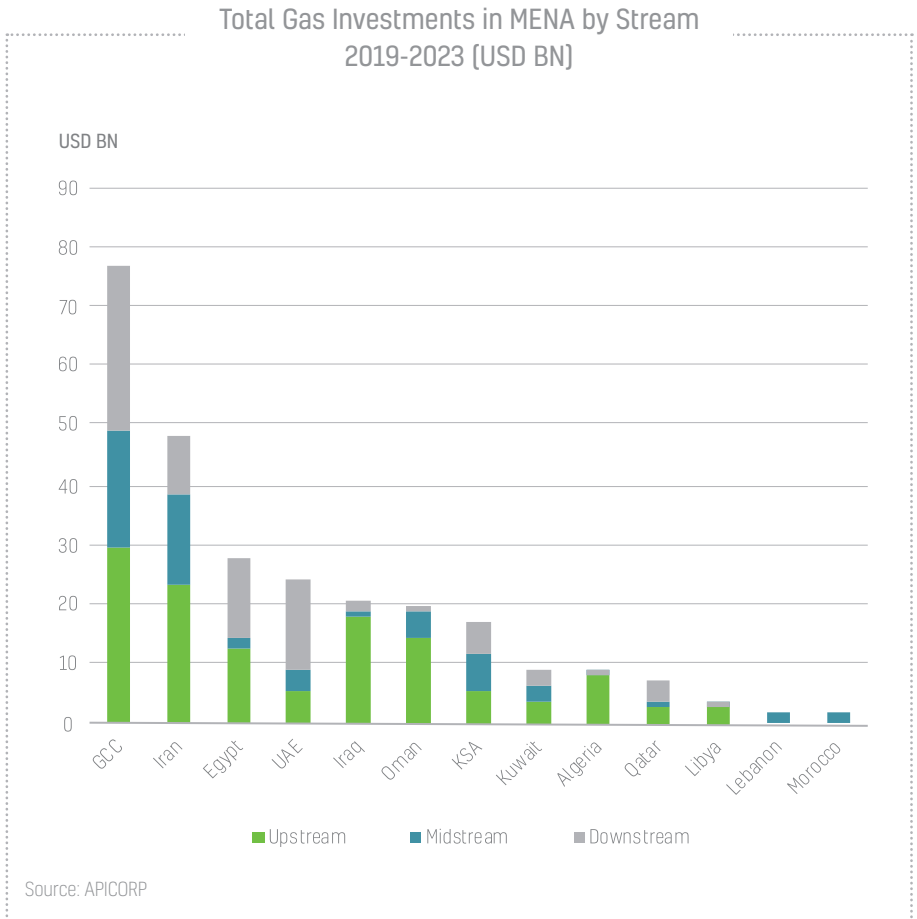
Non Long-term Trade vs % of Total LNG Trade



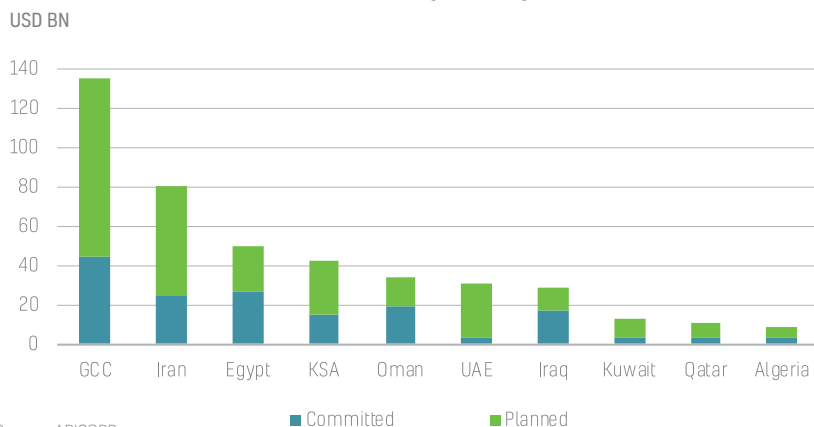
Sources: IHS Markit, IGU

Gas Investments in MENA

USD 70 billion [-27% y-o-y] decline for total [Planned & Committed] investments expected over the next five years



Total Investments for Gas and Petrochemicals 2019-2023 (USD BN)



Source: APICORP

While MENA Petrochemicals - Planned and Committed investments - for 2019-2023 show a 50% y-o-y increase from our previous 2018-2022 outlook:

The MENA region witnessed a y-o-y decline of USD 70 billion in the outlook for both committed and planned investments,

weighed down largely by Saudi Arabia and lower prospects for Iran's gas sector. Committed projects declined by 17%, driven by a more than USD 11 billion and USD 5 billion drop in Iran and Egypt, respectively. Out of the nine countries that had committed upstream investments in the 2018 outlook, seven of them saw a y-o-y decline, including Iran, which saw its share of projects under execution fall by 77%. Libya, Iraq and UAE, on the other hand, are among the few countries witnessing an increase.

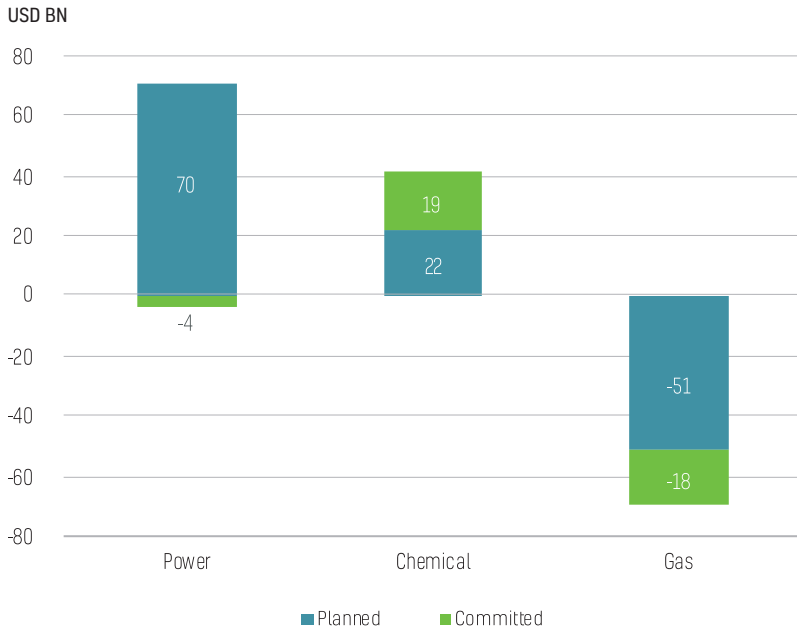
On the downstream side – with the exception of Qatar and UAE– committed investments declined, most notably in Saudi Arabia (60%) and Kuwait (close to 80%), as well as Algeria

and Iran whose downstream activity fell by around 50%.

