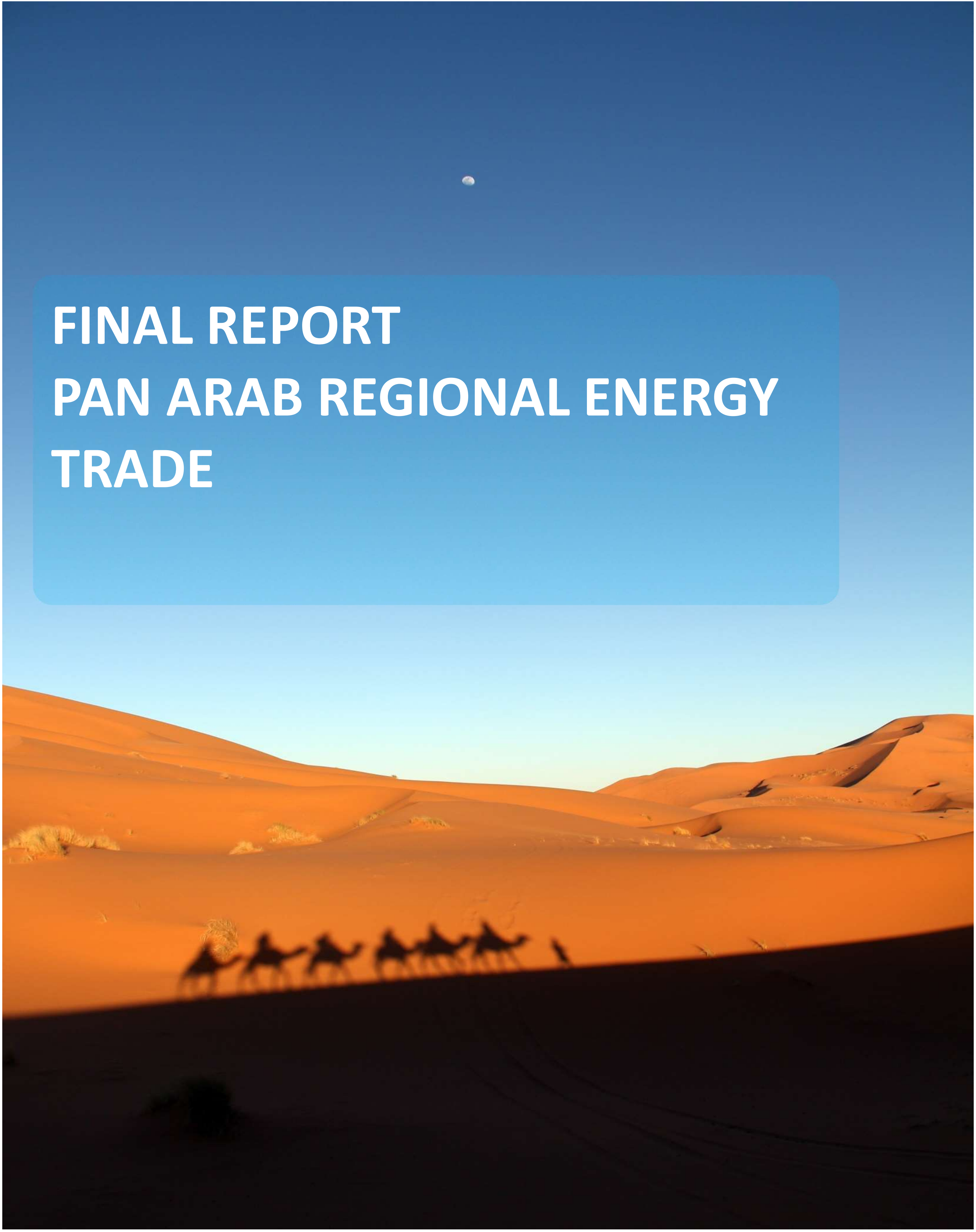

FINAL REPORT
PAN ARAB REGIONAL ENERGY TRADE

SUPPORTED BY WORLD BANK GROUP

PPIAF Enabling Infrastructure Investment

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ANALYTICAL FOUNDATION FOR INCREASED PAN-ARAB REGIONAL GAS TRADE
FINAL REPORT

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ANALYTICAL FOUNDATION FOR INCREASED PAN-ARAB REGIONAL GAS TRADE

FINAL REPORT

Revision	**Final Report**
Date	**1st of September, 2017**
Made by	**Bent Svensson, Søren Løvstad Christensen, Per Jørgensen, Anatoli Smirnov, Emiliano Catalini**
Checked by	**Søren Løvstad Christensen, Bent Svensson, Therese Henriksen, Andrew Somerville**
Approved by	**Per Jørgensen**
Description	**Final Report**

Ramboll
Hannemanns Allé 53
DK-2300 Copenhagen S
Denmark
T +45 5161 1000
F +45 5161 1001
www.ramboll.com/oil-gas

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1. INTRODUCTION

1.1 Background

In cooperation with CESI as sub-contractor, Ramboll has been engaged by the World Bank to provide an analytical foundation for increased Pan Arabian Regional Gas Trade.

The World Bank, its partners and the League of Arab States, are embarking on a Pan-Arab Regional Energy Trading Platform (PA-RETP) project to address regulatory, governance and pricing issues. This includes development of regional trade enablers such as a pricing mechanism, regional institutions such as a regional independent system operator and a regional regulatory authority, and governance documentation such as a regional grid code covering technical aspects of regional trade, and a commercial code, or market rules, to govern commercial aspects of regional trade.

The PA-RETP project will also address infrastructure/investment requirements necessary to afford regional trade. This will include identification of priority projects and funding solutions. The ultimate goal is to create a **single integrated competitive electricity market** (i.e., Pan-Arab Electricity Market - PAEM) **and gas market** (i.e. Pan-Arab Gas Market - PAGM), and the regional institutions necessary to increase regional energy trade.

Compared to the electricity market, additional steps are foreseen to develop the PAGM. These would include identifying a champion(s) from the region, initially from countries with a pressing shortage of gas to meet domestic demand supplemented by current gas export countries seeking security of demand to explore the scope for developing a shared gas trade vision and establishing a PAGM. If political commitment for a PAGM can be established, two tracks similar to that of the PAEM could be pursued to further advance regional gas trade at the sub-regional level:

(1) Launching the process of systematic phase-out of gas-price subsidies and establishing regional institutions and legal and regulatory frameworks that focus on -
(i) transparencyof information,
(ii) enhanced investment
(iii) regulatory convergence

(2) Preparing investment initiatives in new and/or existing infrastructure (regional and country) with focus on both pipelines and LNG to promote gas trade.

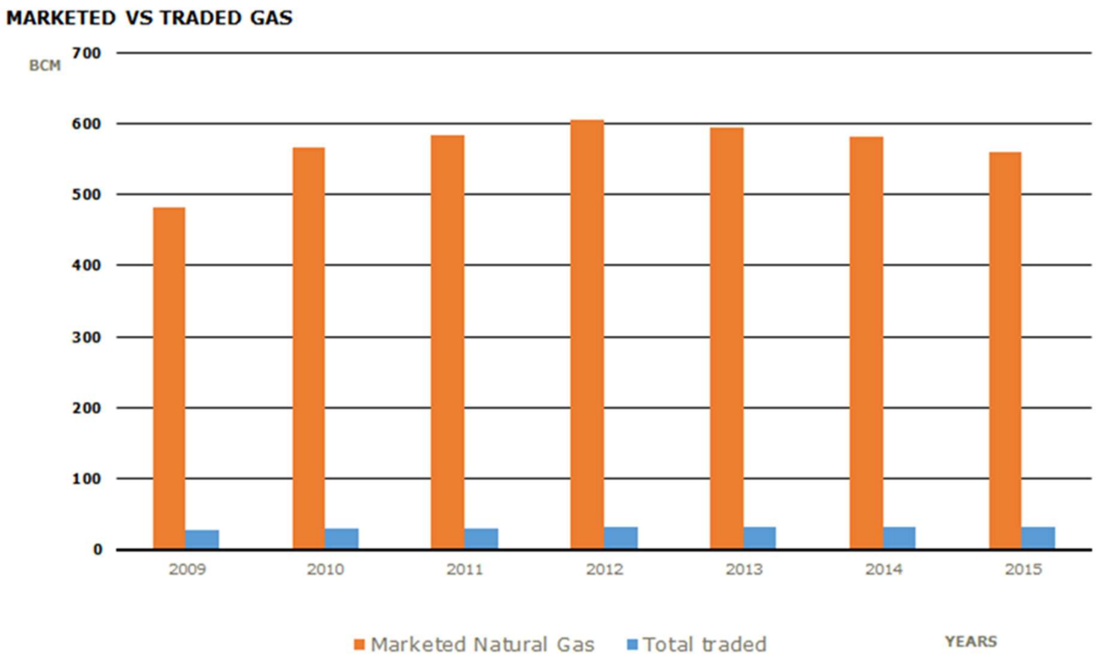
The World Bank and the League of Arab States plan to jointly host a seminar for decision-makers from the region in 2017 where the aim is to:

- define the case for change moving towards an integrated gas market
- share international experience with regional gas trade
- define the barriers to trade in MENA
- prioritise and sequence the resolution of barriers; brainstorm political and commercial solutions identify the scope for institutional and regulatory cooperation and quick infrastructure wins
- draft a shared vision for regional gas trade
- define an action plan

1.2 Problem statement

Experience from international developed gas market regions (Europe and the US), where some countries are endowed with substantial resources of gas and others are not, has shown that trade within and between countries does take place. Gas is being moved between regions at prices which are mutually acceptable for both sellers and buyers. Marketed gas finds its ways to domestic and neighbouring markets and seldom leaves the region. In the MENA region, the opposite is the case - while marketed gas has increased from below 500 bcm/y (2009) to almost 600 bcm/y in 2014, traded gas between MENA countries has remained at a relatively low and stable level of 20-30 bcm/y in the same period (see Figure 1).

Figure 1: Marketed Natural Gas vs. Traded Gas MENA region

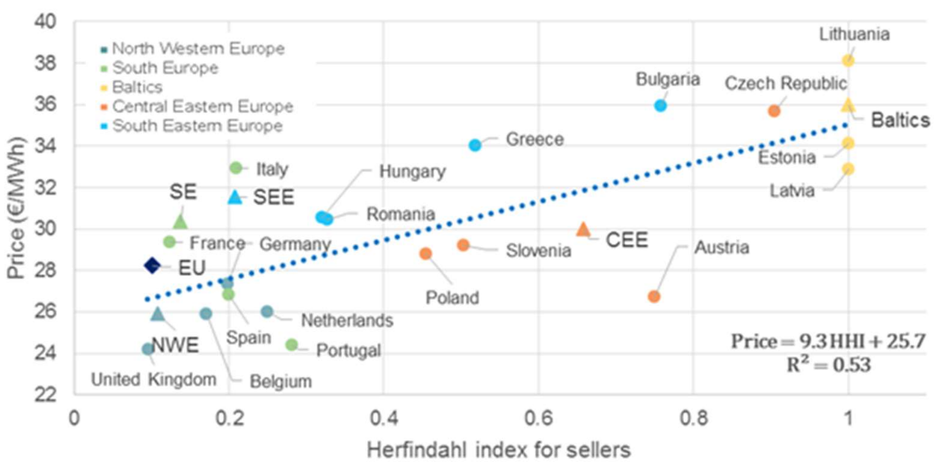


Source: OAPEC (excluding Iran) & IGU.

The benefits of trade between countries and regions are potentially significant; moving gas from low cost regions and countries to countries and consumers who are not endowed with the same resources is a win-win situation for everyone. The benefits of trade come in the form of:

- Lower overall gas and electricity prices resulting in welfare improvements across consumer groups and countries. Experience from the EU shows that interconnected countries with access to several sellers realise significantly lower gas prices than countries with fewer or no possibilities for trade (see Figure 2).

Figure 2: Country price (2012-2013) vs Herfindahl index for gas sellers to each country



Source: Economic analysis of costs and benefits of approaches to enhancing the bargaining power of EU buyers in the wholesale markets of natural gas Ramboll, Vivid Economics, & Ecorys 2015

- Cleaner and more efficient power production with fewer emissions and knock-on benefits to the environment
- Enhanced and cheaper realisation of security of supply. Integrated networks and trade across borders makes it easier and cheaper to handle security of supply issues

Thus, the lack of trade amongst countries in the region comes at a high price, and significant improvements in trade are yet to be seen despite the potential benefits. Many of these countries do still have significant subsidy schemes for natural gas in place – subsidy schemes that distort price signals and draw on the finances of the respective states. Security issues along the routing of onshore pipelines have shown to be a major issue and are currently preventing potential trade in the Arab Gas Pipeline. Finally political disagreements, border disputes and regional rivalries, resulting in lack of trust among neighbouring countries, have historically been a major hurdle for projects to move ahead.

1.3 **Window of opportunity for increased Pan-Arabic gas trade**

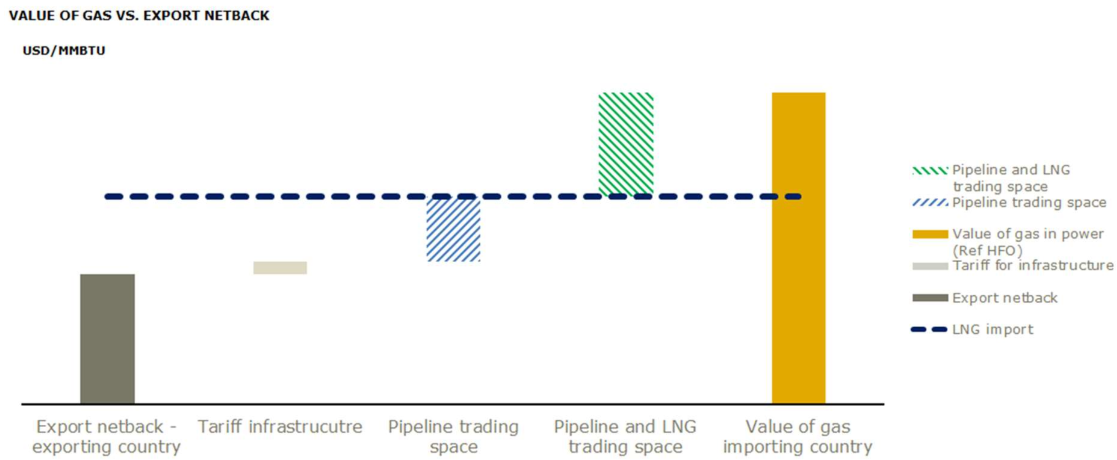
At present there seems to be a window of opportunity for increased Pan-Arabic gas trade following the decline in oil and gas prices in 2014 and 2015 respectively. The oversupply of gas, triggered by LNG from Australia, USA, Russia, and Qatar to the global gas market has resulted in lower prices in Europe and in Japan, Korea and China in particular. Additionally, the change of OPEC policy in 2014 to gain larger market shares, and the following decline in oil prices, have resulted in severe balance of payment and financial deficits in many oil producing countries. The larger oil production in Saudi Arabia, Kuwait, UAE, Iran and Iraq after the change of OPEC policy increased associated gas production. Saudi Arabia, which used to consume large quantities of oil for power production may need this oil for increasing their market share, a situation which opens for increased use of gas for power production. With respect to the latest OPEC policy, restricting production has so far not had any significant effects on prices but could affect the associated gas production.

The lower gas prices will make gas affordable for emerging economies including a number of MENA countries with no or small gas reserves. New greenfield LNG export terminals in the region do not seem to be economically viable at today's gas prices and will hereby tend to encourage use of existing pipeline routes and LNG import terminals and potentially upgrading or establishing of new pipeline interconnectors within the region.

Low oil and gas prices make it appear that level of subsidies has fallen, when using the international prices as benchmark. At the same time the oil and gas producing countries will have difficulties in maintaining very low indigenous gas prices due to balance of payment issues, budget deficit, and lack of gas which may trigger price reforms in producing countries.

In a low gas price environment gas producing countries do not have a huge windfall profit from exporting.. At the same time, importing countries are faced with the tough choice of selecting the lowest cost thermal generation mix, a choice which often favours gas as it is less polluting, more flexible and more efficient than both oil and coal fired generation. Even with oil prices in the range of 50 to 60 USD/bbl, the value of replacing existing oil fired generation is high (above 10 USD/MMBTU). This leaves a trading space, defined as the area where both sellers and buyers are better off, between the export netback and the value of gas in the importing countries.

Figure 3: Value of gas vs. export netback



Source: Ramboll

With increased international competition for supply of gas and a decoupling of oil and gas prices we believe that this trading space will be expanding and offer increased incentives and opportunities for trade between countries.

1.4 Summary of this Project

Through analytical work on gas prices and regional gas markets, this project aims to shape the analytical foundation required in order to launch initiatives that enhance regional trade in the region. The work focuses on the following overall activities:

1. Develop pricing models for regional gas transactions.

2. Identify barriers to and ifor regional gas integration and develop optimum solutions

3. Compile international experience with regional integration of gas markets and lessons that can be learned.

1.5 Overview of this report

This report is divided into 10 chapters.

In Chapter 2 we present the main findings and recommendations for enhancing trade in the region.
In Chapter 3, we take stock of the current situation with respect to trade between the MENA countries and the existing infrastructure.

Chapter 4 summarises the country level results with respect to supply and demand for gas and provides and overview of the future gas balances in terms of production, consumption, import, and export until 2030.

Chapter 5 provides perspectives of the current security of supply situation and discusses the role which underground gas storages could take in the region.

Chapter 6 examines the barriers and opportunities of trade.

Chapter 7 focuses on subsidies the current status and the plans to phase out subsidies in the region. Additionally several case studies on subsidy reforms are presented in this chapter.

Chapter 8 investigates the incentives to trade taking the economic prices of gas from export and the value of gas in importing countries into account identifying mutually acceptable trading spaces between countries.

Chapter 9 present the experiences from the EU and case studies from within and outside the region.

Chapter 10 contains the individual country summaries and analysis on supply and demand, subsidies, and prices.

2. MAIN FINDINGS AND RECOMMENDATIONS

Experience has shown that development of trade and integrated gas markets does not happen overnight within a region. Countries and local gas markets develop in different tempi based on different endowments and constraints. Thus a starting point for any additional gas trade to develop is to recognize that one unified regional gas market with the characteristics which we see in the EU and other places today is unrealistic in both the short and medium term. Countries should rather focus on developing their domestic gas markets from the bottom and focus on a step-wise approach for integration. This is achieved by implementing reforms addressing availability of gas, internal pricing, and renewable energy. By doing so, countries could, in their own pace, approach a situation where gas is available for trade and where pricing incentivise trade across borders, while keeping the cost as low as possible.

The timing for such reforms seems to be better than ever, oil and gas prices are low, implying a low gain from exporting any available gas out of the region, at the same time gas is available in certain countries including Qatar, Iran, and partly Algeria if new reserves are added to the existing. For this gas to find markets at least 2 main barriers must be overcome. First of all the political barriers and the lack of trust amongst countries imply little willingness to trade with one another. For this reasons countries are willing to pay a risk premium for gas. Secondly, the pricing must happen at prices which do not make the seller of gas worse of compared to export and at the same time is competitive with alternative fuels and options in the buying country. We find that such a trading space exists between most countries, but to utilize it fully, internal pricing must be addressed and approach the economic value of gas to a higher degree. Based on these main findings we draw the following recommendations drawn up in the figure below.

Figure 4: A stepwise approach to a bottom-up development of regional trade

1 DOMESTIC MARKET

#1 : Provide legal and regulatory framework for transparent third party access to idle infrastructure
#2: Reduce flaring of gas by providing incentives for flaring reductions
#3: Follow up on renewable energy commitments from COP22 in Marrakech
#4 &5: Introduce social protection programs for the poor and communicate reforms before phasing out of subsidies for natural gas
#7: Strengthen security of supply and market development by usage of underground gas storages

2 ENERGY HUB

#6: Pricing models should be simple and benefit both parties

#8: Reduce risk and risk premium by usage of offshore pipelines or LNG import

#9: Neutralize origin of gas – by use of hubs

3 (SUB) REGIONAL TRADE

#10: Develop the integration of gas markets step wise over time based on technical, economic and commercial viable gas pipeline projects

#11: Develop a transparency platform with monthly and daily data on gas trade and flows.

#12: Use elements of the EU market model on sub regional levels

MAIN FINDING #1: GLOBAL OIL AND GAS PRICES IMPACT THE POSSIBILITY FOR REGIONAL GAS TRADE

The unpredictability of global oil and gas prices is impacting the possibility for regional gas trade and not least the balance between trade within the region and towards the global gas market. All indicators point towards a major supply glut in gas and LNG across the world. The 4 major players - the US, Qatar, Russia, and Australia are all expected to bring new volumes to the world market within the next couple of years. Both Australia and the US have already made the investments into new LNG export capacity, Qatar has recently announced that it will increase production from the North Field, and Russia has captured market shares in the EU by increasing supplies through its pipeline system; they have also stated an intention to become the world's largest LNG exporter. Finally there is Iran, which has the potential to join the club of great gas producers as they hold the second largest reserves in the world.

On the demand side, there is lower than anticipated demand for gas in Europe and Asia following tough price competition from coal, renewable and the re-emergence of nuclear production in Japan. Any slump in growth will hit gas because it is often the marginal fuel. In addition the continuing low oil price environment may extend several years and add to the low price levels of gas in the short to medium term.

Thus the expectation is that markets are converging to differences in transportation costs and that gas prices in the short to medium term will be lower than prices were in the years preceding 2015. The implications of such a price environment for the MENA region is that trade projects that were not previously attractive to Governments in the Middle East could be more feasible since exporting gas is becoming less profitable, while consumption of gas is becoming more attractive due to the price development.

The utilized gas prices, resulting from the expected global demand and supply balance, are presented in Table 1 (below).

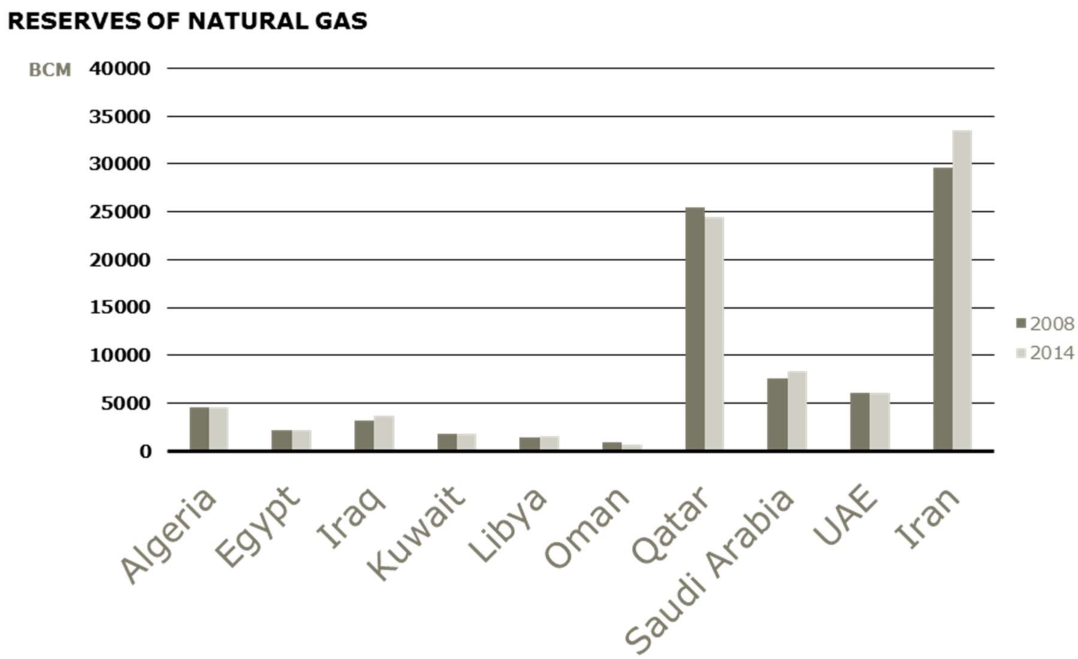
Table 1: International gas prices (real)

(USD(2016)/MMBTu)	Europe	US	Asia
2016-2020	5	3	6
2021- 2025	6	4	7
2026-2030	7	5	8

MAIN FINDING #2: SURPLUS GAS RESERVES AND POTENTIAL PRODUCTION EXIST IN QATAR, IRAN, AND ALGERIA

The MENA region has some of the world's largest gas reserves and this is fundamental for trade between the countries. Figure 5 (below) illustrates the division of reserves within the region revealing that Iran, Qatar, Algeria, Saudi Arabia, and UAE to be the largest reserve holders.

Figure 5: Reserves of natural gas MENA countries and Iran



Source: OAPEC & BP

However, consumption and the cost of extracting the resources differ between countries. Our analyses of reserves and actual fields, production possibilities and indigenous consumption show that the main candidates for increasing export in the region are Qatar, Iran, and Algeria. UAE and Saudi Arabia both have large reserves but the high costs of extracting and increasing local consumption mean that production is likely to be used for the domestic market. In the long run, Iraq and Libya could potentially also be candidates but ongoing conflicts make it impossible to judge the likelihood at present. On the regional scene, a high level of activity is recorded in the Eastern Mediterranean and could increase the utilisation of existing infrastructure and the supply to neighbouring countries.

In Qatar, production has been restrained by a politically driven moratorium on gas production that has been in place for more than 10 years. In April 2017 it was announced that production in the North Field is being increased in order to export additional gas from the field, in total 20 bcm per year, and estimates by the IEA suggest that up to 70 bcm could be supplied in the medium term. As of June 2017, there have been no indications that the LNG and pipeline exports out of Qatar will be directly influenced by sanctions from the Arab neighbours.

Iran has been holding back on gas production due to the international embargo, which has even stopped export to Turkey. With the lifting of the embargo, it is likely that Iran will increase production. Domestic gas demand in Iran could increase in the short term and along with the current export commitments dampen the short term availability of gas for export in Iran.

Algeria has large reserves and could potentially increase production although several studies are sceptical with regard to this. Civil unrest and terrorism have contributed to high costs, as have the long distances associated with field developments.

In previous studies Libya has been seen as a candidate for export within the region. However, due to the unrest and safety concerns, development has been set back several years. Iraq has potential but must first satisfy the domestic markets before large-scale export can take place.

Table 2 below provides an overview of the derived gas balances from 2015 to 2030. Import and export is derived from known infrastructure and commitments. Any excess or shortfall from this is presented in Table 3.

Table 2: Future Gas Balances bcm/y

bcm/y	Production (P)				Consumption (C)				Import (I)				Export (E)			
	'15	*'20*	*'25*	*'30*	*'15*	*'20*	*'25*	*'30*	*'15*	*'20*	*'25*	*'30*	*'15*	*'20*	*'25*	*'30*
Algeria	88	100	104	94	41	45	50	59	0	0	0	0	44	44	44	44
Bahrain	15	23	21	20	15	19	21	23	0	4	4	4	0	0	0	0
Egypt	44	75	76	70	48	64	72	90	4	0	0	0	0	0	0	0
Iraq	9	21	31	34	9	23	34	51	0	24	24	24	0	0	0	0
Jordan	0	0	0	0	2	3	3	3	2	8	8	8	0	0	0	0
Kuwait	17	17	22	28	22	25	28	31	5	8	15	15	0	0	0	0
Lebanon	0	0	0	0	0	0	2	2	0	2	2	2	0	0	0	0
Libya	13	17	20	25	8	20	23	25	0	0	0	0	5	0	0	0
Morocco	0	0	0	0	1	1	5	5	1	1	5	5	0	0	0	0
Oman	31	36	36	32	22	23	25	30	2	2	2	2	10	10	10	0
Qatar	191	209	259	259	48	48	50	50	0	0	0	0	129	137	137	137
KSA	104	132	132	132	104	107	124	140	0	0	0	0	0	0	0	0
Syria	2	2	10	10	2	2	10	20	0	1	1	1	0	0	0	0
Tunisia	2	4	4	3	5	7	6	5	3	2	2	2	0	0	0	0
UAE	59	52	42	35	71	66	71	75	23	38	34	29	8	8	8	8
Yemen	3	10	15	20	1	5	10	15					2	9	9	9
Iran	182	199	351	351	184	206	228	250	7	7	7	7	9	29	29	29
Total	88	100	104	94	41	45	50	59	0	0	0	0	44	44	44	44

Sources: See country chapters

Table 3: Availability of gas and self-sufficiency bcm/y

bcm/y	Availability of gas (P-C+I-E)				Self-sufficiency (P-C)			
	2015	*2020*	*2025*	*2030*	*2015*	*2020*	*2025*	*2030*
Algeria	3	11	10	-9	47	55	54	35
Bahrain	0	8	5	1	0	4	1	-3
Egypt	0	12	4	-19	-4	12	4	-19
Iraq	0	22	21	6	0	-2	-3	-18
Jordan	0	5	5	5	-2	-3	-3	-3
Kuwait	0	0	9	12	-5	-8	-6	-3
Lebanon	0	2	0	0	0	0	-2	-2
Libya	0	-3	-3	-1	5	-3	-3	-1
Morocco	0	0	0	0	-1	-1	-5	-5
Oman	0	5	3	4	9	13	11	2
Qatar	14	24	72	71	143	161	209	209

KSA	0	26	8	-8	0	26	8	-8
Syria	0	1	1	-9	0	0	0	-10
Tunisia	0	0	0	0	-3	-2	-2	-2
UAE	3	16	-2	-19	-12	-14	-28	-40
Yemen	0	-4	-4	-4	2	5	5	5
Iran	-4	-29	101	79	-2	-7	123	101
Total	17	95	230	111	176	234	362	237

Source: See country Chapters

We conclude that both regulatory incentives and infrastructure investments can contribute to an even higher availability of gas in the region at low costs. Our recommendations for an increased availability of gas are:

RECOMMENDATION #1: UTILIZATION OF IDLE INFRASTRUCTURE: A STEPPING STONE FOR REGIONAL GAS TRADE

Idle or underutilized gas infrastructure which includes the LNG terminals in Egypt, UAE and Oman,the gas pipelines from Algeria to Europe and the Arab pipeline from Egypt to Syria, are strong opportunities for increased trade at low costs.

Countries with such idle infrastructure can be used as stepping stones for export outside and within the region and hence also for regional trade. The most obvious example is the development of Egypt to a gas hub using the existing idle LNG export terminals and reversing the gas flow in the Arab pipeline by connecting to Iraq. This would require simultaneously importing gas from the East Mediterranean gas fields. LNG export terminals in UAE and Oman can be used for export of gas from Qatar or potentially from Iran. The Algeria to Europe gas pipelines can be used for export to Morocco and Tunisia, but in the longer term, also for gas transit from outside the region such as the Trans Saharan Gas Pipeline. In several circumstances the idle infrastructure is owned by private investors and may thus not be open for third-party access. Therfore we recommend that the necessary conditions for access are clearly specified in the relevant secondary legislation (grid codes) to avoid the establishment of technical and financial barriers to the usage of the facilities. LNG export facilities for example do not seem to be mentioned in the draft primary gas market law in Egypt.

RECOMMENDATION #2: REDUCE FLARING OF GAS BY PROVIDING INCENTIVES AND REQUIREMENTS FOR FLARING REDUCTIONS – POTENTIAL FOR UP TO 50 BCM OF SAVINGS PER YEAR WHICH COULD BE TRADED AND CONSUMED IN THE REGION

Flaring of gas is still taking place in many countries and can be an additional source of gas for increased trade if collected and marketed. In 2015, around 50 bcm of associated gas was flared in the MENA region. The estimates for top flaring countries were: Iraq: 16.2 bcm, Iran 12.1 bcm, Algeria 9.1 bcm, Egypt 2.8 bcm, Libya 2.6 bcm, Qatar 1.1 bcm, UAE 1.0 bcm, and Kuwait 0.9 bcm and the trend is increasing in Algeria, Egypt and Iraq. Several of these countries are among the large producers of both oil and would have an upside in using the gas for power production and exporting the oil instead. These volumes present a significant source of gas that could be utilized domestically, replacing fuel oil and gas oil in power generation (e.g. Iraq), in the domestic sector (e.g., Iran, Algeria and Egypt) or for export. A combination of the following measures is essential to achieve significant reduction in flaring and venting[1]:

1. Clarify Oil & gas legislation on the treatment of associated gas
2. Introduce petroleum fiscal terms that will encourage associated gas utilization investments
3. Ensure that gas market policies encourage and enable associated gas utilization: This includes allowing oil & gas companies the right to monetize gas, open and non-discriminatory access to infrastructure and market-based energy pricing
4. Ensure the regulation of flare and venting is transparent with effective monitoring and enforcement
5. Establish a comprehensive and methodical approach to address legacy flaring and venting, such as establishing a realistic flare/vent-out deadline
6. Include provisions for associated gas utilization in new oil developments
7. Develop an integrated plan for the country for both associated and non-associated gas

RECOMMENDATION #3: CONTINUED COMMITMENT ON THE RENEWABLE ENERGY TARGETS FROM COP22 IN MARAKECH REDUCE LIQUID FUEL CONSUMPTION DURING PEAK HOURS AND INCREASE AVAILABILITY OF GAS FOR TRADE

In addition to the obvious benefits from a reduction in gas flaring (which have been discussed for years through the Global Gas Flaring Reduction initiative), there may also be significant benefits in investing in and committing to the targets from the COP22 meeting held in Marakechin 2016. Implementing renewable energy in the power generation mix will free up oil and gas which would otherwise have been burned in power generation to meet the daily peaks. In particular.solar energy is well suited to cover peak daily demand.

Gas pricing and subsidies for gas remains an issue which needs to be addressed and the above initiatives are reliant on a development towards transparent and unsubsidized prices of energy. For example subsidized fossil fuels for power generation could be a barrier for introduction of renewable energy sources.

MAIN FINDING #3: SUBSIDIES DO STILL DISCOURAGE INVESTMENTS IN PRODUCTION – ALTHOUGH PROGRESS RECORDED IN SOME COUNTRIES

When it comes to subsidies there is no size fits all – each country is phased with its own history , endowments of resources and political and social environment. Thus reforms initiated within this area will happen in different tempi. However, there is a movement led by Egypt and Iran in the MENA region towards reducing energy subsidies to reduce the fiscal burden on government budgets and to take advantage of the low oil and gas prices to phase out subsidies, in particular for petroleum products that carry the heaviest burden on government budgets. In Table 4 (below) the identified subsidy removal programs over time are presented.

Table 4: Subsidy removal programs over time

	Subsidy removal programs for gas		Elimination	Financial gas price	Projected prices based on today's reforms		
	Efforts to	Target level	Target	USD/MMBtu	2020	2025	2030

[1] GGFR: Guidance on Upstream Flaring and Venting. Policy and Regulation, 2009.

	date	of subsidies	date				
Algeria	Minimal	no	no	0.5 - 0.6	0.5 - 0.6	0.5 - 0.6	0.5 - 0.6
Morocco	Not subsidized			reg/int.	reg/int.	reg/int.	reg/int.
Tunisia	Planned	no	no				
Egypt	Initial increases in 2014, but halted	Originally 100% reduction , now 70%	2019	ind. 3-8, HH 1.7-6			ind. 3-8, HH 1.7-6
Jordan	Not subsidized			6 (import price)	import price	import price	import price
Lebanon	Not subsidized			5 (import price)	import price	import price	import price
Iran	On hold, but Further increases in 2015	90 percent of international prices	2015 (not met)	2	90% of Int.	90% of Int.	90% of Int.
Iraq	Minimal	no	no				
Kuwait	Minimal	no	no	1,5	1,5	1,5	1,5
Bahrain	Not subsidized	n.a.	2021	2,5	3,5	4	4
UAE	None	no	no	1.25-1.30			
Saudi Arabia	Gas price increased recently	committee decides	over 5 years	1.25-1.50	cost rec?		
Qatar	None	committee decides	no	0,75	0,75	0,75	0,75
Oman	Not subsidized			3	market price	market price	market price
Yemen	None	no	no				

Source: Subsidy chapter

In many countries the reduction in petroleum product subsides has been combined with the introduction of an automatic adjustment of petroleum prices (weekly, monthly or quarterly), so that the effort is not eroded by a return to a higher international oil price level. However, electricity prices are still low in most countries in the region, meaning that power utilities either need low gas prices or budget transfers from the government to be financially sound. MENA countries fall into three groups with regards to impact of subsidies on trade:

Table 5: Groups of countries with respect to subsidies

Category	Barriers to future trade
(Potential) gas importers with small indigenous production	No barriers for (future) trade
Gas exporters/importers with large reserves. Domestic gas prices significantly below the international benchmark	Discourage investment in production for domestic market. Barrier for (future)trade
Gas importers at market price with indigenous production sold below international benchmark prices	Discourage investment in production and for domestic market Limited barrier for (future(trade

Source: Ramboll

- Gas importing (or soon to be importing) countries Morocco, Jordan, Lebanon, with small or negligible indigenous gas production, are importing gas at international/regional prices for power generation. These countries have minimal or no gas subsidies that would pose a barrier for future gas trade. They have also removed petroleum product subsidies, but still have low electricity prices that require explicit transfers to the power utility. This is not sustainable and poses a threat to the budget.