These declines are not necessarily an indication of low investment appetite, but – in certain cases such as Saudi Arabia – rather a deceleration from a period of heavy activity and the commissioning of several major projects such as the Wasit Gas Plant.

Nevertheless, the private sector continues to shy away from major upstream projects, and with countries such as Iran and Algeria struggling in general to attract private sector investment, the risks on upstream developments materialising will continue to be high. The low gas prices are prompting investors to adopt a wait-and-see approach before committing to large- scale projects, including LNG facilities.

Net Change in Sectoral Investments 2019-2023 (USD BN)



Source: APICORP

On planned investments, two-thirds of the MENA countries will experience lower investments in their upstream gas sectors.

Reforms have contributed to lower gas demand growth, notably the reduction in energy subsidies and improved energy efficiency and renewables programmes. Yet, even though renewable energy is expected to claim a higher share of the power generation mix, there is still a risk of under-investment in upstream gas, as a fair number of the greenfield power projects – in Saudi Arabia (12GW) and Egypt (9GW) – will undoubtedly require additional gas supplies. Major upsiders may possibly come from Qatar, where

tenders for additional LNG processing trains – estimated at USD 15 billion – have recently been issued. Iraq meanwhile will continue its efforts to capture more flared gas and ramp up exploration for non-associated gas.

The declines in gas investments have been largely offset by significant increases in petrochemicals (50% year on year).

The increase in petrochemicals investments is part of efforts to further integrate the hydrocarbon supply chain – including refining – and maximise the value of each crude oil barrel.

Monetisation, and supply/demand balances, improving in many countries; areas of potential shortages remain

The era of tight supply/demand balances in the region over the past decade, which in a few cases led to fast-tracking sub-optimal short-term supply solutions seems to be over. Through a combination of domestic price reforms, upstream fiscal terms changes, and wider energy efficiency programmes, many countries succeeded in aligning the supply trajectory with demand growth targets.

Egypt expects continuous growth of gas consumption at an average rate of about 4% per annum (p.a.) for the next five years owed to power generation, gas exports and industrial development.

Egypt's Industrial Development Plan 2016-2020 forecasts domestic annual gas consumption to reach 72 billion cubic metres (bcm) in 2020 and 92 bcm in 2021. Thanks to new gas from Zohr, West Nile Delta (WND) and aggressive energy price reforms (fuel, LPG and electricity), the country achieved the first hydrocarbons fiscal surplus in five years in Q4 2018. As Egypt continues to capitalise on the Zohr discovery, the Ministry of Petroleum offered 10 offshore blocks in the Red Sea for international bidding in March 2019.

Saudi Arabia's gas demand to grow at an annual average rate of 1.8% to 2024, a deceleration on historical growth, with medium-term consumption largely driven by power generation and industrial activities.

Gas demand growth in Saudi Arabia has slowed down. Between 2008-2013, demand for gas grew at an average of 6.1% p.a. then tempered to 4.6% p.a. from 2013-2018. Power genera-

tion has been the main source of growth, with combined cycle gas turbines (CCGT) making up 27GW of installed power generation capacity – about 30% of total installed capacity.

With a little under 12GW of gas-fired capacity under execution, demand for gas in power will continue to remain strong. However, the outlook expects demand growth to slow over the medium to long term. The slowdown over the medium term will be governed by a more diversified fuel mix in power generation, the continuation of electricity price reforms and the enforcement of stricter energy efficiency standards on industry. To date, energy intensity of GDP in the Kingdom has decreased by 8% between 2012 and 2018, comparable to declines seen in the US.

Saudi Arabia has gone from gas tightness to excess gas and has ambitious plans to further increase its gas production from 127 bcm in 2017 to 235 bcm by 2026, thus boosting sales gas output from 89 bcma to 164 bcma. Gas demand growth however is unlikely to place significant pressure on supply in light of the competing fuels in power generation – including high-sulphur fuel oil given the IMO 2020 regulations - and growth in oil-derived feedstock in industry for new petrochemical projects.

That said, Saudi Arabia has been expanding its master gas system capacity to process both associated and non-associated gas. At the same time, Saudi Aramco is also developing its shale reserves. However, with cost of extraction in the region hovering around USD 6-10/mmbtu, the current scope is restricted to supplying the domestic market.

In the UAE, industrial needs will become the main driver for gas consumption over the coming years - especially in the petrochemicals sector.

Gas demand for power generation is expected to slow down to less than 1% p.a. to 2024 compared to almost 6% over the past six years, primarily due to the delayed commissioning of the four nuclear power units (5.6 GW) at Barakah and several solar power projects gradually coming online during the period.

On the upstream side, the UAE announced a 1.624 trillion cubic metres (tcm) addition to its conventional gas reserves in November 2019, catapulting it to sixth place globally in terms of gas reserves. It also became the first country in the region to list unconventional gas reserves of 4.48 tcm, as independently assessed by Rose and Associates.

In a bid to accelerate the exploration and development of its untapped resource potential outside developed production areas, ADNOC tendered two-thirds of its territory earlier this year, including a separate license for unconventional resources in Onshore Block 2 along its border with Saudi Arabia.

To achieve gas self-sufficiency and sustain LNG exports to 2040 as outlined in the UAE's Integrated Gas Strategy of November 2018, ADNOC is also pushing ahead with developing its costly sour gas resources in Shah, Hail Gasha and Bab in partnership with Shell, ENI, Wintershall, Total and recently Lukoil. To support these projects and boost oil production, the Supreme

Petroleum Council has already approved a USD 132 billion capital investment plan to fund ADNOC's 2019-2023 growth strategy.

On the import side, the UAE continues to source international gas through a combination of Qatari gas imports through the 33 bcma subsea Dolphin pipeline (capacity) and LNG imports from the two terminals in Abu Dhabi (3.8 Mtpa) and Dubai (6 Mtpa). On the LNG export side, ADNOC LNG, which used to supply solely Japan until last year, started selling spot LNG cargoes in Q3 2019 - mostly to India - after the expiry of its 25-year old contract with Japanese TEPCO in March.