- Algeria, Egypt, Libya, Iran, Iraq, Saudi Arabia, Qatar with large gas reserves, export gas (or with a potential to export gas) and domestic gas prices below the international benchmark (i.e., a subsidy measured by the price gap method). This could discourage investments in E&P and the expansion of gas production and could pose a barrier for future gas trade, particularly if there is a risk that production is diverted to the domestic market where gas prices are low. These countries have begun the removal of petroleum product subsidies but this is on hold in several countries. They have a long way to go before reaching international levels and none of these countries have an automatic adjustment of fuel prices. With the exception of Saudi Arabia, theyalso have low electricity prices, thereby putting a constraint on government finances and foreign exchange reserves.

- Oman, Kuwait, UAE, Tunisia and soon Bahrain fall in between these two groups; they are importing gas at international/regional prices, and have indigenous domestic gas production (Oman and Abu Dhabi also export LNG). Gas prices are below the international benchmark in Kuwait, UAE and Tunisia, and this could discourage investments in new gas domestic production but would not be a barrier to gas trade provided it is based on international fuel prices. Only Oman and UAE have eliminated petroleum product subsidies and in Oman gas prices have reached an international level. With the exception of UAE, electricity prices are low.

International experience shows that to phase out subsidies a number of effective initiatives need to be launched. While a toolbox of tested initiatives is available, the important thing is to realize that these initiatives cannot stand alone. The following initiatives are recommended to be planned in advance of any phase out of subsidies.

RECOMMENDATION #4: INTRODUCE SOCIAL PROTECTION PROGRAMS FOR THE POOR BEFORE PHASING OUT OF SUBSIDIES FOR NATURAL GAS

The case studies show that the most successful reforms to reduce or eliminate energy subsidies have been in countries where the reduction of subsidies was done in parallel with the introduction of an increase in social protection for the poor in order to compensate for the tariff adjustments.

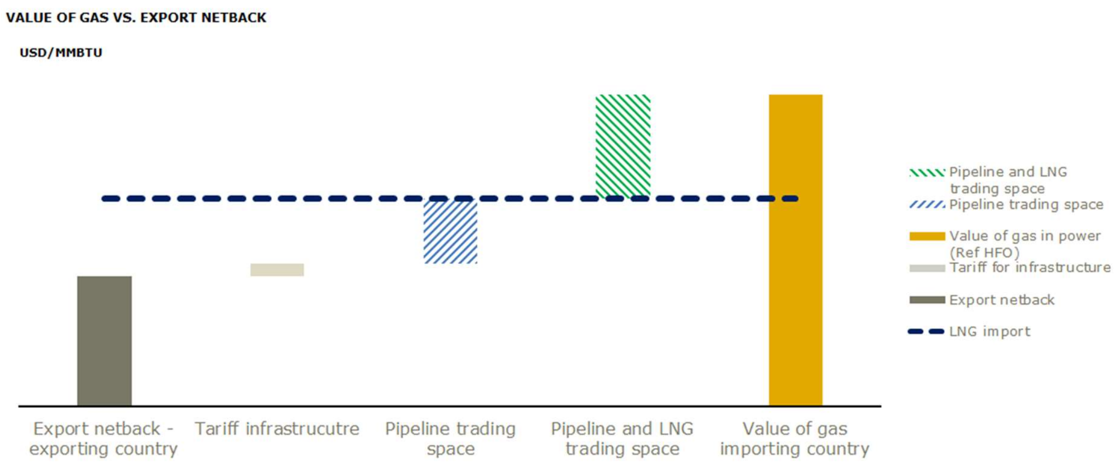
RECOMMENDATION #5: COMMUNICATE SUBSIDY REFORMS, PRIOR, DURING, AND POST POLICY INTERVENTION AND FOCUS ON SERVICES IMPROVEMENTS AND STABLE ENERGY SUPPLY.

Additionally, the governments who successfully implemented subsidy reforms communicated cleary the needs for reform in order to create trust and credibility in the policy changes. If successful, increasing prices will give rise to a number of possibilities for trade within the region. To illustrate this we investigated the value of gas within the power sector. The most effective and sustainable subsidy reforms are in countries where the population see service improvements, such as more reliable energy supply. We thus recommend that quick wins and benefits are brought to the attention of the population in communication campaigns and perceived improvements in reliability of supply.

MAIN FINDING #4: VALUE OF GAS IS HIGHER THAN THE LNG IMPORT PRICE AND HIGHER THAN THE VALUE OF EXPORTING THE GAS. THIS ENABLES ROOM FOR WIN-WIN SITUATIONS FOR PRODUCERS AND CONSUMERS FROM CROSS BORDER PROJECTS.

A fundamental question for this study is whether there is a trading space, defined as the area where both sellers and buyers are better off from trading, i.e. sellers receive higher netbacks than from exporting out of the region and buyers spend less on fuel than they would otherwise have done.

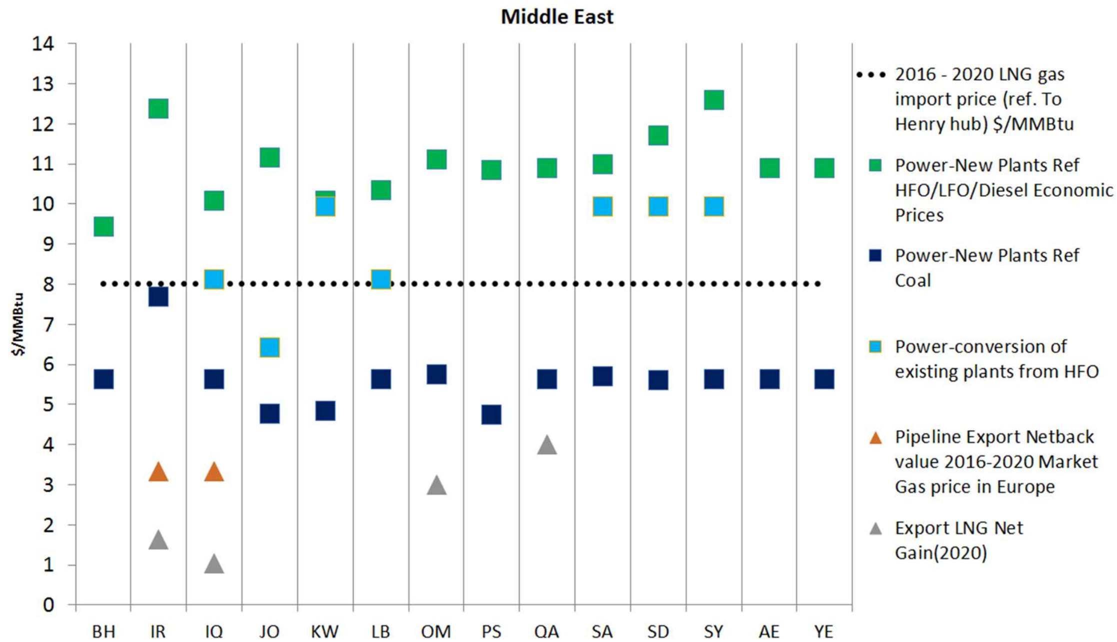
Figure 6: Value of gas vs. export netback



Source: Ramboll

This trading space is derived for each country, comparing the netback from export to world markets and the value of consuming gas in the power sector compared to using coal and HFO. The value of gas in the power sector is the value which makes the buyer indifferent between the competing fuel, taking into account capital costs, O&M, and efficiencies. Netback of gas for export has been divided into pipeline and LNG under the assumption that liquefaction costs are sunk for the facilities already constructed and up and running. Figure 7 plots the derived values of gas in the power sector against the netbacks of exporting gas out of the region. It shows that whenever the alternative is HFO (existing or new) for power generation, the value of gas to the buyer is always above the sellers' netback from export, leaving a positive trading space. Thus most countries should be willing to pay more than the LNG import price for a power plant converting from HFO to gas. If we consider coal as the reference, the trading space narrows significantly for most countries.

Figure 7: Netback value of gas in export (LNG+Pipeline), power sector (coal, HFO) ME



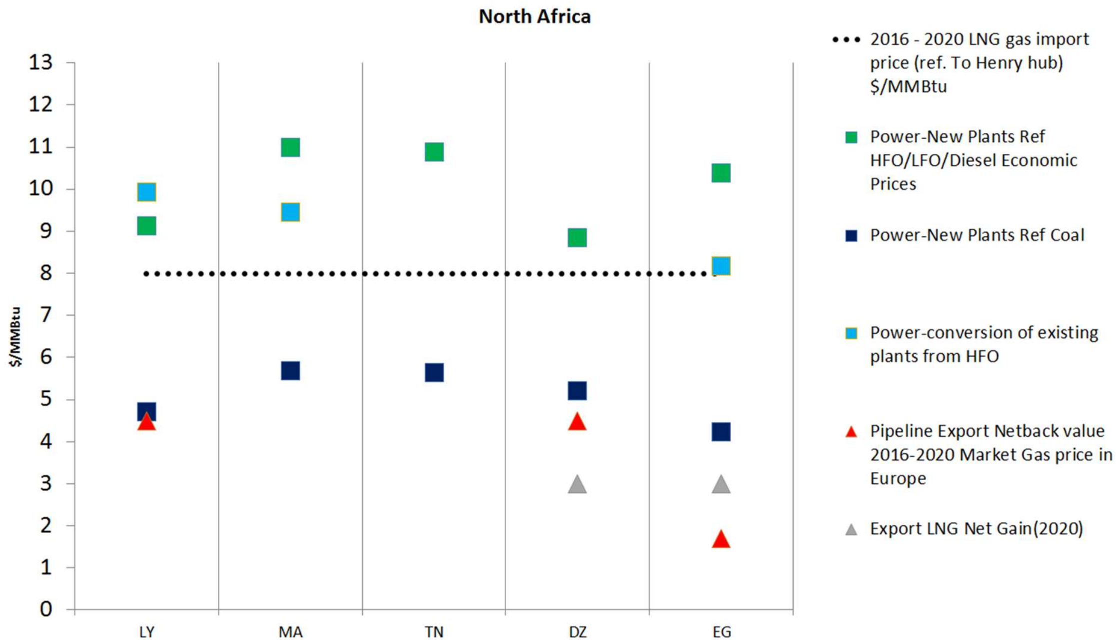
Source: Calculations of values of gas and netbacks, chapter 10

The trading space identified give life to a number of bilateral projects such as:

- Iran and practicality all of their neighbour countries. Netbacks from exports out of the region are not very high – more value could be extracted by trading with the neighbouring countries in need of gas. In addition, engaging in regional/local trade will be less risky and capital intensive than constructing large scale export infrastructure projects to reach world markets.
- Iraq too will have a relatively low value from exports to world markets. The priority here should be to satisfy own demand either by trading with its neighbours (such as Iran) or by increasing production capacity. This may take a long time.
- Qatar – Saudi Arabia. With the high value of gas in Saudi Arabia for both converting and establishing new power plants based on gas exist, combined with a netback of 4 USD/MMBTU from LNG export from Qatar to Europe, it should be possible to work out a mutually beneficial agreement where both parties win. The same argument applies to Bahrain and Qatar.

The same picture and general conclusion is reached for North Africa illustrated below in Figure 8.

Figure 8: Netback value of gas in export (LNG+Pipeline), power sector (coal, HFO) NA



Source: Calculations of values of gas and netbacks, chapter 10

The trading space identified give life to a number of bilateral projects such as:

- Morocco-Algeria where the alternative to import of LNG is the import of gas from Algeria. Algeria enjoys netbacks of around 3-4 USD/MMBTU. Morocco however should be willing to pay up to 6 USD/MMBTU, compared to the alternative coal solution. Transportation costs between the two countries is minimal as pipelines already exist, assuming 0.25 USD/MMBTU. Distribution of the net gain should be a matter of negotiation between the countries – but remains a net gain for the region.
- In principle the same could be true in Tunisia where import from Libya could make sense given the high value of gas in Tunisia and the low netback from export for Libya.

To enhance the trading space we recommend that:

RECOMMENDATION #6: PRICING MODELS SHOULD BE SIMPLE AND BENEFIT BOTH PARTIES – VALUE SHOULD BE DISTRIBUTED FAIRLY

Both sellers and buyers must be significantly better off from trade. The identified trading space is a simple example showing that there could be area where both sellers and buyers are better off. The division of this area between the trading parties is to be agreed in the gas sales and purchase agreements and would, due to the difference between countries, differ from country to country. However it is advisable that floor (for example the selling country's alternative netback from export to Europe/Asia) and ceiling prices (a basket of the most relevant alternative fuels for the buyer country, or even better hub prices that better reflect the global and regional supply and demand balance) are determined and agreed upon to secure both parties. In addition, ensuring that the prices can be renegotiated with frequent intervals could reduce the transaction risk.

The second angle on Figure 8 is that countries with gas available should seek to satisfy their own demand before thinking of exporting. However what is seen in the region is that countries endowed with limited resources of gas would rather seek to maximize these resources rather than trading with neighbouring countries.

MAIN FINDING#5: POLITICAL AND VIOLENT CONFLICTS, AND EMBARGOES ARE MAJOR BARRIERS TO TRADE

Political conflicts, including embargos, are the main barriers for gas trade in the region. In particular, the international embargos of Iran, Iraq and Libya have historically played a role in delaying or stopping projects. The following political conflicts have been identified:

- Long-lasting differences in viewpoints between Algeria and Morocco have been a barrier to increased trade.
- Qatar – Saudi Arabia. Disagreements prevented the North Dolphin pipeline from Qatar to Kuwait. Disagreements may also prevent direct connections between the two countries.
- Iraq-Kuwait. Although a pre-war pipeline exists, no intentions of using it have been identified.

Domestic political conflicts, defined as events and barriers within a country have been identified:

- Libya - mainly threatening an onshore connection between Tunisia and Libya
- Yemen civil war - internal political conflicts preventing full utilization of resources
- Syria civil war - preventing offtake from the Arab Gas Pipeline
- Iraq – conflict in the north and west prevents potential projects from maturing

Obvious trading possibilities have been made impossible and more importantly, the use of some of these countries for transit has been delayed or made impossible.

MAIN FINDING #6: DUE TO LACK OF TRUST BETWEEN COUNTRIES, COUNTRIES ARE WILLING TO PAY A PREMIUM ON SECURITY OF SUPPLY

Despite the difference in production costs and availability of gas, there is a clear tendency to favour national production rather than trade gas via pipelines. Instead, flexible FSRU terminals are used to cover peak load and short term deficits. With transport unit costs of LNG being higher than pipelines, this development indicates that the market is willing to pay a security of supply premium for the diversification that LNG offers. FSRUs should thus not be seen as a barrier but rather as a symptom of the risk which pipelines are perceived to carry. Examples of such developments have been seen in Egypt, Kuwait, Jordan, and UAE.

We suggest the following measures to be implemented in order to de-risk trade between countries:

RECOMMENDATION #7: USE UNDERGROUND GAS STORAGES AS A MEASURE TO REDUCE THE RISK OF TRADE AND PROMOTE TRADE

We recommend that countries investigate the potential for underground gas storages. Underground gas storages increase security of supply and could lower the risk premium which is currently attached to import of gas from neighbouring countries. It may be easier for countries to rely or partly rely on supply from neighbouring countries if they have domestic gas storage available. Specifically for the region, security of supply close to demand centres could be relevant in for example Algeria, with many new fields located many kilometres from the coastal demand. Underground gas storages in Saudi Arabia could also make sense as many of the future gas fired power plants are located in the western part of the country while much of the production is in the east. From a purely security of supply perspective, underground gas storages could make sense in Morocco and Tunisia, From a hub perspective, it would make sense to have gas storage in Egypt to support their aspirations to become a trading hub for the region, this is also the case for UAE.

RECOMMENDATION #8: CONSIDER OFFSHORE PIPELINES OR LNG IMPORT TO REDUCE TRANSACTION RISKS AND INCREASE DIVERSITY OF SOURCES

A number of cases exist where the risk of disruption is not only political but also related to terrorism and sabotage of pipelines onshore within or between countries. Thus we recommend considering offshore pipelines, as an alternative to onshore pipelines, whenever possible. This approach could be applied between Libya and Tunisia, Qatar and Kuwait, and Egypt and Libya. Additionally, FSRUs offer the possibility of establishing a LNG chain for import at relatively short notice and over the past couple of years this has been shown to be the most practical way of enhancing trade between countries and to enhance diversity of sources. The two options lower the transaction risk between countries and allow gas to find markets without the added risk of transit.

RECOMMENDATION #9: PURSUE HUB DEVELOPMENT, WHICH CAN EVOLVE IN DIFFERENT TEMPI, TO NEUTRALIZE ORIGIN OF GAS

As one barrier is the origin of gas, it should be considered whether gas could be sent via a third country which would serve as a hub and allow bypassing of conflicts. This method has been used successfully in Europe where the origin of gas is becoming less clear. An example could be to ensure that contractually at least, gas could flow from Spain to Morocco and from Italy to Tunisia. The development of hubs would most realistically start out with domestic gas and existing pipeline supplies blending with LNG from the world market. Hubs would reduce the barriers for pipelines by characterising cross border supplies between countries as supplies to hub instead of the traditional bilateral characterisation.

Table 6: Proposal for hubs

Sub-region	Countries	Hub	External connections
Maghreb	Morocco, Algeria, Tunisia, (Libya)	Algeria	Italy, Spain, (Nigeria (TSGP))
Libya	Libya, Tunisia	Libya	Italy
East Mediterranean	Egypt, Syria, Iraq, Jordan, Lebanon, Palestine, (Cyprus, Israel)	Egypt	Turkey
Gulf	Qatar, UAE, Oman, Bahrain, Kuwait	Qatar/UAE	(India)
Arabic Peninsula	Saudi Arabia	Saudi Arabia	
Iran	Iran, UAE, Oman, Iraq	Iran	Turkey, Turkmenistan, (Pakistan)
Iraq, Iran, Syria	Iraq, Iran, Syria	Iraq	Turkey

At a later stage these sub-regions can be connected via long, large diameter interconnectors provided that the basic incentives in terms of supply and demand are present.