Oman is another gas producer that went through a period of gas rationing for industries and electricity reform to honour part of its LNG export commitments, but its production is expected to increase.

Oman continues its upstream reform drive by awarding three blocks to international IOCs in 2019. Over the next five years, the Sultanate's gas production is expected to increase by 47 bcma from its current level of 40 bcma. This includes tight gas coming from BP's Khazzan which started production in September 2017 and is expected to increase its production from 10 bcma currently to 15 bcma and recover 295 bcm during its productive life. This increased production will underpin the 15% increase in the share of gas in the country's fuel mix (from 35% in 2015 to 50% by 2025).

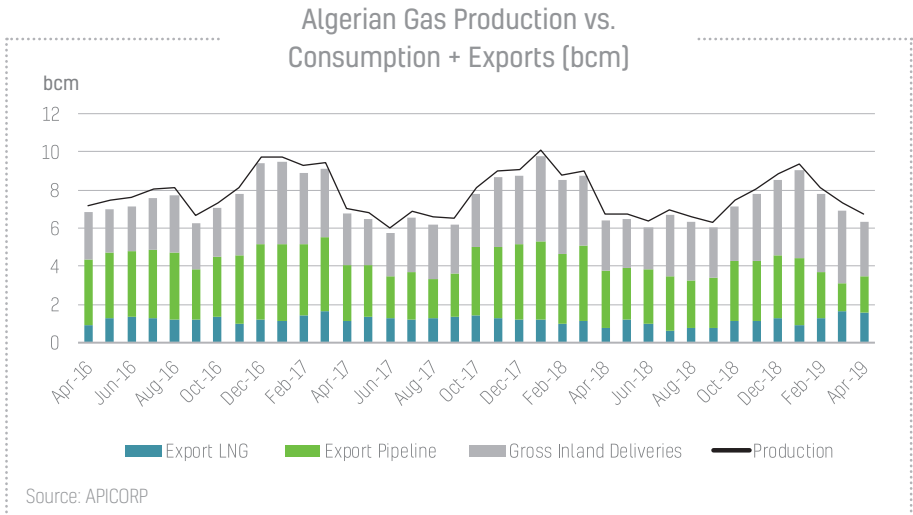
Country in Focus - Algeria

In vision SH2030, Sonatrach - Algeria's national state-owned company - unveiled

ambitious plans for the hydrocarbon sector, which have yet to translate in actual investments. Amidst the need to double output of new discoveries from 50 to 100 million tonnes of oil equivalent (mtoe) by 2030, emphasis was placed on “value over volumes.” Petrochemicals was singled out, but in our outlook, only USD 750 million is expected to be invested in the sector for projects currently at the FEED and study level for the period

2019-2023. And even if plans to develop this sector go beyond the medium term, adequate investment is needed to secure enough feedstock (natural gas and NGL). As such, a little over USD 8 billion in gas investments are anticipated over the next five years.

Over the past six years, Algeria’s gas exports have been dented by declining production, all while domestic consumption continued



to grow at a high rate of 5%. Together, these factors have put significant pressure on government balances in which hydrocarbons account for 95% of total export revenue. With the fall in energy prices, foreign currency reserves have unsurprisingly dropped sharply in less than five years to USD 73 billion, less than half of the USD 178 billion it held at the end of 2014.

Algeria’s upstream still challenged:

Notwithstanding an improvement in oil and gas prices, Algeria will have to address concerns over low upstream investments and access to much-needed technology for maturing fields – including the largest gas field Hassi R’Mel. The low appeal of the sector for foreign investments has hindered prospects for new discoveries and developments. The much-de-

layed New Hydrocarbons Law — designed to tackle fiscal terms, taxation issues and boost investment – is yet to go into effect, given the persistence of protests from the opposition. The legislation, passed by the lower house of parliament in November 2019 has yet to be ratified by the upper house. Furthermore, the uncertainties surrounding Algeria’s political transition are weighing down energy investments in the country.

Despite Sonatrach and ENI agreeing in February 2019 to accelerate Berkine gas development to 2.2 bcma and 7,000 barrels of condensate per day by Q4 2019, major projects are still challenged given bureaucracy in project development and implementation, as exem-

plified by the recent unexpected cancellation of the Sonatrach-Agip USD 100 million tender for the gas de-bottlenecking project at the Rhourde Oulad Djemma (ROD) field.

Although production stood at 96 bcm in 2018, exports decreased from 54 bcm a year earlier to 51 bcm, with both production and exports declining in 2019. Progress has so far been made from the reservoirs in the southwest region, with new supplies coming on stream from three groups of fields with a peak production level of 9 bcma. These long overdue additional volumes however will only provide a short-term fix.

Algeria’s New Southwest Gas Fields

Project	Commissioning	Projected production [bcma]	Consortium
Reggane Nord	December 2017	2.7	Sonatrach, Repsol, DEA, Edison
Timimoun	March 2018	1.8	Sonatrach, Total, Cepsa
Touat	September 2019	4.5	Sonatrach, Neptune Energy
Total		9.0	

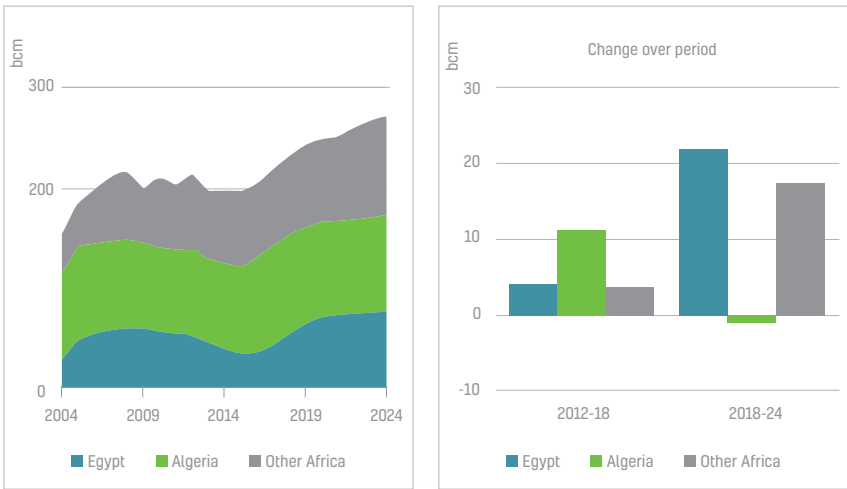
In parallel, demand continues to grow. In the 10-year period 2008-18, domestic gas consumption jumped by 70%. The power sector continues to account for the largest share of gas demand, as natural gas feeds 98% of the country’s total generated electricity. Although demand growth for electricity is expected to slow from 5% historically to 2% over the medium-term, gas-fired capac-

ity continues to feature heavily in new generation projects. In fact, USD 31 billion – or 56% of total energy investment – in Algeria is expected in the power sector, with a little under 8GW of gas-fired capacity currently under execution.