MAIN FINDING #7: NO SINGLE TRADE MODEL CAN AT PRESENT BE USED FOR THE MENA REGION

Different models for regional gas trade have been developed in different regions of the world. The push for more competitive gas markets and lower prices began with the deregulation of the US gas market and the introduction of gas-to-gas competition in the 1980's. In Europe, a move towards competition started in sub-regions, after each country had developed their own gas markets, which were later connected. The UK introduced third-party access to pipelines in 1986 to increase competition. The development of the EU gas market integration was based on this model.

The EU internal market for gas was developed over decades to achieve lower prices for consumers by increased competition. This was done though directives to the member countries using supra-national powers mandating regulated TPA, unbundling of transmission and reinforcing independent regulation to open the gas market. This included mandating investments in sufficient cross-border capacity to integrate the European transmission infrastructure so gas could circulate freely from one point to another. Moreover, the experience in the EU was that lack of transparency was a major obstacle for increasing gas trade between buyers and sellers in different countries. This was the reason for creation of the EU transparency platform, which gives access to daily capacity and flow on border points.

In most MENA countries, gas is supplied by state-owned companies at government-set prices and gas buyers are relatively few, and in many cases also state-owned companies. The relatively few gas interconnections and pipelines between countries are based on government to government negotiated gas contracts [e.g., Dolphin, Arab Gas Pipeline, GME, TransMed] and the regional institutions, Maghreb, Mashreqand GCC, have no power or mandate to push gas trade or competition. The development of more mature gas markets in each MENA country, the achievement of international benchmarks for gas prices and the introduction of more sellers and buyers are precursors for attracting investments in production, pipelines and interconnections. The move towards LNG imports in many MENA countries is a step in the right direction as it increases the gas supply options at international prices and forces the government to revise the gas pricing policy or bear the financial burden. The establishment of Gas Hubs in the region will also contribute to this development.

RECOMMENDATION #10: DEVELOP THE INTEGRATION OF GAS MARKETS STEP WISE OVER TIME BASED ON TECHNICAL, ECONOMIC AND COMMERCIAL VIABLE GAS PIPELINE PROJECTS

Ensure aligned economic interests between the exporting and the importing countries. New pipeline projects will link countries, increase the number of supply options and grow gas markets into maturity. By increasing gas prices to international levels and allowing more sellers and buyers of gas, including LNG trade, gas markets will move towards more competition and attracting investments in pipelines and interconnections. Again to support price formation and competition, third party access to infrastructure is crucial. In parallel it will be important that gas is made available for third parties (shippers) as well. Inthe EU this has been done through gas release auctions which could be considered an option.

RECOMMENDATION #11: DEVELOP TRANSPARENCY PLATFORM ACROSS THE MENA REGION

There is limited access to data on the gas sector in the MENA region. Different organisations have data on reserves, which are most often having the same source and are published only once a year. There is no daily or monthly data available on gas flow and gas trade. The experience from the single gas market in EU was that lack of transparency was a major obstacle for gas trade and thiswas the reason for the creation of the EU transparency platform, providing access to daily capacity and flow on border points. There are at present 4 entry points to the EU from the MENA region from Morocco, Algeria, Tunisia and Libya respectively.

It is recommended establishing a transparency platform between the MENA countries. As there is no daily or monthly data available on gas flow and gas trade in the region, efforts should made to collect and publish such data to increase transparency and display gas trade opportunities.

RECOMMENDATION #12: EU SINGLE MARKET MODEL FOR GAS COULD BE USED IN MENA COUNTRIES CLOSE TO EU, EGYPT AND ALGERIA, TUNISIA AND MOROCCO

The EU single market model for gas includes the unbundling of gas transmission, distribution and storage from supply and production in order to create third party access to most infrastructure. These elements have gradually been developed over more than 20 years, most recently with the so-called 'Third Energy Package'. The model, which was initially started in 1998 with the opening of the market for large industrial consumers, has gradually been expanded to all consumers and more and more countries have entered into the market in line with EU enlargement, as well as neighbouring countries like Ukraine. This shows that the market is scalable. Egypt is at present implementing a new gas law which allows third party access to the gas transmission system.

Algeria, Tunisia, Morocco and Libya could also adapt the EU gas market model, although experience shows that it may take many years to achieve this. This would open up for reverse flow from Spain to Morocco, and from Italy to Tunisia and Libya respectively and hereby create a virtual connection for trade.

3. EXISTING TRADE

3.1 Existing gas infrastructure in place among MENA countries

As this study focuses on the lack of gas infrastructure and trade among the MENA countries, it is important to examine the state of existing infrastructure. A list of the main existing gas infrastructure between countries is presented below, and in chapter 11 we will go into much more details on the Arab Gas Pipeline and the Dolphin Pipeline.

- The Arab Gas Pipeline exporting gas from Egypt to Jordan, Syria and Lebanon (through a swap arrangement) has been exposed to several terrorist attacks and a devastating war in Syria leaving the current technical operational status unknown; Combined with gas supply shortages in Egypt trade has been halted.
- The connection between Algeria and Morocco: Morocco receives gas transit royalty of 7% for pipeline transit to Spain and purchased additional gas from 2011 for the power utility ONEE amounting to 634 mcm/.Further increases in gas export from Algeria to Morocco could take place by extending the pipeline capacity by adding new compressors, but political disagreements and security of supply has forced Morocco to consider investing in a LNG import terminal.
- Algeria – Tunisia is used but primarily for exports to Italy, and the resulting in kind gas accruing to Tunisia in the range of 5.25-6.5% .
- The Dolphin pipeline between Qatar, UAE, and Oman is one of the most used pipelines the region. As of 6th of October 2016 Qatar has announced that additional quantities are to be delivered to UAE. This agreement followed an upgrade of the compression facilities at Ras Laffan where 3 new compressor units were added last year.
- Iran-Iraq is the newest constructed/rehabilitated pipeline supplying power plants around Baghdad. Additional plans exist to expand the pipeline further and supply more power plants in Iraq. However, the gas has not yet started flowing.
- Additionally several LNG "interconnections" are possible – exporting LNG from the producers Algeria and Qatar to countries with permanent or temporary LNG import infrastructure. These countries are Morocco (2020-2025), Jordan (FSRU), UAE (FSRU), Kuwait (FSRU + landbased), Bahrain (2018/2019), Egypt (FSRU).

The following tables show the interconnections among the MENA countries both in terms of pipeline and LNG. It is assumed that in principle gas could go both ways in the pipelines, which from a trade perspective is reasonable as backhaul possibilities exist. On the other hand, we assume one way transport for LNG. It is important to note that only a fraction of these possibilities are actually actively being used for trade among the Arab and other Middle East countries.

Table 7: Existing or FID pipelines and LNG (import/export terminals) among MENA countries

o

From	MOR	ALG	TUN	LIB	EGY	JOR	SYR	PAL	LEB	IRA	KSA	KUW	BAH	QAR	UAE	OMA	YEM	IR
MOR		E	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
ALG	E		E	N	LNG	LNG	N	N	N	N	N	LNG	N	N	LNG	N	N	N
TUN	N	E		N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
LIB	N	N	N		LNG	LNG	N	N	N	N	N	LNG	N	N	LNG	N	N	N
EGY	N	N	N	N		LNG	E	N	N	N	N	LNG	N	N	LNG	N	N	N
JOR	N	N	N	N	E		E	N	N	N	N	N	N	N	N	N	N	N
SYR	N	N	N	N	E	E		N	E	N	N	N	N	N	N	N	N	N
PAL	N	N	N	N	N	N	N		N	N	N	N	N	N	N	N	N	N
LEB	N	N	N	N	N	N	E	N		N	N	N	N	N	N	N	N	N
IRA	N	N	N	N	N	N	N	N	N		N	N	N	N	N	N	N	E

	MOR	ALG	TUN	LIB	EGY	JOR	SYR	PAL	LEB	IRA	KSA	KUW	BAH	QAR	UAE	OMA	YEM	IRAN
KSA	N	N	N	N	N	N	N	N	N	N		N	N	N	N	N	N	N
KUW	N	N	N	N	N	N	N	N	N	N	N		N	N	N	N	N	N
BAH	N	N	N	N	N	N	N	N	N	N	N	N		N	N	N	N	N
QAR	N	N	N	N	LNG	LNG	N	N	N	N	N	LNG	N		E	N	N	N
UAE	N	N	N	N	LNG	LNG	N	N	N	N	N	LNG	N	E		E	N	N
OMA	N	N	N	N	LNG	LNG	N	N	N	N	N	LNG	N	N	E		N	N
YEM	N	N	N	N	LNG	LNG	N	N	N	N	N	LNG	N	N	LNG	N		N
IR	N	N	N	N	N	N	N	N	N	E	N	N	N	N	N	N	N	

Legend: E=Existing Pipeline. LNG=Possibility for trade with LNG.

3.2 Potential gas interconnections pipeline

In principle, a large number of potential connections could be built if we add potential interconnections (defined as connections between countries that border each other, onshore as well as offshore), and ignore political and resource constraints. We have chosen not to add LNG opportunities in table 2, because almost each and every country in the region could in principle invest in an LNG receiving terminal.

Table 8: Potential physical connections

To

From	MOR	ALG	TUN	LIB	EGY	JOR	SYR	PAL	LEB	IRA	KSA	KUW	BAH	QAR	UAE	OMA	YEM	IRAN
MOR		E	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
ALG	E		E	P	N	N	N	N	N	N	N	N	N	N	N	N	N	N
TUN	N	E		P	N	N	N	N	N	N	N	N	N	N	N	N	N	N
LIB	N	P	P		P	N	N	N	N	N	N	N	N	N	N	N	N	N
EGY	N	N	N	P		E	E	P	N	N	P	N	N	N	N	N	N	N
JOR	N	N	N	N	E		E	P	N	P	P	N	N	N	N	N	N	N
SYR	N	N	N	N	E	E		N	E	P	N	N	N	N	N	N	N	N
PAL	N	N	N	N	P	P	N		N	N	N	N	N	N	N	N	N	N
LEB	N	N	N	N	N	N	E	N		N	N	N	N	N	N	N	N	N
IRA	N	N	N	N	N	P	P	N	N		P	P	P	N	P	N	N	E
KSA	N	N	N	N	P	P	N	N	N	P		P	P	P	P	P	P	P
KUW	N	N	N	N	N	N	N	N	N	P	P		P	P	N	N	N	P
BAH	N	N	N	N	N	N	N	N	N	P	P	P		P	N	N	N	P
QAR	N	N	N	N	N	N	N	N	N	N	P	P	P		E	N	N	P
UAE	N	N	N	N	N	N	N	N	N	P	P	N	N	E		E	N	P
OMA	N	N	N	N	N	N	N	N	N	N	P	N	N	N	E		P	P
YEM	N	N	N	N	N	N	N	N	N	N	P	N	N	N	N	P		N
IRAN	N	N	N	N	N	N	P	N	N	E	P	P	P	P	P	P	N	

P=Potential pipeline. E=Existing

3.3 Other connections from and into the MENA region

Supplies to and from the MENA region are of course also a possibility. Several connections exists hereunder established connections between North Africa and the Southern European countries. The potential game changer is the evolution of the eastern Mediterranean and the possible supply to Egypt and potentially through the Arab Gas Pipeline (assumed rehabilitated).

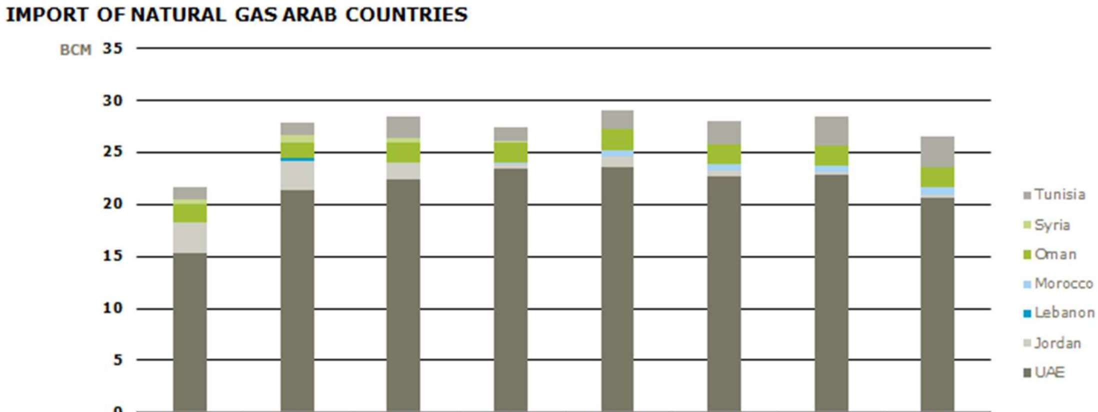
Table 9: Connections to and from MENA countries

	ES	FR	IT	ISR	TU	CYP	PK	AZ	AM	IND	NIG
MOR	E	N	N	N	N	N	N	N	N	N	N
ALG	E	P	P	N	N	N	N	N	N	N	P
TUN	N	P	E	N	N	P	N	N	N	N	N
LIB	N	N	E	N	N	N	N	N	N	N	N
EGY	N	N	P	E	P	P	N	N	N	N	N
JOR	N	N	N	P	N	P	N	N	N	N	N
SYR	N	N	N	N	P	P	N	N	N	N	N
PAL	N	N	N	N	N	P	N	N	N	N	N
LEB	N	N	N	P	N	P	N	N	N	N	N
IRA	N	N	N	N	P	N	N	N	N	N	N
KSA	N	N	N	N	N	N	N	N	N	N	N
KUW	N	N	N	N	N	N	N	N	N	N	N
BAH	N	N	N	N	N	N	N	N	N	N	N
QAR	N	N	N	N	N	N	N	N	N	N	N
UAE	N	N	N	N	N	N	N	N	N	N	N
OMA	N	N	N	N	N	N	N	N	N	P	N
YEM	N	N	N	N	N	N	N	N	N	N	N
IRAN	N	N	N	N	E	N	E	E	E	N	N

3.4 Existing trade - pipelines

Seven of the Arab countries import natural gas through pipelines. All of the imports take place among the Arab countries and are driven by Algeria exporting to Morocco and Tunisia, Qatar exporting to Oman and UAE, and Egypt exporting through the Arab gas pipeline to Syria, Lebanon, and Jordan. See Figure 9.

Figure 9: Import of natural gas through pipelines in the Arab countries



	2008	2009	2010	2011	2012	2013	2014	2015
Tunisia	1,25	1,21	2,05	1,38	1,90	2,20	2,75	2,93
Syria	0,41	0,78	0,52	0,09	0,00	0,00	0,00	0,00
Oman	1,70	1,50	1,84	1,96	1,98	1,97	1,97	1,97
Morocco	0,00	0,00	0,00	0,11	0,67	0,59	0,60	0,65
Lebanon	0,00	0,20	0,10	0,00	0,00	0,00	0,00	0,00
Jordan	2,93	2,89	1,57	0,52	1,00	0,48	0,25	0,24
UAE	15,40	21,39	22,41	23,45	23,59	22,79	22,89	20,73

YEARS

Source: OAPEC

- Countries such as Morocco and Tunisia have increased their imports from Algeria. The volumes which they receive as transit revenue are not counted in this graph.
- Transport in the Arab gas pipeline has been almost halted; only insignificant volumes were imported by Jordan in 2014 compared to 2008 and 2009.
- Both Oman and UAE have significantly increased their offtake from the Dolphin pipeline since 2009.
-

UAE is by far the largest importer and consumer from these countries, and recently it was announced (as described earlier in this chapter) that the Dolphin pipeline would be expanded in order to supply Oman and UAE with just above 30 bcm/y in total. The demand by the UAE is probably correlated with the low price in the pipeline which is between 1-2 USD/MMBTU.

Overall it can be seen that trade between the Arab countries by pipeline increased by 31% from 2008 to 2014 thanks largely to the construction and utilization of the Dolphin pipeline.

3.5 Existing trade - LNG

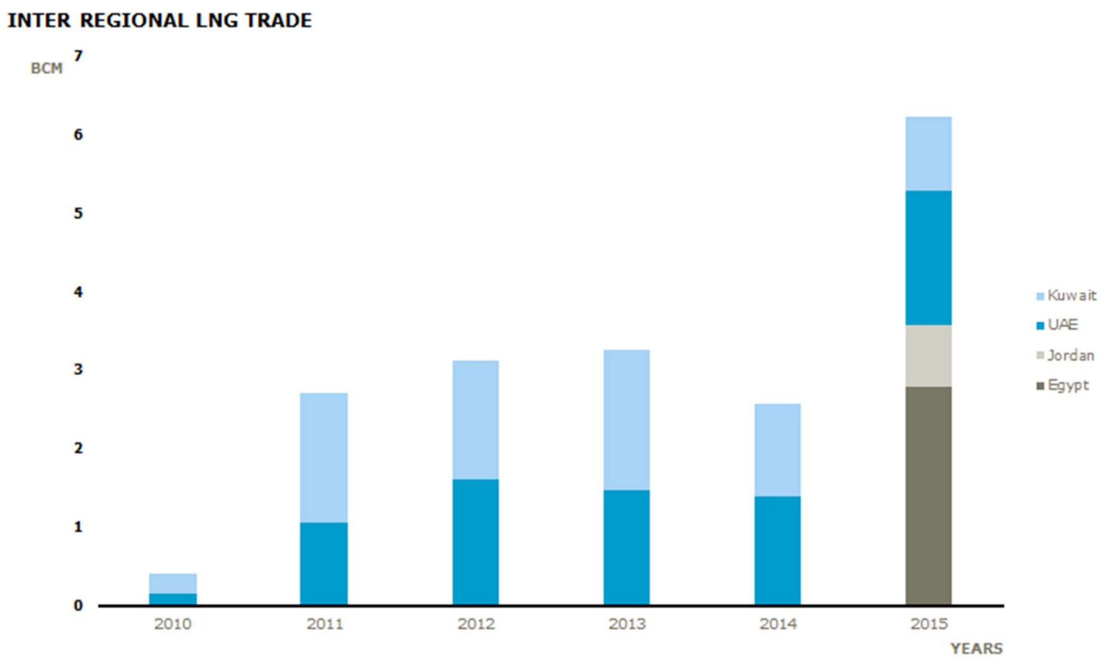
LNG trade amongst the Arab countries is restricted to the exchanges of gas between Qatar and Algeria as the main exporters and LNG importing countries such as Egypt, Jordan, UAE, Kuwait, and in the future probably Bahrain and Morocco. Although historically volumes have been below 3 bcm per year the LNG trade has been shown to be the preferred mode of trade with an increase from 3 to 6 bcm in 2015. While trying to improve upstream conditions and attract foreign investors, several companies are looking for either temporary or permanent solutions to import LNG.

Qatar Gas has signed agreements with Kuwait recently for supply of 0.7 bcm. Since Egypt began importing LNG in 2015 a total of 48 cargoes have been imported, with Qatar delivering 42 of these[2]. Additionally Qatar is known to have agreements with Jordan and UAE (Dubai).

[2] Argus August 2016

The total LNG trade between the MENA countries is illustrated below (see Figure 10), and compared to pipelines, the volumes have been around 10% of the pipeline trade in the period 2010-2014. From 2015 onwards we see a change primarily driven by Egypt and Jordan entering as LNG importers.

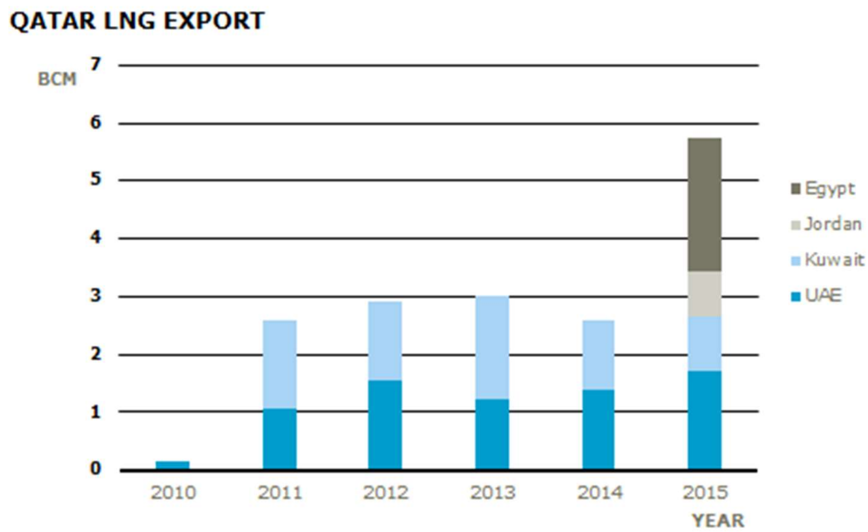
Figure 10: Inter regional LNG trade



Source: OAPEC & IGU

The interregional LNG export from Qatar to the LNG importing countries since 2010 is illustrated below (see Figure 11). No real trends can be observed as the developments are very dependent on discrete events such as new terminals being constructed. LNG is also supplied by a LNG supply company that source the gas and arrange shipping from wherever it is available. Nevertheless in 2015 both Jordan and Egypt entered the club of LNG importers, with both countries relying on the FSRU option to meet demand. Egypt is also using the FSRU from Jordan to source LNG. The supplier countries are primarily Algeria and Qatar. Egypt and UAE have been exporting during the investigated period. UAE still exports volumes to amongst others Asia while Egypt has seized gas exports through the LNG terminals.

Figure 11: Qatar Interregional LNG export

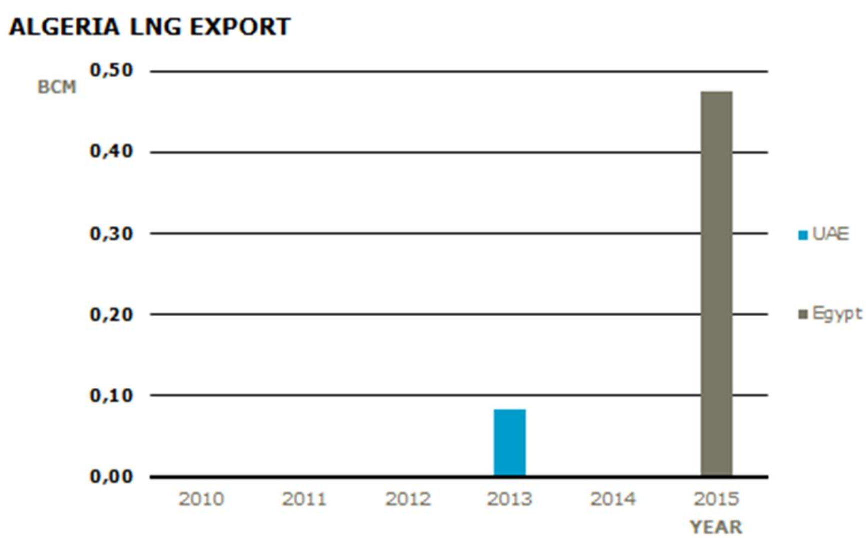


Source: IGU 2010-2015

Given the fact that Qatar has delivered LNG to every single LNG import terminal in the region, it would be a fair to assume that future terminals such as the one in Bahrain and potentially Morocco would rely partly on supplies from Qatar.

Algeria has not been engaging in any significant LNG trade with its neighbouring countries. The only significant trade taking place was in 2015 with the regions efforts to supply Egypt (see Figure 12). It is not known whether Algeria wishes to engage in additional exchanges of gas with distant neighbours in the Gulf in the future.

Figure 12: Algeria interregional LNG export



Source: IGU 2010-2015

3.6 **Existing and future hub development**

It is useful to look at the countries not only on a country by country basis but also on a hub-by-hub basis in particular when discussing the barriers and opportunities for trade we look at:

- Algeria Hub (Algeria, Morocco, Tunisia)

- Libya hub (Libya Tuisia)
- Egypt (Jordan, Syria, Lebanon, Palestine)
- Iraq (Iran, Syria, Jordan)
- Qatar (UAE, Oman, KSA, Bahrain, Kuwait)
- Iran (Oman, Iraq)

Some of these hubs such as Algeria and Qatar are more established than others. In the short to medium term, Egypt could develop into a hub for gas, power, and oil, while Iran has ambitions to increase export capacity. In the long term, both Iraq and Libya could become hubs after satisfying domestic demand.

4. OVERALL SUPPLY DEMAND BALANCE

4.1 General assumptions and approach

A central question in the study is the available volumes for trade between countries. In this context it is also important to understand the possibilities for monetization available to countries with gas. For each country in the demand analysis, we propose evaluating the gas consuming sectors and their prioritization to understand the availability of gas for export and trade between the countries. As gas for power generation is and will be an important sector we model gas consumption in this sector in detail. Consumption in other sectors is projected using Government projections or other 3rd party forecasts, (when we agree with them).

Box 1: Data sources and main assumptions

Data sources and main assumptions

Most data has been sourced from OAPECs databank. The databank contains good information on the gross and net production of gas, reinjection, flaring, import, export, and consumption. In a few circumstances, whenever data were obviously wrong, data have been corrected according to our best knowledge or external sources.

Consumption data have been held up against both BP and IEA. While data are relatively consistent with the overall BP figures, IEA seems to underestimate consistently. We have forecasted the expected consumption in the power sector by usage of the Promed simulator, presented in detail below. Industrial demand growth has been assumed relatively modest due to these industries moving elsewhere or being subject to increased competition from for example the United States.

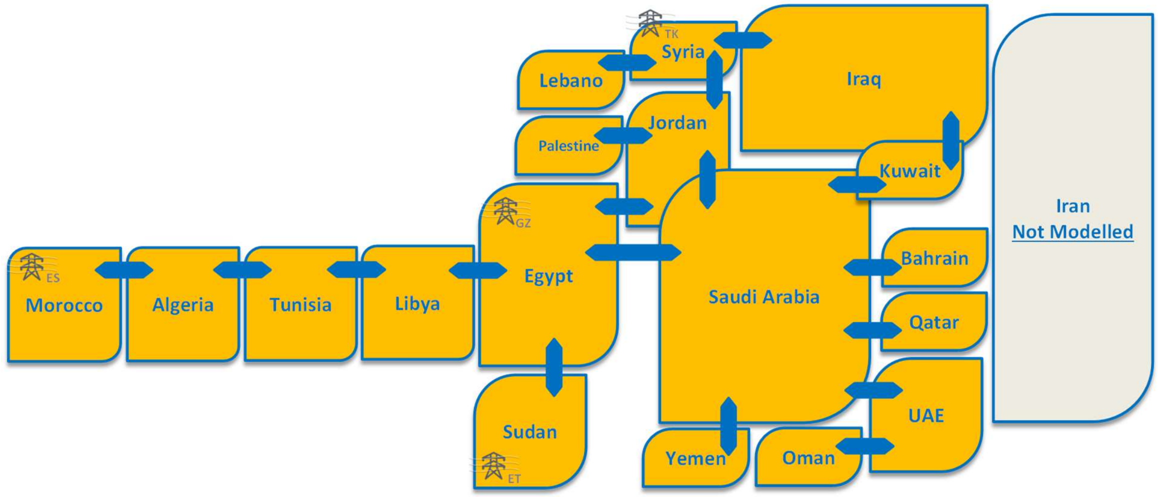
4.2 Estimating gas use in the power generation sector

For understanding the link between prices and the consumption of gas we model the behaviour of the power market. We apply the Power Market Model developed specifically for the region in a previous study by Ramboll and CESI. The main updates and components are:

1. Recent infrastructure development affecting electrical transmission capacity between countries;
2. Recent infrastructure development affecting fuel contract availability in each country of MENA region;
3. Fuel price forecast variations

Regarding item 1: Figure 13 shows the equivalent interconnected market areas modelled in the 2013 AFESD study, one new item here is the Iran which has been added to the existing model.

Figure 13 Applied Market Model



Source: CESI

Regarding item 2: the availability of gas has an impact on fuel contracts constraining power production of thermal units. It may be possible that one or more power plants in one market area are energy-constrained. However, in order to arrive at an unconstrained solution for the region and to obtain clear long-term demand signals we have not applied constraints on the gas supply. If a country demands more than it can currently import, then this signals that new infrastructure is needed.

Regarding item 3: input prices have been determined and locked in at the inception and interim phase and are presented below in Table 10. The initial prices for the PromedGrid model were based on a netback approach. The value of gas, netbacks and cost of production are discussed in more detail in chapter 10.

Table 10: Gas price inputs for the power market simulations

USD/MMBTU	2020	2025	2030
Bahrain	5.0	6.0	7.0
Algeria	4.5	5.5	6.5
Egypt	5.0	6.0	7.0
Iran	3.0	3.0	3.0
Iraq	4.0	4.5	5.0
Jordan	5.0	6.0	7.0
Kuwait	5.0	6.0	7.0
Libya	4.5	5.5	6.5
Morocco	5.0	6.0	7.0
Oman	3.5	4.5	5.0
Qatar	2.5	2.5	2.5
Kingdom Of Saudi Arabia	3.0	3.0	3.0
Syria	5.5	6.5	7.5
Tunisia	5.0	6.0	7.0
United Arab Emirates	5.0	5.0	5.0
Yemen	5.0	6.0	7.0
Lebanon	5.5	6.5	7.5

Palestine	5.5	6.5	7.5
Sudan	5.5	6.5	7.5

Source: Ramboll
Source: Ramboll

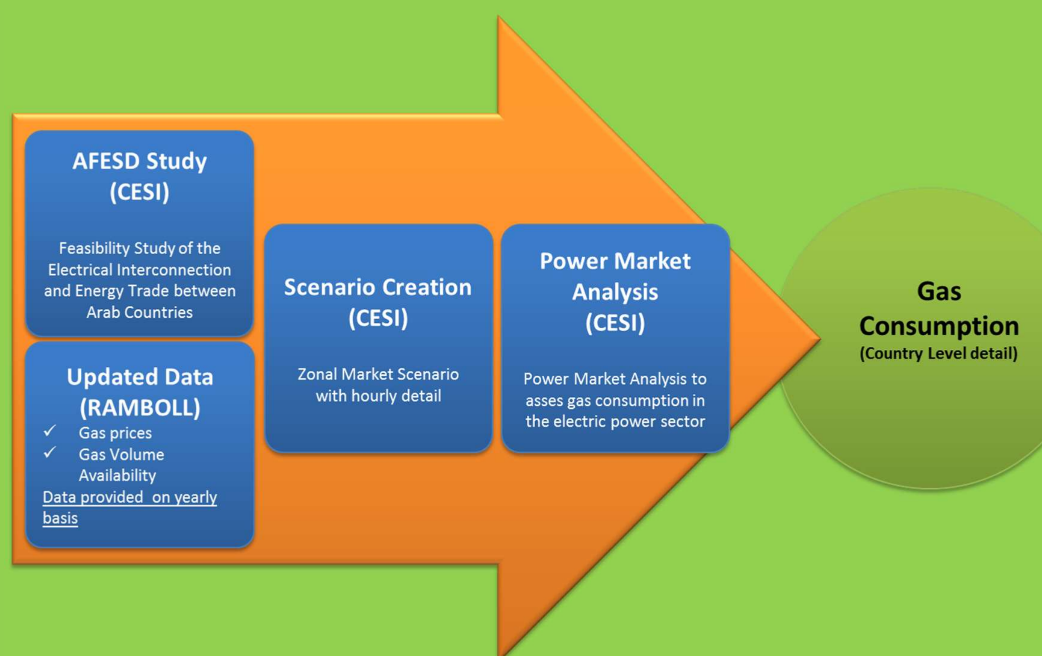
Prices of competing fuels have been set at 70 USD for a tonne of coal and 300 USD for a tonne of HFO reflecting the low crude oil price.

Approach for estimating gas demand in the power generation sector

The technical approach adopted for the study is based on a power market analysis of the interconnected countries, performed by means of PROMEDGRID, the day-ahead market simulator developed by CESI.

The adopted methodology is reliable for estimating gas consumption for the power sector of MENA in future market scenarios as it explicitly models the power generation system and considers each single thermal generation unit and pumped-storage hydro power plant, as well as several equivalent renewable generations.
The software takes into account technical constraints for generation units and transmission constraints among market zones, providing robust quantitative outputs on generation dispatching, market prices and fuel consumption. Only by considering the detailed unit commitment and dispatch of thermal fleets belonging to the countries, is it possible to assess the gas consumption coming from the power sector. Moreover technical constraints on gas availability in each of the countries modelled (due to fuel contract constraints) are taken into account[1].

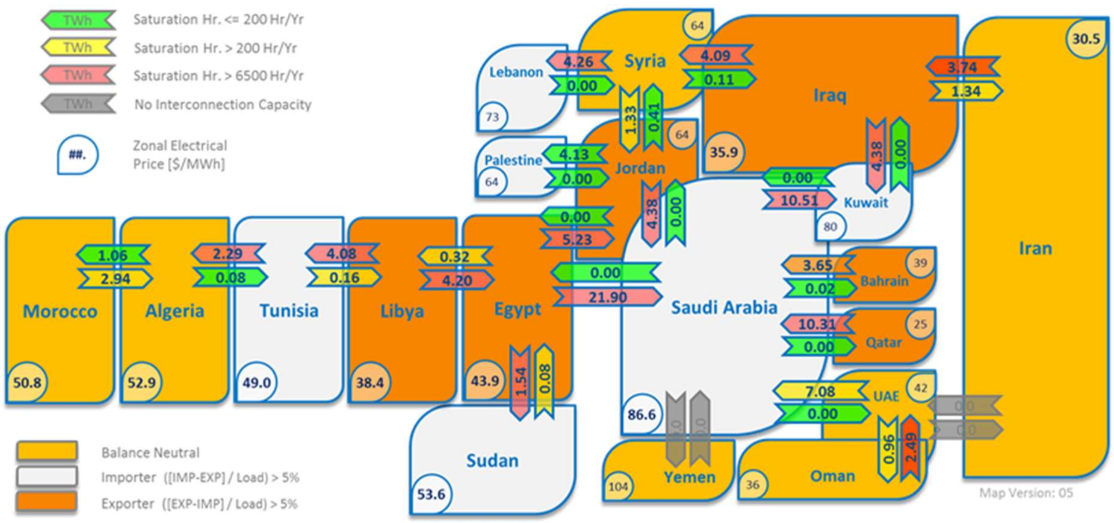
Figure 14 Adopted Methodology for gas demand assessment in the power sector



4.3 Key outputs

A number of the resulting outputs of the power market modelling are illustrated below in Figure 15. The results on a year by year basis are elaborated in the country summaries at the conclusion of this report. (Before perusing the gas demand figures, it may be instructive to visit the electrical flow diagram presented earlier). The utilisation of the electrical interconnections, indicating importing and exporting countries, is shown below. The major country to observe here is Saudi Arabia – it is now importing rather than exporting electricity. This comes back to the assumption of economic prices implying that the world market price of crude oil is adopted for the power sector

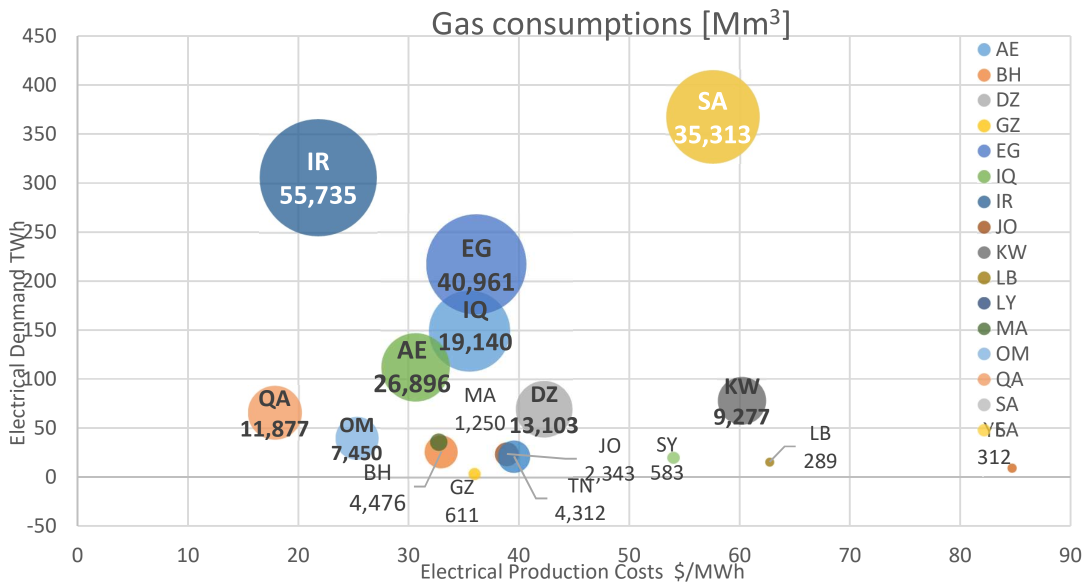
Figure 15: Flow diagram electrical flows



Source: CESI

Error! Not a valid bookmark self-reference. compares the resulting gas demand in the countries to their electrical demand and the resulting cost of production. Electrical production costs are high in countries such as Saudi Arabia and Kuwait as the economic price of crude oil is utilized and they turn to imports instead. In Iran and Qatar it is evident that there is an almost 100% pass through of the low economic gas prices to electrical energy production costs.