At 29%, industrial activity is the second-largest consumer of gas, benefitting from very low prices of USD 0.50/mmbtu. Industry is also where the Commission de Regulation de l'Electricite et du Gaz (CREG) projects the strongest growth (6% per annum), driven largely by the strategic push to better monetise Algeria's natural gas resources.

At a time when the country is challenged to address the fiscal imbalance, a decision must be taken on the level of reforms needed in natural gas subsidies – which last year cost the government USD 4 billion – to ensure that industry remains competitive and increase value through diversified product offerings.

Algerian Gas Demand Forecast 2020-2024 (bcm)



Source: IEA

Given the uncertain political climate, constrained government budgets and low energy prices, the need to increase volumes and value of exports is essential to continue financing public services. Herein lie several challenges the government needs to address. First, reforming the energy sector to curb demand and ensure targeted support for industry where it is strategically aligned with the view of maximising on the value of gas. Second, tackling the issue of gas flaring. Algeria currently flares the equivalent of 20% of its domestic consumption, second in MENA after Iraq. This is a major issue for two countries in dire need of ramping up gas production to address domestic demand and meet industrial growth targets.

To tackle the first two challenges, the country needs to have the vital infrastructure and investment in place first. The latter, however, is hindered by a bureaucratic administrative system that delays project execution.

Lastly, the renewable energy programme, which aims to install 22GW of capacity by 2030 and could reduce dependence on gas for power and increase government revenues if the country manages to export electricity, needs to be accelerated.

USD BN

4

Total cost of natural gas subsidies
in Algeria last year

GW

22

renewable energy capacity to be
installed in Algeria by 2030

Funding Trends and Private Sector Involvement

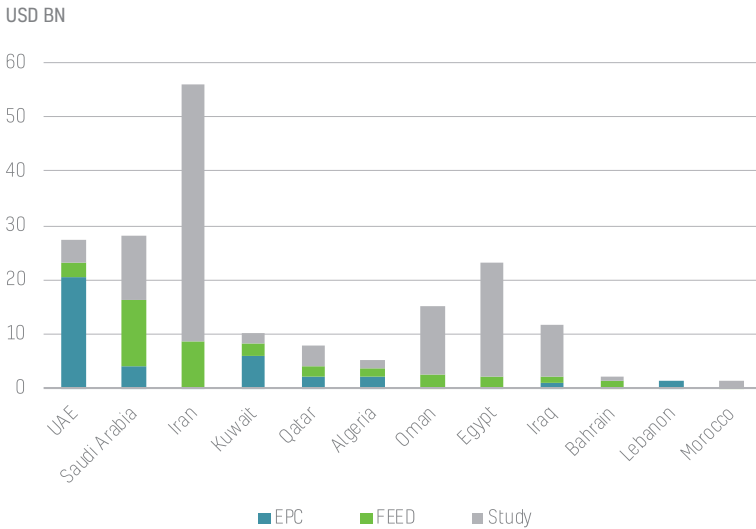
The share of government investments for committed upstream gas projects stands at a little under 92%.

This is less than the 61% committed to mid-stream and downstream projects and significantly less for petrochemicals, at 29%. Correspondingly, downstream and petrochemicals account for 71% of planned gas and petrochemicals investments compared to just 36% for projects currently under execution.

92%

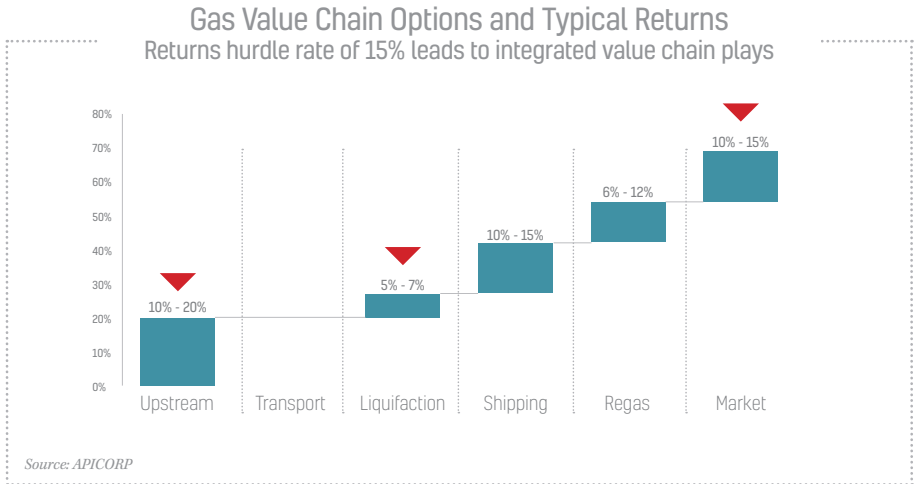
share of government investments for committed upstream gas projects

Planned Investments for Gas & Petrochemicals 2019-2023 (USD BN)



Source: APICORP

Returns are being squeezed across the whole value chain, including in upstream, shipping and in a few domestic markets.



Upstream gas projects continue to be largely financed by NOC's, IOC's and some independents.

Due to the higher upfront risks associated with exploration activity, which is keeping private sector participation more concentrated in the services sector, NOCs, IOCs, and some independent players are shouldering most of the financing for upstream projects. In the mid-stream side of the business, Abu Dhabi is interestingly preparing to potentially sell a minority interest in its gas pipeline network. Estimated at anywhere from USD 4 to 5 billion, the sale would be a first in the region and is expected to attract infrastructure funds and private equities.

The increasing wave of petrochemical megaprojects in the region and the few LNG terminals typically rely on a 70:30 - 80:20 debt/equity ratio.