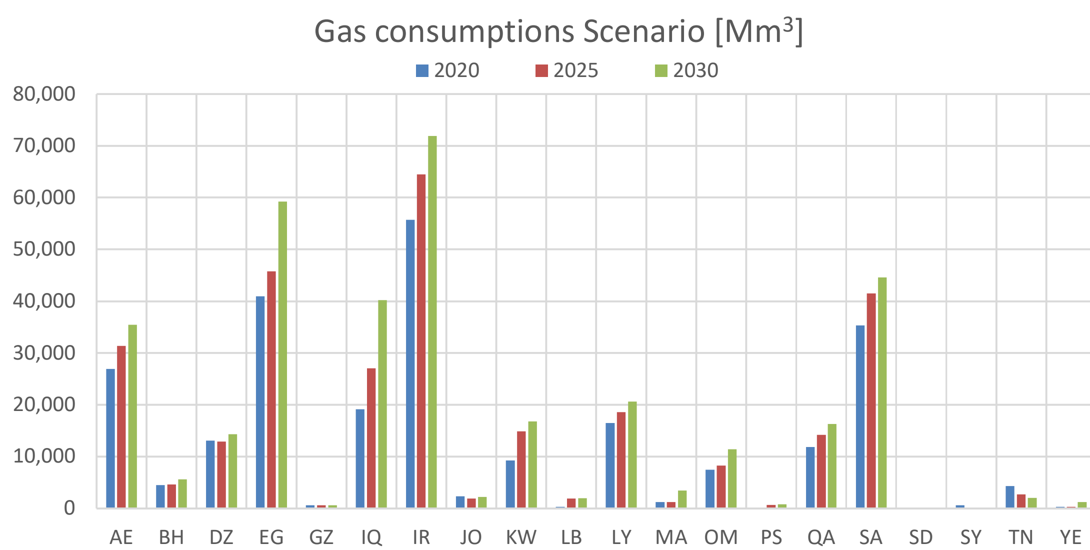
Figure 16: Gas consumption 2020 plotted against electrical demand and electrical production costs



Source: CESI

Over time it is seen that demand in the vast majority of countries will increase demand for gas, with Egypt, Iraq, and Iran in particular showing impressive growth.

Figure 17: Gas demand development in power generation



Source: CESI

4.4 Sensitivity scenarios

To understand the factors affecting demand in the power sector, a number of scenarios have been examined. The scenarios evolve around changes in prices of natural gas and in generation capacity following COP22 in Morocco.

Box 2: Subsidized price scenario

Current domestic prices in the region are in many cases subsidised across sectors and consumer groups (see Chapter 9). Subsidies have distortionary effects on many levels, including as creating artificially high demand, distorting the choices of location of power production and diminishing the incentives for efficiency improvements in power production. For example, if gas prices are subsidised in one country, it chose to produce and export to a neighbouring country despite the fact that efficiency is higher and generation costs are lower in that neighbouring country.

In order to qualify the above hypothesis further,r we applied the PromedGrid model with known developments in each subsidised country. An important limitation is that the model does no provide feedback on overall electricity demand from lower prices as the electricity demand is exogenously given. Thus the effects of subsidies which we can measure directly are the location of power production, demand for gas and flow of electricity between countries - choices which are distorted by artificially low prices

Box 3: Increased share of renewable energy generation in generation mix

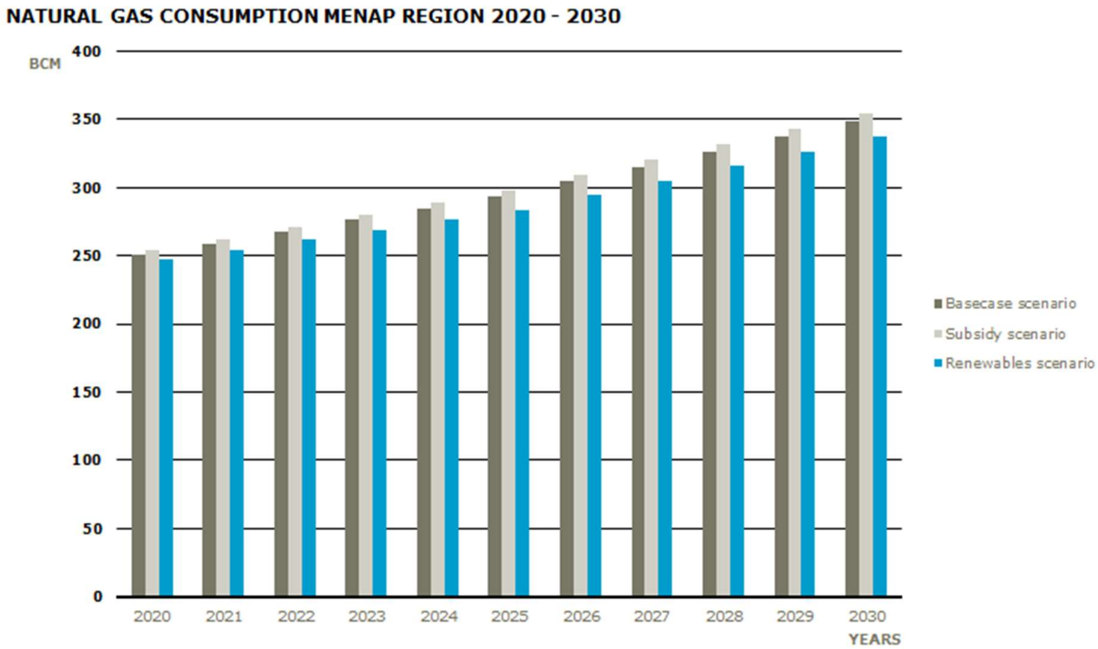
The COP22 meeting provided targets for the introduction of renewable energy in the countries in the region. Some countries have higher ambitions than others and almost all countries would have to invest substantially in order to meet their own goals. However, costs for a number of technologies are falling, efficiency is improving and in general feasibility is more likely than 4 years ago. The hypothesis is that renewables could meet some of the peaks in the daily electricity demand which would otherwise have been met by either oil or natural gas.

To investigate the impacts on the gas sector, specific targets in terms of generation capacity from renewables have been obtained from IRENA and added to the already forecasted generation capacity mix.

4.4.1 Summary of scenario results

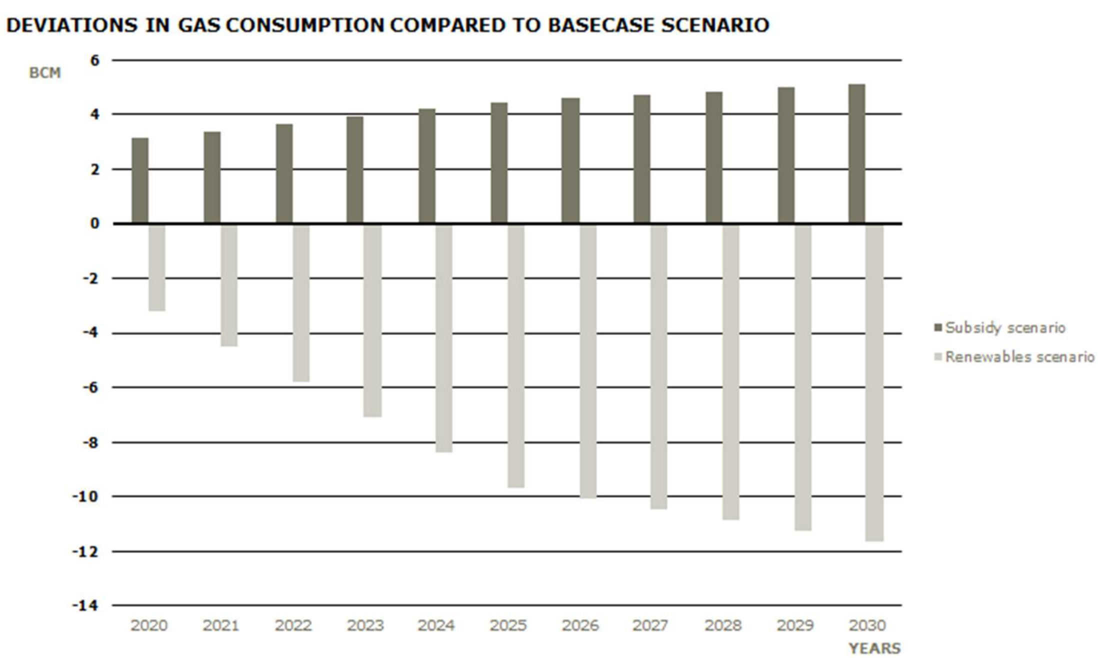
Compared to the base case scenario with economic prices we see that a scenario with subsidized prices implies a higher consumption. This is primarily due to natural gas being used in inefficient power plants.

Figure 18: Natural Gas Consumption MENAP Region



The Renewables scenario results in a decline in gas consumption. However the main effect is not only confined to the gas sector: the use of oil is being reduced in the countries implementing renewable energy. Where oil was previously used to cover peak loads, renewables now kick in and reduce the need for oil/natural gas during peak demand.

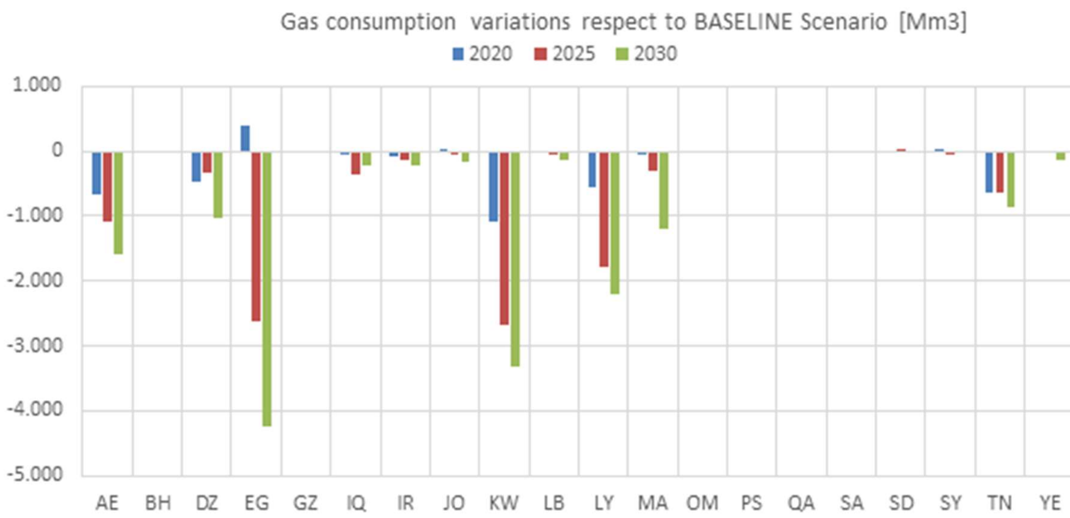
Figure 19: Deviations in gas consumption in the power sector compared to basecase scenario



Source: CESI

The largest effects are seen in Egypt, Kuwait, Morocco, and the UAE as illustrated below in Figure 20.

Figure 20: Gas consumption variations with respect to baseline scenario – country results



Source: CESI

The case must be compelling for OPEC countries in particular where barrels of oil saved in electricity production could go to the world market for sale.

4.5 Summary of country gas balances

Table 11 below contains the summary of the country analysis and shows the development in production, consumption, import and export until 2030. Production was projected using knowledge of existing sanctioned non-associated gas fields and their production forecasts, and this was added to the current production which in most cases has been assumed to decline between 2- 5% per year. This is a conservative approach as undiscovered fields are not taken into account. Consumption is projected using the PromedGrid model of the MENA region for the power sector. The power sector is modelled under the assumption that consumption and trade occurs under unsubsidized (=economic) prices and that there are no restrictions in gas supply.

For the other sectors, industry, residential, government and third-party forecasts have been applied. Whenever none of the above existed, simple projections have been made until 2030. Import is stated as the possibility/capacity to import given todays' and the known future infrastructure figures for 2015 are actual volumes.

It can be seen that production will increase in most countries, a development confirmed by visits made to the region where it was clearly communicated that national production is preferred over any other supply possibility, be it pipeline or LNG from within the region or outside. This choice is motivated by several factors: firstly national production is a way to maintain independence and avoid dependency and influence by other countries. This is not only a MENA phenomenon, even in the most liberalized countries national production is preferred as it is matter of national security. Secondly, trust between countries is generally very low in the region. And thirdly, there is a perception is that LNG provides better security of supply than pipelines. Pipelines make countries dependent on a single source and supplier while LNG opens up for several suppliers.

Looking at the individual countries the following is observed:

Iran holds very large prospects and could, as the worlds' second largest reserve holder of natural gas, become a major player on the global energy scene. However, international trade is limited and most of the gas is being used internally for the time being. This is mainly due to the long term embargo against the country but also due to lack of export infrastructure.

Iran has the possibility of developing the gas production and hereby creating the basis for export and the creation of a gas trading hub. After satisfying the demand of the domestic market, the priority has been to support increased oil production by using gas. Secondary and more medium term goals are to establish gas export possibilities, LNG and pipelines. Given that the South Pars and the Kish fields are being further developed we see this as a clear possibility beyond 2020.

Qatar has had a limit on gas production, partly due to technical reasons, and, partly to avoid becoming over dominating in the global gas market, and partly for political reasons. It has recently (April 2017) been announced that new gas production will be initiated hereby lifting the moratorium. This will allow for increased export of up to 20 bcm/y initially, this export could be in the form of either LNG or via pipelines to neighbouring countries such as Bahrain, Saudi Arabia, UAE, and Oman. Export to markets further afield will require transit via e.g. Saudi Arabia. Lifting the moratorium could imply more volumes than the 20 bcm/y which has been announced – in total 70 bcm of new potential production could been added up to 2030.

Algeria has substantial gas reserves of more than 4500 bcm and has developed a large and integrated gas transmission system, with the giant Hassi R´Mel gas field as the hub. The system, the largest in Africa, is now being extended to the south of the huge country. As the third large reserve holder and trader of natural gas Algeria could over the longer run increase production, this would require better fiscal terms for international companies. Exports out of Algeria will continue thus we have held the 2015 exports out of the region constant over the period, leaving some room for domestic consumption. It is likely that domestic consumption in the future will dictate the availability of gas for export, especially if subsidies are not addressed.

Having reformed parts of its gas pricing scheme, Egypt will be able to increase production significantly in the short term largely driven by the Zohr field and BPs developments in the country. The gas sector has had an uneven development since the creation of LNG and pipeline export a decade ago, shifting to LNG import more recently and possibly again becoming an exporter for a limited amount of years with the Zohr field and a number of other gas fields coming on stream. The developments in the Eastern Mediterranean are important for development in Egypt as additional resources could be brought to shore in Egypt and potentially free up resources for export and trade. However Egypt is in competition with Turkey, Greece and Italy all of whom would like to attract the resources from the Eastern Mediterranean as well.

Iraq has some of the largest gas reserves in the region. At present gas is being flared and pipeline connection between Iran and Iraq has been established but is not yet in use. We expect that some but not all of the current flaring in Iraq can be reduced and converted to marketed gas towards 2030. Today close to 20 bcm is flared. In combination with the fields entering production and the possibility to import gas from Iran, we expect availability to cover consumption. The import option from Iran provides some flexibility as without it there would be no availability of gas for trade (or further domestic consumption). This is shown in the negative self-sufficiency and indicates that Iraq should focus on increasing own its production.

Saudi Arabia, which is projected to consume at least 140 bcm/y in 2030 (Government estimates are higher), is close to a supply deficit at the end of the period. Saudi Arabia is pursuing additional production in shale for example (this has not been included in this analysis). UAE too is experiencing potential deficits in the future, and although gas production will increase with the addition of a number of fields, this is not enough to balance demand.

Table 11: Future gas balances MENAP Region, bcm/y

bcm/y	Production (P)				Consumption (C)				Import (I)				Export (E)			
	‘15	‘20	‘25	‘30	‘15	‘20	‘25	‘30	‘15	‘20	‘25	‘30	‘15	‘20	‘25	‘30
Algeria	88	100	104	94	41	45	50	59	0	0	0	0	44	44	44	44
Bahrain	15	23	21	20	15	19	21	23	0	4	4	4	0	0	0	0
Egypt	44	75	76	70	48	64	72	90	4	0	0	0	0	0	0	0
Iraq	9	21	31	34	9	23	34	51	0	24	24	24	0	0	0	0
Jordan	0	0	0	0	2	3	3	3	2	8	8	8	0	0	0	0
Kuwait	17	17	22	28	22	25	28	31	5	8	15	15	0	0	0	0
Lebanon	0	0	0	0	0	0	2	2	0	2	2	2	0	0	0	0
Libya	13	17	20	25	8	20	23	25	0	0	0	0	5	0	0	0
Morocco	0	0	0	0	1	1	5	5	1	1	5	5	0	0	0	0
Oman	31	36	36	32	22	23	25	30	2	2	2	2	10	10	10	0
Qatar	191	209	259	259	48	48	50	50	0	0	0	0	129	137	137	137
KSA	104	132	132	132	104	107	124	140	0	0	0	0	0	0	0	0
Syria	2	2	10	10	2	2	10	20	0	1	1	1	0	0	0	0
Tunisia	2	4	4	3	5	7	6	5	3	2	2	2	0	0	0	0
UAE	59	52	42	35	71	66	71	75	23	38	34	29	8	8	8	8
Yemen	3	10	15	20	1	5	10	15					2	9	9	9
Iran	182	199	351	351	184	206	228	250	7	7	7	7	9	29	29	29
Total	88	100	104	94	41	45	50	59	0	0	0	0	44	44	44	44

Sources: Historical figures OAPEC, Interviews, Power Market simulations.

Import options are being explored by several countries. However, these are mostly the form of FSRUs which in some cases are temporary until other solutions to the supply problems can be found. FSRUs have recently been installed in Jordan, Egypt, UAE, Kuwait. Bahrain and Kuwait have both opted for a land based terminal while the UAE has indefinitely postponed their land based terminal project in Fuijarah. This underlines the fact that the flexibility FSRUs provides and the limited commitment by the users is attractive to many countries. They are happy to pay a bit more to keep their options open for either increased domestic production or introduction of other energy sources. The only interconnecting pipelines are expected to be between Iran and Iraq. The connection is technically capable of carrying gas but so far pricing disputes are postponing the start up.

To understand which countries could have a surplus of gas we examine the availability of gas after consumption (-), export (-), and import (+), (See Table 12 below). The availability of gas is not only driven by production but also by import possibilities. It is seen to be "high" in Iraq, Kuwait, and Jordan, but this is only because they have the possibilities to trade and import.

However, disregarding the import possibilities and purely looking at self-sufficiency i.e. the ability for a country to cover own consumption by own production, the picture changes; several countries will need to establish permanent or temporary solutions to cover consumption, most notably Kuwait and UAE.

Table 12: Availability of gas and self-sufficiency in gas

bcm/y	Availability of gas (P-C+I-E)				Self-sufficiency (P-C)			
	2015	*2020*	*2025*	*2030*	*2015*	*2020*	*2025*	*2030*
Algeria	3	11	10	-9	47	55	54	35
Bahrain	0	8	5	1	0	4	1	-3
Egypt	0	12	4	-19	-4	12	4	-19
Iraq	0	22	21	6	0	-2	-3	-18
Jordan	0	5	5	5	-2	-3	-3	-3
Kuwait	0	0	9	12	-5	-8	-6	-3
Lebanon	0	2	0	0	0	0	-2	-2
Libya	0	-3	-3	-1	5	-3	-3	-1
Morocco	0	0	0	0	-1	-1	-5	-5
Oman	0	5	3	4	9	13	11	2
Qatar	14	24	72	71	143	161	209	209
KSA	0	26	8	-8	0	26	8	-8
Syria	0	1	1	-9	0	0	0	-10
Tunisia	0	0	0	0	-3	-2	-2	-2
UAE	3	16	-2	-19	-12	-14	-28	-40
Yemen	0	-4	-4	-4	2	5	5	5
Iran	-4	-29	101	79	-2	-7	123	101
Total	17	95	230	111	176	234	362	237

Hoewer, self-sufficiency and LNG imports can be expensive. Thus each of the countries above would have to consider the price of domestic production and import of LNG. We examine this in more detail in the following sections of the report.

Another driver for determining which countries need to trade are reserves compared to their domestic production. The reserve development, given the consumption, is projected below in Table 13. Clearly Bahrain, if the reserves are accurate, will not be able to satisfy the production ambitions for very long. Tunisia is running out of reserves as well, and could face increasing costs of production as the last 10 bcm could be more expensive to produce than the first. Egypt and Oman are both in the middle field with less than 50 years of production left, if the reserves estimates are correct.

Table 13: Reserve development and reserves to consumption ratio

bcm	Reserves (R-cumulative C)				R/C_2015
	2015	*2020*	*2025*	*2030*	2015
Algeria	4.505	4.095	3.704	3.333	111
Bahrain	92	4			6
Egypt	2.186	1.867	1.475	1.111	45
Iraq	2.980	2.913	2.766	2.588	343
Jordan	6				3
Kuwait	1.784	1.699	1.601	1.476	80
Lebanon	420				
Libya	1.532	1.461	1.368	1.255	200
Morocco	1				2
Oman	706	540	352	183	32
Qatar	24.400	23.435	22.340	21.045	510
KSA	8.316	7.674	7.014	6.353	80
Syria	285				154
Tunisia	65	47	28	11	12
UAE	6.091	5.810	5.581	5.393	86
Yemen	479	458	393	303	669
Iran	33.628	32.445	30.848	29.938	182
Total	4.505	4.095	3.704	3.333	111

Source: OAPEC historical & Ramboll projections

5. SECURITY OF SUPPLY

5.1 Current approach and status

The importance of security of gas supply cannot be understated. It is a key element in providing gas trade, in particular because gas is most often used for power production and consumed directly in the residential sector. The costs of gas supply disruptions can quickly amount to many million or even billion USD and in the worst case, can bring down governments.

Additionally, the importance with respect to trade can also not be understated either. The certainty of delivery and the assurance that demand can be met under even the most severe circumstances is a precondition for trade and would lower transaction costs between parties as the risk of default is reduced.

The current approach between the MENA countries is very much unilateral approach where the first priority in each country is to maximise production if they can – even if it is expensive. Bahrain for example, seeks to develop domestic production and import of LNG despite being within short distance from the worlds' largest gas field, the North field in Qatar. This approach is to some degree understandable as with the Arab Gas Pipeline has been put out of action a number of times during the past year and the attractiveness of onshore pipeline infrastructure between countries is limited. On the other hand, the unilateral approach leads to inefficient allocation of resources with a welfare loss for the populations of the MENA region. A second priority is to import LNG which in the region is seen as a security of supply improvement. The countries with some hope for increasing domestic production or obtaining gas from elsewhere (Egypt, Jordan, UAE) chose the FSRU solution which offers flexibility and elimination of the risk of stranded assets. The third priority is pipeline interconnections. Although some countries are interconnected, the fact remains that most countries are either reliant on their own production or LNG imports.

5.2 N-1 EU infrastructure standard applied to the MENAP region

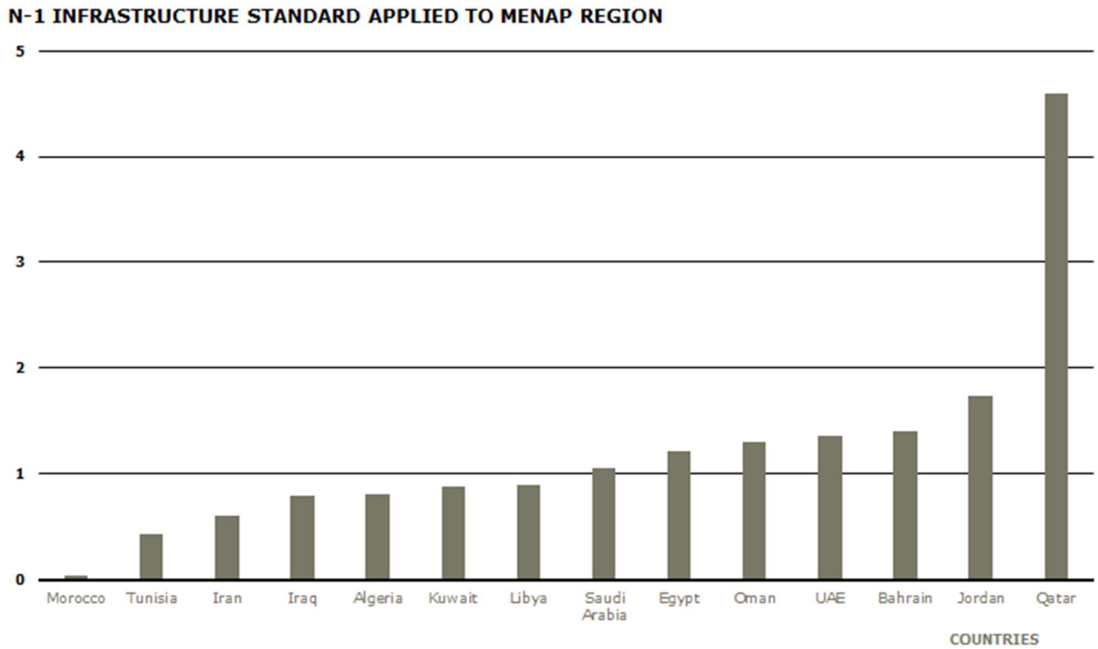
Few general measures exist for evaluating security of supply across countries. To investigate this we apply the European infrastructure standard as laid out in regulation 994/2010, also known as the N-1 infrastructure standard. Specifically it shows whether a country is capable of covering peak demand if the single largest piece of infrastructure disappears.

$$N-1[\%] = \frac{EP_m + P_m + S_m + LNG_m - I_m}{D_{max}} \times 100, \; N-1 \geq 100\,\%$$

EP = technical capacity of entry points other than production and LNG
P = production capacity
S = storage
LNG = LNG
I = single largest infrastructure
D = exceptionally high gas demand 1 in 20 years event.

Few countries have significant other entry points to their system and the majority of countries have all of their flexibility in the production capacity. Only Iran has some storage capacity – while others might have indirectly through flexible use of gas fields. Exceptionally high gas demand is determined as 1.5 times the average gas daily demand unless other figures are known.

Figure 21: N-1 calculation 2020

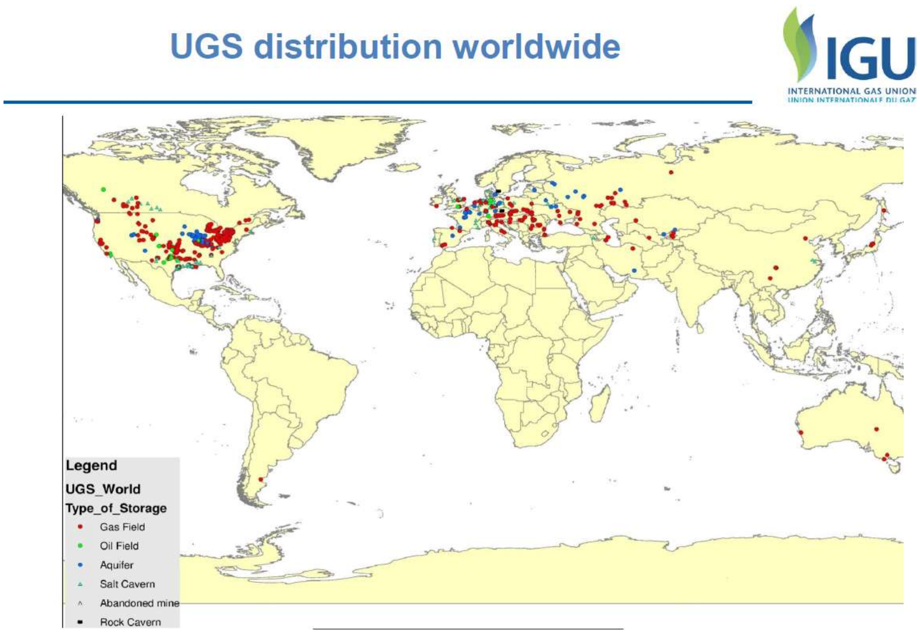


Source: Demand and supply projections. Peak daily demand and production assumed factor 1.5 higher than average consistently across countries

The application of the N-1 rule shows that only the countries with either very high production or alternative supply sources in form of pipelines or LNG pass the N-1 criteria. Some countries could be in risk of being over reliant on one single supply source internally as well. An example of this is Algeria where the Hassi R'Mel plays an important role in the supply of gas for domestic consumption and export. It can also be seen that only Qatar exceeds 2, Jordan is just under 2 and the rest of the countries passing the criteria, Saudi Arabia, Egypt, Oman, UAE, Bahrain, closer to 1 than 2.

It is clear that all countries could improve their security of supply but the question is how? Egypt, UAE, Bahrain, and Jordan have opted for the LNG solution to meet peak demand and to add alternative supply sources; however, this solution is expensive. Peak demand could be covered in other ways and more efficiently by the use of underground gas storage. The purpose of underground gas storage is to ensure high utilisation of infrastructure as well as high security of gas supply and its development can support regional trade by bringing down the unit cost of transportation. In Europe, almost each and every country has storage capacity available. However, none of the Arab countries in this study have developed underground gas storage. Iran is the only Middle East country, which has its own gas storage facilities according to the IGU data base. It developed the storage capacity from 2012 to 2015 from a low base. Iran today has the tenth largest global storage volumes compared to the 3rd largest production.

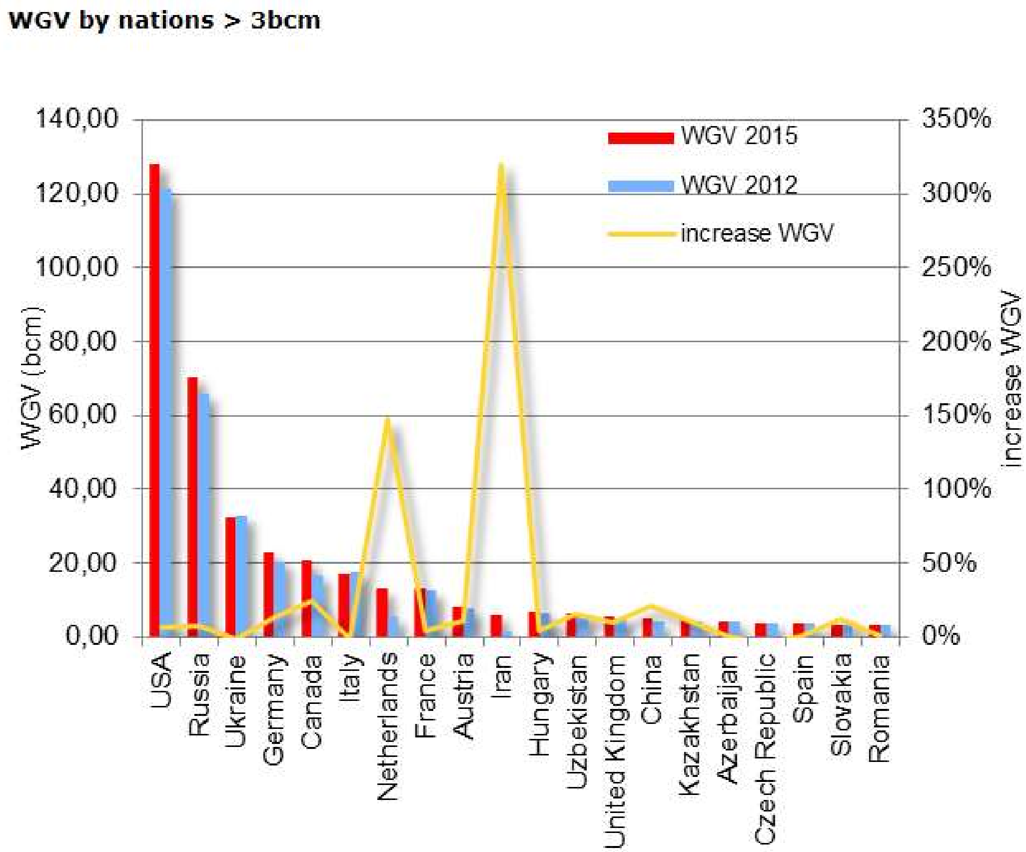
Figure 22: Underground Gas Storage facilities in the World



Source: IGU

Figure 22 (above) clearly shows the absence of storage facilities in the MENA region. Figure 23 (below) shows that countries importing gas from the MENA region such as Italy and France have large storage facilities. However the largest storage facilities exist in gas producing countries like USA, Russia, Canada, The Netherlands, and in transit countries like Ukraine, Germany and Austria as well as gas consuming countries like France and Italy.

Figure 23: Working gas by nations > 3 bcm

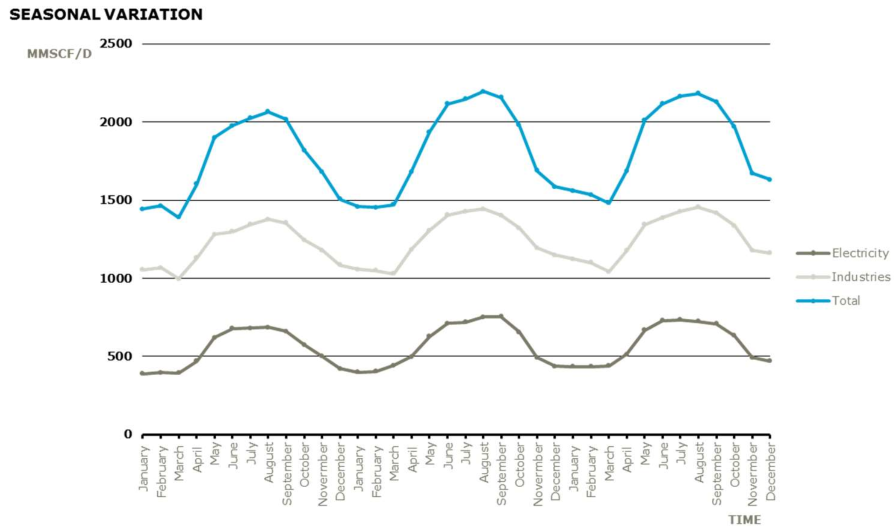


Source: IGU

The main driver for underground gas storage has been balancing gas demand between summer and winter in countries where gas was mostly used for heating. Further underground gas storage has been used for the security of gas supply in consuming countries as well as gas exporting countries such as Norway, Russia and Azerbaijan to ensure that technical problems with production facilities did not stop export and supply.

The Arab countries and the Middle East in general differ with respect to seasonal development in gas consumption. However little data is available in the public domain and this makes it difficult to assess the real need for seasonality.

Figure 24: Seasonal consumption of gas in a Gulf country



Source: AFESD study 2013

The example above shows the typical seasonal development in gas demands in the electricity sector and the industrial sector respectively. In both sectors, highest consumption occurs during summer, linked to the demand forcooling.. In other countries where gas is used for heating there is also a winter peak.

A number of gas producing countries like UAE, Egypt, Kuwait and Bahrain have either established or are establishing LNG import facilities to be able to meet peak demand. Only a few countries such as Morocco are presently exploring the possibility for underground gas storage.

One of the reasons for choosing LNG import facilities instead of UGS may be that international gas prices are typically higher during winter than during summer. However, this difference has been significantly reduced in Europe in recent years.