The structure for project funding differs from one country to another. Bahrain for example

opted to fund projects on a PPP basis with a 75:25 debt-to-equity ratio. The Investment arm of the National Oil and Gas Authority – Nogaholding – develops the project on a Build-Own-Operate-Transfer (BOOT) basis and will hold a 30% stake. A syndicate of nine international and regional banks participated in a USD 741 million loan with K-Sure (South Korea's Export Credit Agency (ECA)) providing commercial and political risk cover for 80% of the financing. In addition to reducing the burden on the government budget and facilitating adequate financing for a duration of more than 20 years, this approach enabled the country to draw on the collective expertise of multiple parties across the private sector. Saudi Arabia, meanwhile, developed most of its petrochemical projects through JVs, for example the SATORP Petrochemicals Complex (Saudi Aramco, Total and INEOS).

Gas Pricing is Pivotal for the Industrial Sector and the Private Sector

Generally regarded as attractive propositions for the private sector given lower-cost feedstock, recent energy price reforms have questioned the competitiveness of MENA gas-based chemical plants.

The industrial sector accounts for roughly 30% of MENA gas consumption

The private sector's role is expected to expand given the increasing share of planned petrochemicals and other downstream gas projects (USD 134 billion or 71%) in the overall gas value chain versus upstream and midstream.

Competition from US ethane-based steam crackers and upcoming oil-to-petrochemicals schemes reinforced the need to build in more efficiencies, increase conversion rates (50% intended in Crude-Oil-To-Chemicals (COTC)) and increase integration between refining and petrochemicals. As natural gas is pivotal in supporting industrial agendas, its pricing directly affects the profitability and competitiveness of the different industrial sectors where it is used as a feedstock or a fuel.

Depending on policymakers' priorities and given the multiple utilisations of natural gas in utilities, industries and potentially transport, gas can be priced to achieve different objectives.

The below table summarises the different levels of valuation for natural gas and illustrates how – depending on the pricing framework chosen – different policy objec-

tives can be fulfilled. Domestic gas prices should not only cover production costs, but also reflect the value in each utilisation to ensure proper allocation of the resources.

For example, the threshold level for profitability and competitiveness varies from one industry to another (petrochemicals, cement, aluminium, fertilisers...). Assuming USD 35 per barrel price for Heavy Fuel Oil for example, gas prices for baseload power generation could increase to USD 7.5 per mmbtu before inducing fuel switching in the power sector. Although the export and import parity price levels will be country-specific, they would also be reflective of international gas prices netted back to the country's border.

71%

increase in the private sector share of planned petrochemicals and other downstream projects

Gas valuation hierarchy (illustrative- for a MENA country)

	USD / mmbtu
Import parity	TBD
Export parity	TBD
Alternatives in power (baseload)	USD 7.5 – 13
Industries competitiveness /profitability	USD 1.2 - 6.5
Marginal production	USD 2 – 5
Legacy production	USD 0 - 2 (maybe negative costs for associated gas)

For this reason, gas pricing frameworks and price reforms have taken different pathways in the region:

In Saudi Arabia, the pricing framework was designed in a paced, gradual manner to maintain the competitiveness of the Saudi industries, including petrochemicals.

In its Fiscal Balance Programme (calling for market-based prices by 2020) and through other communications, Saudi Arabia announced specific timetables for its energy price reform programme, including gas and ethane. For these two, industry and utilities prices will be 75% linked to international benchmarks (Henry Hub and Mont Belvieu, respectively) and carry a price cap. NGLs, another petrochemical feedstock, were already linked to market prices (90% of netback price in 2018). In parallel, effective September 2019, the Council of Ministers passed a resolution “removing the requirement that the domestic price be no less than the ‘Blended Price’”- the price due to the licensees (i.e. Saudi Aramco) for the domestic sale of regulated gas products.

Despite proven reserves in excess of 3.5 tcm, Iraq suffers from gas supply shortages.

With plans to fuel many of the new gas-fired capacities expected to be commissioned over the medium to long term – and even more to feed any potential for petrochemicals and fertiliser plants – the country will have to ramp up gas production. Already, existing plants are being supplemented by imports from neighbouring Iran - where the cost of imports is a little over USD 7/mmbtu – and filling the remaining gap by either burning liquids or importing electricity.

Aside from the huge potential to develop both associated gas – which accounts for the majority of reserves including those in the supergiant fields in the south – and non-associated gas – such as the Mansuriyah field – Iraq continues to flare more than half of the gas it currently produces, which nonetheless an improvement from 2016 when over 70% of the gas was flared. Basrah Gas Company (BGC) has prioritised an initiative to capture the flared gas, yet the country will need to do

TCM 3.5

proven gas reserves in Iraq

more in attracting private sector investment to supply the domestic market and reduce expensive imports.

Because BGC's pricing terms are linked to heavy fuel oil, and hence Brent price, a Brent price of USD 75/b means the price of gas will be around USD 3.2/mmbtu. Customers (i.e. power plants) will then purchase the resulting dry gas at USD 1.20/mmbtu, resulting in the government bearing a huge burden to cover the gap between the lower domestic prices and those agreed with BGC.

Reforming gas prices – and by extension electricity prices – is a must if investors are to be assured of the financial viability of these projects. Of even more importance is to provide a long-term assurance of a gradual hike in prices over a 5 to 10-year period that will ensure the development of fields to meet growing domestic demand, and substitution of expensive gas imports over the longer term.

These measures should ultimately spur private sector investments in the power sector and industry, reduce volatility associated with international oil prices and reduce the fiscal burden on the government. The ability to ramp up production should position Iraq

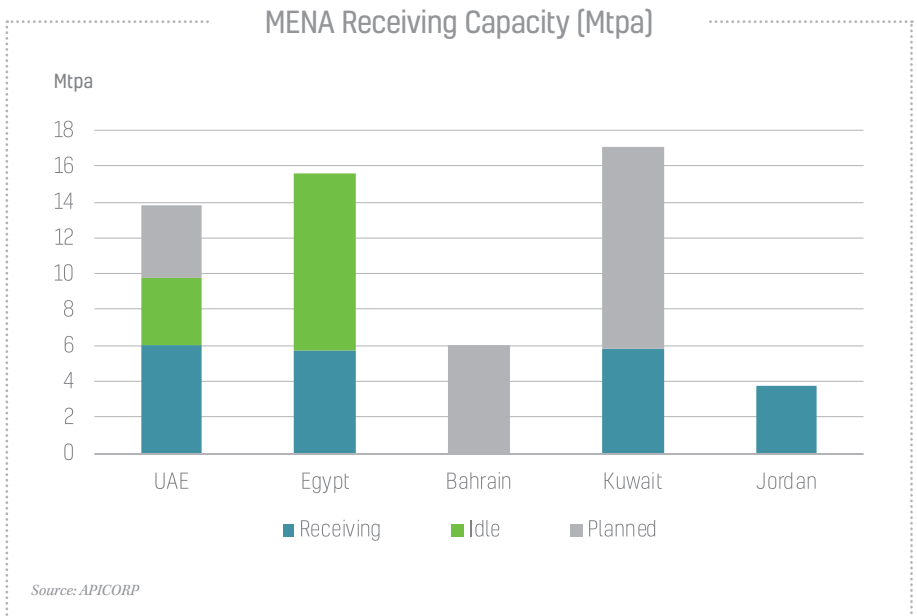
as an important regional exporter to neighbouring Turkey, Jordan and even Kuwait, and underpin the strategic importance of the country to sustain regional cooperation and cross-border trade.

In Egypt, a pricing framework for domestic gas has been set-up.

The domestic pricing framework is part of the wider energy pricing reforms that started in 2015 aimed at not only reducing subsidies and their toll on the government's fiscal balance, but also to offset the increased cost for developing the new upstream deep offshore natural gas – contractually priced between USD 3.5/mmbtu and USD 5/mmbtu where the government of Egypt has to pay the IOCs these off-take prices.

The reforms raised the domestic gas prices for industry consumers and cement producers to USD 7/mmbtu and USD 7.5/mmbtu, respectively, through an indexed formula that can be revised upward or downward and according to international energy prices, mainly Brent. In September 2019, the Egyptian government revised down the prices of industrial gas for industry consumers and cement producers to USD 5.5/mmbtu and USD 6/mmbtu, respectively, prompted by the sharp decrease in global gas prices – notably LNG – and mounting pressures from industrial consumers. There is more worry to such relatively high domestic gas prices vis-à-vis global gas prices in case the latter continue to be depressed.

Despite Hubs Ambitions, Regional Connectivity Still Low: LNG Competes with Pipelines



Regional gas connectivity is still very low given the availability of gas resources and the different requirements among the countries.

There are currently three cross-regional operational pipelines compared to five such pipelines in 2010. In a period of possibly lower gas prices, the expiration of existing contracts presents opportunities for renegotiations given the piped gas prices (e.g. USD 5/

mmbtu AGP versus USD 6/mmbtu LNG CIF Aqaba). Transit fees are also reviewed, as Tunisia was able to revise the transit fee of the 34 bcma Algeria-Italy pipeline to 5.25%. Under new terms (Jul 2019-2029) Trans-Tunisia will generate approximately USD 174 million of annual revenue to the Tunisian government in tariffs and transportation fees.

The lack of connectivity has benefitted LNG, and the latest LNG regasification terminals added in the region are on track in Kuwait and the UAE.

Kuwait's USD 3 billion, 11.3 Mtpa Al Zour Terminal is more than two-thirds complete, with a target start date sometime in 2020.

On the supply side, Qatar continues to retain its position as the MENA's top gas exporter and is moving ahead with upgrades that will see its liquefaction capacity rise from current 77 Mtpa to 126 Mtpa by 2027. The country has plans to nearly double its 65-strong LNG fleet by adding at least 60 new carriers at an estimated cost in excess of USD 12 billion, growing the current global LNG fleet of 525 carriers – as of Q4 2018 – by 11-19%.

Egypt meanwhile resumed LNG exports from Idku Plant (10 bcm in Q1 2019) and projects doubling this figure to 20 bcm in 2020. Oman's LNG exports are at full swing, with three LNG export trains operating at full capacity.

The new supply flows re-opened ambitions to establish a 'Gas Hub' in the region.

This is frequently touted by countries with vast natural gas resources and steady inflow and outflow volumes. The original ambition behind the Dolphin gas pipeline between Qatar, UAE and Oman was indeed to create the backbone of a gas hub in the GCC.

If executed properly, hub participants can reap long-term socioeconomic, political and security benefits, but achieving a well-functioning gas hub requires some conditions. Mature gas hubs include the Dutch TTF and the British NBP

(National Balancing Point) – which accounted for 87% of the European gas trade in 2018.

Egypt has a concept for a modern gas hub, but key elements are still amiss

These include expedited development of gas fields and subsea facilities, price reforms and liberalisation of Egypt's midstream and downstream gas supply and trading activities, third-party access, gas storage, more infrastructure capacity, and sellers/buyers.

The key ingredients of a functioning Gas Hub include:

1) Steady Supply Availability:

The availability of ample and sustainable gas supplies fosters the attractiveness of a region in catering for demand. For example, the Netherlands' gas 2018 year-end reserves at 600 bcm and yearly production at 32.3 bcm, serving as backbone for the mature Dutch TTF.

2) Strong Regional Demand:

The proximity of strong markets forms the other side of the trade equation. There are concerns about Egypt turning into a net deficit as soon as 2025, owing to high domestic consumption and once its 12 Mtpa LNG trains operate at full capacity. Jordan currently needs approximately 6 bcm, of which more than half are already being met through LNG imports, while Lebanon is estimated to currently consume around 3 Mtpa of LNG, equivalent to 4.2 bcma.

3) Physical Infrastructure:

The availability of a reliable infrastructure in terms of transmission pipelines, metering,

storage, gas liquefaction and regasification is the physical medium that joins the two sides of the trade equation. The TTF gas hub established in 2003 only gained prominence after the implementation of the Gas Roundabout in 2006, a connected junction of gas infrastructure elements for production, transport, storage, transit, trade and knowledge development.

4) Macro Environment (Political, Economic, Security, and Regulatory):

Alignment on regulations, governance, monitoring and supervision will be required. The independence of the institution that answers to a regional Board of Directors and governors is required. Political stability domestically and regionally is crucial to the development of a gas hub. Also, a stable and healthy economy reinforces political stability and supports a minimal level of domestic demand that contributes to the trade activity of the gas hub. Reform in laws and jurisdictions (up to constitutional amendments) to address issues like deregulation of upstream and downstream activity to allow multiple sellers and buyers of gas, usage of financial instruments (hedging, arbitrage and derivatives) ownership, governance, control, sovereignty, tax treatment and customs tariffs and clearances, may be required.

5) Market Liberalisation:

Whether they are on the buyer-side or the seller-side, monopolies generally hamper liquid trade. Unbundling of some entities in the gas value chain might therefore improve liquidity. For example, the UK succeeded in establishing NBP as a strong gas hub after ef-

forts to privatise British Gas and pushing the 1986 Gas Act. Similarly, TTF gained prominence only after the European Commission vowed to establish an integrated energy market on fair terms for all consumers around the Dutch gas supply hub bordering Germany, Belgium, Denmark and France. The European Commission further legislated the “3rd Package Directive” in 2009 providing legally-binding Network Codes for a single energy market for gas and followed that by the “Gas Target Model,” which detailed the codes necessary for Over-the-Counter (OTC) and Exchanges for futures contracts. A minimum threshold churn rate of 15 is considered a requirement for a credible and mature gas hub. TTF’s churn rates for 2018 was 71.

6) Supporting Infrastructure:

Like a stock exchange, a gas hub – whether physical or virtual – intrinsically requires a strong supporting infrastructure in its composition: trading and hedging platforms, financial settlement and clearing, registries and ledgers, insurance tools with the presence of modern and reliable information and communications (ICT) systems and necessary cybersecurity.

7) Security:

To ensure stable, uninterrupted and long-term operation of a proposed gas hub, both the homeland and regional security environments must score moderately high for the entire value chain of the hub (i.e. suppliers, intermediaries and consumers) due to the magnitude of upfront investment required from all stakeholders, but more so on the hosting country’s side (i.e. the market itself).

Domestic security ensures safe and uninterrupted operations vital for a functioning gas hub while regional security adds the necessary long-term stability aspect that gradually establishes credibility and maturity of the gas hub.

In the MENA region, the only limited attempt to create a gas hub occurred with the inception of the 33-bcma Dolphin pipeline between Qatar, UAE and Oman. Fast forward to 2017, the numerous discoveries in the East Mediterranean region to date shifted the balance to this new deep offshore province and spurred renewed exploration activity by international oil companies and independents. In theory, with the volumes that would potentially flow, the Eastern Mediterranean may qualify as a potential gas hub.

Costly FLNG or European export options rendered the development of deep offshore gas difficult. Egypt's combined 12-Mtpa LNG plants came back online after the Zohr gas discovery. And yet, even with Zohr, there are concerns that plateau production will not last more than ten years.

The East Mediterranean Gas Forum (EMGF) was born in January 2019 to utilise existing gas pipeline and LNG infrastructure as an export medium for stalled regional gas finds in both Israel and Cyprus, in addition to achieving synergies from Zohr, and later the smaller Nour. The EMGF – which initially started with Egypt, Jordan, Israel and Cyprus, was subsequently joined by Greece, Italy and later Palestine – primarily aimed to assist with the creation of a regional gas market by securing supply and demand, optimising resource development and cost of infrastructure, improving commercial relationships and competitive pricing.

Regional Gas Balance

Country	1P Reserves bcm ¹	Annual Production Capacity bcm	Reserves / Production Yrs
Egypt	2100	80	26
Israel	400	23	18
Cyprus	238 (Est.)	6	40
Jordan	0	0	0
Lebanon	0	0	0
TOTAL	2738	109	25 years

Country	Annual Consumption Peak bcm (2025)	Annual Balance bcm	Comments
Egypt	76	4	Given no new reserves additions, plateau declines post 2025
Israel	14	9	Agreement to supply 7bcm _{pa} to Egypt
Cyprus	1	5	Estimate. Almost all Cyprus power generation uses fuel oil.
Jordan	8.5	-8.5	Estimate based on 2016-2018 consumption
Lebanon	5	-5	Estimates from FSRU tender design capacity
TOTAL	104.5	5.5	Combined balance for countries based on peak cross-trade

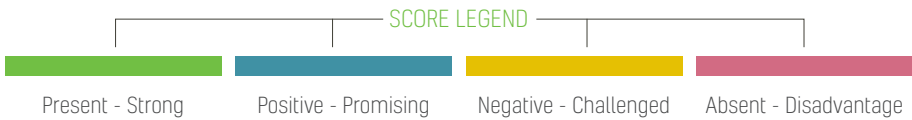
¹ Source: IEA, APICORP, Brussels Energy Club, Cyprus Regulatory Authority, Lebanese Ministry of Electricity & Water

APPENDIX: Egypt’s proposed Gas Hub: A comparative advantage analysis

Egypt officially announced its aspiration to establish the East Mediterranean Gas Hub as the ideal candidate. An analysis of the comparative advantages and challenges Egypt has in its bid to host the potential gas hub will be done

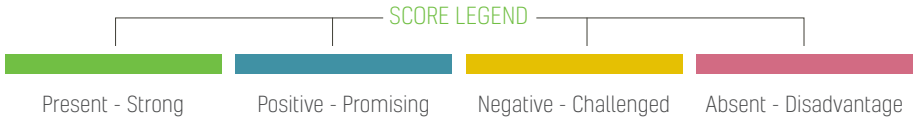
through: (A) Qualitative SWOT analysis based on the key criteria previously highlighted and (B) A comparison between Egypt and regional contenders based on the same key criteria.

A) EGYPT: Gas Hub diagnostic (part 1)



COMPONENT	WHAT IS AVAILABLE	WHAT IS MISSING
1) Steady Supply Availability	<ul style="list-style-type: none"> • Egypt’s gas reserves sustain current high production, domestic consumption and exports for several years • Additional 10-yr supply from Israel and Cyprus granted 	<ul style="list-style-type: none"> • Subsea pipeline from Cyprus to Egypt bringing Cypriot gas to Egypt operational by 2022 • Currently depressed global LNG prices stress East Med due to costly offshore gas in three countries)
2) Strong Regional Demand	<ul style="list-style-type: none"> • Strong and increasing Egyptian domestic demand • Regional demand include Jordan, Israel, Lebanon and Palestine addition to European market 	<ul style="list-style-type: none"> • Clear long-term energy policies in major neighbouring demand markets (e.g. Lebanon)

COMPONENT	WHAT IS AVAILABLE	WHAT IS MISSING
3] Physical Infrastructure and Storage	<ul style="list-style-type: none"> • Egypt enjoys a mature gas infrastructure of a vast network of transport and distribution lines • Gas processing plants and two LNG export trains with a total capacity of 12 Mtpa • Israel-Egypt gas pipeline now operational • Several depleted gas fields can be used as storage for transit/surplus volumes 	<ul style="list-style-type: none"> • Cyprus-Egypt pipeline under construction, possibly operational by 2022 • Damietta LNG still not operational pending resolving the dispute with UFG • Underground gas storage capacity required to accommodate transit/surplus volumes from Israel and Cyprus will require testing and then commissioning
4] Macro Environment [Economic, Political and Regulatory]	<ul style="list-style-type: none"> • Egyptian Economy recovering from turmoil with stable growth outlook • Egyptian pound steadily recovering since 2016 flotation • Energy Sector reforms have progressed a long way • Strong political will for modernisation. Gas hub development is on top of state priorities and capitalises on Egypt's relationships with regional stakeholders, initiated and hosts the EMGF that now includes Palestine. 	<ul style="list-style-type: none"> • A plethora of legacy and overlapping legislations • A standing arbitration with UFG on Damietta LNG plant • Complicated by the doubtful public perception on the benefits of establishing a gas hub in Egypt due to weakness of communication and public engagement • Absence of a Financial Markets Law is a barrier for a functioning gas hub



A) EGYPT: Gas Hub diagnostic (part 2)

COMPONENT	WHAT IS AVAILABLE	WHAT IS MISSING
5) Market Liberalisation	<ul style="list-style-type: none"> Privatisation of key components in midstream/ downstream accelerated since 2017 with private players in key components of the energy value chain A Gas Regulatory body established in 2017 	<ul style="list-style-type: none"> Liberalisation of the natural gas value chain will be very challenging from legislations side Financial market law, transfer of ownership, entitlement and title transfer to achieve liquidity and threshold churn rates for a liquid gas hub Liberalisation can overlap with other non-energy state jurisdictions of other governing bodies as the 'un-bundling' process is currently challenged

COMPONENT	WHAT IS AVAILABLE	WHAT IS MISSING
6] Supporting Infrastructure	<ul style="list-style-type: none"> Like a stock exchange, a gas hub – whether physical or virtual – intrinsically requires a strong supporting infrastructure in its composition: trading and hedging platforms, financial settlement and clearing, registries and ledgers, insurance tools with the presence of modern and reliable information and communications (ICT) systems and necessary cybersecurity 	<ul style="list-style-type: none"> Setting up the non-physical virtual gas hub infrastructure is required: IT, monitoring and control, trading platform and codes and capable human resources Setting-up a governing body for the gas hub from EMGF stakeholders needed to guarantee transparency and credibility
7] Security	<ul style="list-style-type: none"> Most of the additional facilities to be put in place for the gas hub are in a controlled environment (offshore and virtual) thus resilient against physical sabotage 	<ul style="list-style-type: none"> In addition to conventional security vulnerability of physical assets, non-conventional security threats related to ICT need to be mitigated

SCORE LEGEND



B) EGYPT VS Neighbours: Gas Hub competitiveness

COMPONENT	EGYPT	CYPRUS	TURKEY
1) Steady Supply Availability	<ul style="list-style-type: none"> • Egypt proved gas reserves + Cyprus + Israel gas guarantee sustained high volume long-term supply 	<ul style="list-style-type: none"> • Cypriot undeveloped gas reserves combined with country's low consumption guarantee a healthy and prolonged supply potential 	<ul style="list-style-type: none"> • Turkey lacks domestic gas reserves. Russia and Iran provide more than 50% of Turkish gas imports. Russian gas has a destination clause to Turkey, cannot be re-exported. Iranian gas has no re-export appeal due to sanctions
2) Strong Regional Demand	<ul style="list-style-type: none"> • Egypt + Jordan markets guarantee healthy demand; potential markets of Lebanon and Palestine add to demand strength 	<ul style="list-style-type: none"> • Proximity to a southern Europe, Egypt, Lebanon and Jordan 	<ul style="list-style-type: none"> • Healthy domestic demand combined with presence of regional markets of Georgia, Balkans and potentially Ukraine
3) Physical Infrastructure and Storage	<ul style="list-style-type: none"> • Egypt has the most developed gas and export infrastructure in East Med in addition to regional cross-border pipelines 	<ul style="list-style-type: none"> • Absence of gas and export infrastructure in Cyprus 	<ul style="list-style-type: none"> • A historic corridor between Asia and Europe, Turkey has a developed gas infrastructure and regional connectors to Europe and Russia/Caspian

COMPONENT	EGYPT	CYPRUS	TURKEY
4) Macro Environment (Economic, Political and Regulatory)	<ul style="list-style-type: none"> • Strong Economic and Political environments but highly challenged regulatorily due to conflicting regulations, overlapping jurisdictions 	<ul style="list-style-type: none"> • Good Economic and Regulatory environments (EU country) but Politically challenged due to standoff with Turkey on northern exclave 	<ul style="list-style-type: none"> • Worsening economic and political environments on domestic, regional and international levels. Challenged regulatory environment due to increased political meddling in regulatory bodies and economic activity.
5) Market Liberalisation	<ul style="list-style-type: none"> • Strong barriers to full market decentralisation and free trade activity despite recent radical reforms 	<ul style="list-style-type: none"> • Cyprus enjoys a free market culture and system owing to its history as a free trade, financial services and tourism hub 	<ul style="list-style-type: none"> • Turkey enjoys a free market culture and status owing to its history as a global trade corridor and tourism hub
6) Supporting Infrastructure	<ul style="list-style-type: none"> • Strong human resources and ICT infrastructure. Missing steps for free trade and gas hub liquidity can be easily implemented 	<ul style="list-style-type: none"> • Strong human resources, ICT infrastructure and free trade activity that are strong enablers for a gas hub 	<ul style="list-style-type: none"> • Strong human resources, ICT infrastructure and free trade activity that are strong enablers for a gas hub
7) Security	<ul style="list-style-type: none"> • Capable homeland, border and maritime security. • Healthy relations with regional and international stakeholders 	<ul style="list-style-type: none"> • Despite the EU guarding Cyprus from serious Turkish threats, tensions have flared with no signs of de-escalation after recent sizable gas finds in Cyprus with Turkish claims to Cyprus maritime economic zones 	<ul style="list-style-type: none"> • Worsening and volatile security situation with Turkish army engaged in Syria and Iraq. Frequent skirmishes with Cyprus and Greece on maritime borders, deteriorating relations with EU and the US / NATO allies in addition to regional powers Egypt and Israel

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