Additionally underground gas storages have many other virtues:

- They provide security of supply close to the demand centres
- They provide physical flexibility – compared to hubs for example
- They solve bottlenecks internally in the system
- They can form an important part in the transition towards renewable energy

For the region, security of supply close to demand centres could be relevant in countries such as Algeria where many new fields are located in the south a long way from demand on the coast. In many ways this situation resembles that of the Netherlands where the Groningen field was relied upon for flexibility for many years – similarly to Hassi R'Mel – and gas storage was introduced relatively late compared to many neighbouring countries. Gas storage may also be relevant in Saudi Arabia as many of the future gas fired power plants are located in the western part of the country while much of the production is in the east. From a hub perspective it would make sense to have gas storage in Egypt to support its aspirations to become a trading hub for the region, and the same could be the case for UAE.

Some countries could and often achieve situations with simultaneous import and export. Iran is already in such situation. Algeria is planning the Trans-Saharan Gas Pipeline and Egypt is switching between exporting and importing. These countries can most obviously develop into trading hubs where it will be an advantage to be connected directly to the EU gas market via pipelines and have access to LNG export and import facilities. This makes Egypt and Algeria the most obvious candidates; however Egypt still lacks a pipeline to Europe and Algeria lacks an import pipeline from either Libya and Egypt or Nigeria.

6. BARRIERS AND OPPORTUNITIES

6.1 Summary of barriers and opportunities

Incentives for regional gas integration and trade have historically been a combination of geography, economic incentives and the creation of political alliances. The existing pipeline connections between Algeria and Morocco and Algeria and Tunisia were established to connect gas reserves in Algeria with Europe and were therefore supply driven. The Arab pipeline was a combination of the political will for cooperation, demand driven from Jordan, Syria and Lebanon, and ultimately connection to Europe. The Dolphin pipeline was a combination of economic rationale to bring cheap gas from Qatar to UAE and Oman, establishing a connection from Qatar to LNG export plants outside the Hormuz strait, and creating political cooperation between these countries.

Resource policies

Resource policies of countries may set restrictions on the production of gas for the market. Some examples from Europe are:

- The Netherlands has had a 25 year rolling resource policy to stretch gas reserves and mix gas export with gas import to become a gas hub. The policy includes an offtake obligation for small fields. This encourages the development of smaller offshore gas fields rather than production from the low cost onshore Groningen field. Recently the country introduced limits on production to avoid earth quakes and subsidence. Originally the reason for production restriction was to avoid too high dependence on gas export (Dutch disease).
- Norway has used gas for enhanced oil production rather than for direct gas export. This brings the gas to market at a later stage when oil has been produced. Norway also delayed oil field developments until a solution for bringing the associated gas to the market had been found, which enhances production and reduces flaring.
- France has banned the use of fracking to produce gas

In the Arabic countries the best known example on resource policy is the Qatar moratorium on increasing gas production from the North Field which has now been lifted. Other dilemmas concerning gas production and resource policy are:

The choice between oil and gas production if financial and human resources are limited, as in Iraq: Should the focus be on increasing oil production or gas production? As oil production in oil rich countries is generally more commercial and technically attractive than gas production, there will generally be a tendency to give priority to oil production. Such considerations have cancelled or delayed many gas trade projects during the past decades. The MENA countries where the focus on oil is most likely to be a barrier to gas trade projects are Iraq, Iran, Libya, and Kuwait.

The use of gas for enhanced oil recovery: as in Algeria and Libya, where a substantial part of produced gas is used for maintaining pressure in oil fields. The same is the case in Iran and the UAE. The balance between oil and gas focus will depend on price, very low indigenous gas prices will tend to favour re-injection of gas rather than bringing gas to the market.

Shale gas production: large potential resources have been identified in Algeria; its production requires water but as water is a precious resource in the region, this could become a barrier to development.

OPEC policy and quotas on oil production will in many Arabic countries impact the balance between oil and gas production. With the change in OPEC policy in 2014, the focus was on oil production and gaining market share until new production limits were introduced in late 2016. As the limitation on oil production is on production rather than export, there will be incentives to reduce indigenous oil consumption by replacing with e.g. gas and by increasing prices, (gas production and LPG do not fall under the OPEC quota either). There will therefore be new incentives to increase gas production in 2017. Saudi Arabia is the best example of this as they are pursuing a significant expansion of their gas production capacity for supply to the power sector, substituting oil.

Gas Flaring

Flaring is still taking place in many countries and can be an additional source of gas for increased trade if collected and marketed. In 2015, around 50 bcm of associated gas was flared in the MENA region. The estimates for top flaring countries were: Iraq: 16.2 bcm, Iran 12.1 bcm, Algeria 9.1 bcm, Egypt 2.8 bcm, Libya 2.6 bcm, Qatar 1.1 bcm, UAE 1.0 bcm, and Kuwait 0.9 bcm and the trend is increasing in Algeria, Egypt and Iraq.

In 2014, the World Bank launched the Zero Flaring Globally by 2030 initiative, committing oil companies that endorse it to develop new oil fields they operate according to plans that incorporate sustainable utilization or conservation of the field's associated gas without routine flaring. Oil companies with routine flaring at existing oil fields they operate will seek to implement economically viable solutions to eliminate this legacy flaring as soon as possible, and no later than 2030. Governments that endorse the initiative will provide a legal, regulatory, investment, and operating environment that is conducive to upstream investments and to the development of viable markets for utilization of the gas and the infrastructure necessary to deliver the gas to these markets. Development institutions that endorse the initiative will facilitate cooperation and implementation. In the MENA region only three governments (Bahrain, Iraq and Oman) and two companies (KOC Kuwait, PDO Oman) have endorsed the initiative to date[3].

Some generic lessons can be drawn from successes in reducing gas flaring reduction and associated gas utilization achieved by a number of oil producing countries, such as Algeria, Canada, Norway, the United Kingdom, and the United States. It should be noted that a combination of the following measures is essential to achieve significant reduction in flaring and venting[4]:

1) Oil & gas legislation, and oil & gas concessions/licenses, should be clear, comprehensive and unambiguous on the treatment of associated gas.

2) Fiscal terms should encourage associated gas utilization investments. Special fiscal treatment of associated gas investments may be needed to overcome the high up-front capital cost and (relatively) poor economics of associated gas utilization projects.

3) The gas market should encourage and enable associated gas utilization. This could be achieved by giving the oil & gas companies the right to monetize gas, generally including gas export. Providing open and non-discriminatory access to infrastructure, including gas processing and transmission facilities, and to electricity grids (to sell electricity produced on-site from associated gas); and finally the introduction of market based pricing.

4) Flare and venting regulation should be clear, with effective monitoring and enforcement: The right market conditions and investment incentive schemes should be complemented by flare and vent regulation in order to challenge operators to consider every gas utilization option.

[3] http://www.worldbank.org/en/programs/gasflaringreduction
[4] GGFR: Guidance on Upstream Flaring and Venting. Policy and Regulation, 2009.

5) Reduction in legacy flaring requires a comprehensive and methodical approach: A generally accepted approach to address legacy flares and vents is to (i) create an environment enabling gas utilization investments (ii) establish a realistic flare/vent-out deadline (iii) coordinate operators' investment programs, and (iv) closely monitor them to ensure that they are implemented on time. Developing these flare reduction programs should be a cooperative approach in consultation with key stakeholders, particularly the operators. Although stakeholder consultations will take time and effort, they typically add value by:
   - Establishing a challenging, but realistic flare-out deadline;
   - Identifying key issues and risks in implementation of operators' associated gas utilization programs, which in turn allow these to be addressed in timely fashion;
   - Developing a fiscal framework consistent with the country's flare and vent reduction policy;
   - Transforming the potential of the policy into results on the ground through greater trust, ownership, and commitment by stakeholders.

6) New oil developments should include provision for associated gas utilization:
   - In new oil developments, associated gas utilization should be an integral part of the field development planning process.
   - Addressing flaring and venting retroactively is more costly and often more technically challenging.

7) An integrated plan should be developed for both associated and non-associated gas: Flaring and venting reduction and non-associated gas development should be integrated into a country gas master plan and/or energy sector strategy

Political issues inside and between countries and impact of gas and energy trade

War and civil unrest is a major barrier to trade, in particular for natural gas via pipelines which requires new investments and dependence on both the seller and the buyer side. The MENA region has been exposed to numerous conflicts which have held back gas trade and establishment of new pipeline connections.

In other parts of the world there are examples of continuous gas trade via pipelines despite conflicts. For example, gas continued to flow in the South Caucasus gas pipeline in Georgia during the Russian intervention in 2008. Gas transmission to Bosnia-Herzegovina continued during the war and the siege of Sarajevo. And even during the civil unrest in Ukraine and the Crimea crises the transit of gas continued, although Ukraine greatly reduced its own gas imports from Russia.

At present there is conflict in Syria, Iraq, Libya and Yemen; and there have been terror attacks on gas infrastructure in Algeria in 2013. These events are holding back new investments as well as existing production and export. As an example the LNG export from Yemen has been put on hold. During the unrest in Libya the gas export to Italy has occasionally been on hold, but surprisingly the Libyan flows in 2015 were of similar size as the Algerian flow to Italy.

The risk of wars, civil unrest and terror attacks show the need for several alternative routes for gas import and introduction of security of supply via N-1 criteria, as discussed in chapter 10 and use of underground gas storage, use of offshore pipelines and LNG as back-up. Experience has shown that it is difficult to predict new conflicts.

The main ongoing violent conflicts in the region are:

Libya – lack of stability
The unstable situation in Libya has resulted in a situation without clear governance of the country. There has been a continuous low level conflict with sporadic outside intervention. Consequently it has not been possible to promote new projects and oil production has fallen. Gas export has continued although gas production from the Sirte basin has been impacted. Power supply is unstable.

Syria – the war has escalated
The war in Syria has escalated and the risk for widening of the war to neighbouring countries like Lebanon, Iraq and Jordan also impacted the potential projects in these countries.

Iraq – IS
In Iraq part of the country was taken over by IS and focus was on oil production. Gas import from Iran could be started but is so far on hold until final agreement is reached. Development of gas projects in the Kurdish region have also only been progressing slowly due to the security situation.

Yemen – war and involvement of Saudi Arabia and other Arab countries
Yemen was exposed to a change in government in 2014, when Houthis took over the capital Sana'a. This was followed by intervention by a Saudia Arabia lead coalition, also involving Egypt, Morocco, Jordan, Sudan, the United Arab Emirates, Kuwait, Qatar and Bahrain. As a consequence the LNG export was halted and oil production reduced to a minimum. No new gas projects were promoted.

Egypt - coup d'état – and election of new president in 2014
Egypt was exposed to a change of government several times from 2011 to 2014 as part of the Arab spring. After the election of Sisi as president in 2014, there has been more stability, but there is still a lot of uncertainty. For the gas sector the situation from 2011 resulted in halt of LNG export and start of FRSU LNG import. Sabotage against the Arab pipeline increased and start small scale gas import from Jorden FSRU commenced. At the same time, exploration and development activities were accelerated with fast track development as the supply of energy to the population was seen as the highest priority.

Long lasting conflicts impacting gas planning
Apart from the eruption of conflicts since 2014, there are a number of long lasting conflicts which impacts gas planning:

- Israel- Palestine
- Morocco- Algeria in West Sahara
- Iran situation and embargo

Despite these conflicts it has been possible to establish gas trade between Algeria and Morocco, Israel, Egypt and Jordan and most recently Iran and Iraq.

6.2 Embargos, lack of cooperation and other political restrictions on gas export

Historically a number of countries have been exposed to embargos, external political restrictions on gas export, restrictions on the movement of key persons or restrictions on financial operations. In the MENA region this has been the case for Iran, Iraq, Sudan and Libya and the the risk of new occurrences become a barrier for investment.

At present most of the historical embargos have been halted, but there are still restrictions from US on e.g. Iran, which may hold back new projects; the South Pars development for example could be delayed/impacted as it depends on the renewal of US sanction waivers.

There is also lack of cooperation between the Arab countries and in some cases hostilities related to issues beyond the gas theatre. Internally there are also local regional differences which may hinder development of infrastructure and trade.

The lack of cooperation between Morocco and Algeria is the most obvious case, where gas production from Algeria can easily be brought to the market in Morocco which is in need of gas import. The conflict in West Sahara however limits overall cooperation. Furthermore, the need for gas transit from Algeria to Spain via the Maghreb gas pipeline resulted in payment of transit fees, which is not encouraging further transit when the transport deal expires.

A Libya-Tunisia gas pipeline has been planned for decades but so far has not materialized. This was probably due to the interest of ENI who favoured an offshore pipeline solution to Italy, as well as historical high transit tariffs via Tunisia and general lack of cooperation, embargos and in recent years, conflict and lack of security.

Qatar-Bahrain and Qatar-Kuwait are obvious pipeline connections which have so far not materialized due to lack of cooperation.

The possible cooperation on gas development between Iran and Iraq, Syria, Kuwait, Bahrain and Oman can significantly change the development. It can be expected that Iran will export large volumes of gas at low cost in coming years. This could take place via Iraq and Syria to Europe or via Oman to India by pipeline or as LNG.

In conclusion embargos, lack of cooperation and political restrictions are some of the most important elements that go towards in restricting regional gas trade.

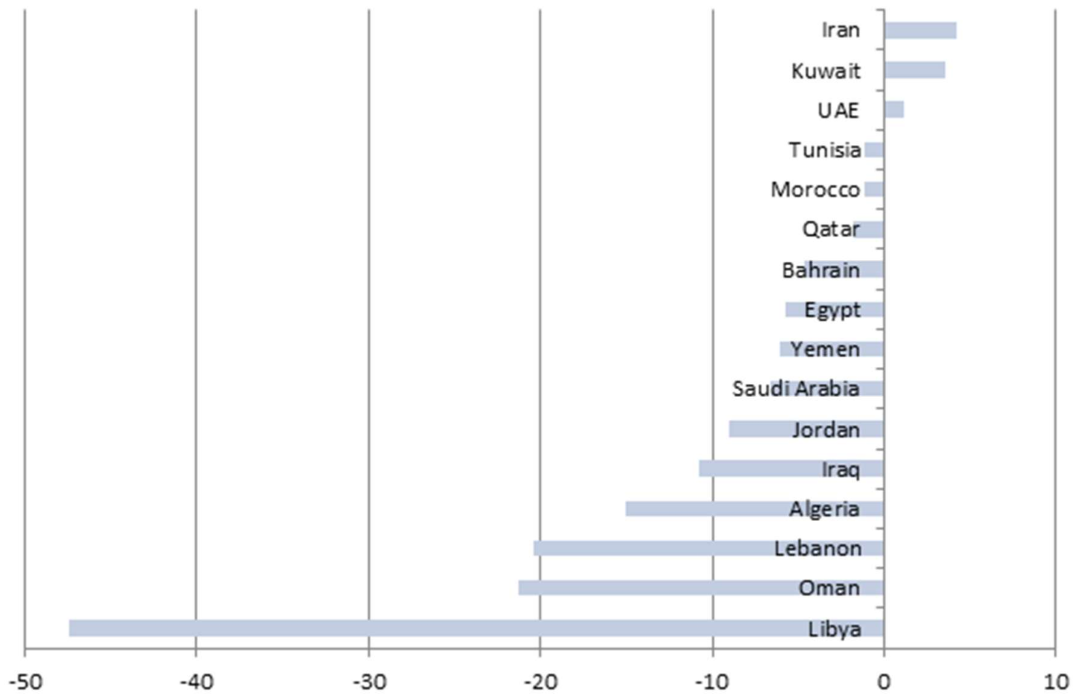
6.3 **Macroeconomic priorities**

Balance of payment, inflation, financial deficit, exchange rate and growth are some of macroeconomic priorities which may impact the decisions about gas and other energy trade and thus decisions about establishment of new projects.

With the decline in oil prices in 2014 the oil export and import situation changed dramatically for countries in the region. Many oil exporting countries that had a comfortable surplus on trade when oil and gas prices were high now had to draw on financial reserves.

The decline in oil prices in 2014 has resulted in large imbalances in both the fiscal and current accounts.

Figure 25: Current account balance as % of GDP



Source: IMF

Increased gas production, export or the substitution of oil will be an incentive to increase gas production in countries with large reserves such as Libya, Oman, Algeria, Iraq, Saudi Arabia and Egypt. The current account surplus in Iran is mostly due to sanctions, preventing import of goods and services. Most countries also have large government fiscal deficits, which may be mitigated by reducing subsidies and switching from oil to gas.

The consequences of the macroeconomic imbalances differ from country to country and impact the gas trade in different ways. Some examples are:

8) Saudi Arabia can increase oil export by shifting to gas and hereby reduce the current account and government fiscal deficit
9) Algeria can increase exports to Europe, Morocco and Tunisia in order to improve balances, which will require reduced consumption internally. This could be achieved by exchange rate and subsidy changes
10) Egypt has already decided to let the currency float, which will lead to lower gas production cost measured in international currency and reduced gas consumption as prices will increase
11) Qatar can increase gas export to neighbouring countries to improve the balances

The October 2016 IMF report on the situation in the MENA Region shows that the fall in oil prices has resulted in a rapid change in the macroeconomic situation in many of the oil producing countries. For this study, the following findings are important:

12) Algeria has gone from fiscal and current account surplus before the oil price fall to double digit deficits. These deficits have so far been covered by previous savings in sovereign funds, but this is not sustainable in the long term. Therefore, increased gas export on the account of indigenous consumption could be a solution. Also, opening of access to foreign investments can contribute to balancing the situation. It all points towards efforts to increase production and export, the same solution as other gas exporters outside the

region such as Russia and Norway. It is also likely that the exchange rate will be adjusted to take into account the new situation.

13) Qatar is still in reasonable shape with respect to financial and current accounts, but the overall financial balance is turning negative. Despite a reasonable current account, the situation calls for the reduction of subsidies and indigenous consumption of oil and gas. The situation is less urgent than in Algeria, but uncertainty about gas prices in the long term may change this. Part of the solution could be reduced fuel subsidies and the employment of the local population in the private sector.

14) Saudi Arabia is in particular impacted on the government fiscal balance and the balance of payment is also impacted. Saudi Arabia's oil policy is important and depending whether it focuses on winning market share against pushing up prices, there may be a demand for increased gas consumption to replace oil in the power sector.

15) Libya is impacted by ongoing conflict, resulting in large deficits on government fiscal balance and current accounts. The focus of Libya will be to restore oil production in the short term; as there is a lack of gas for power production, there may be a need for limiting export and this will impact the current accounts. Additionally, the current infrastructure doesn't allow for the transport of large amounts of gas to Tripoli or other population centres

16) Iran is the country among the large gas producers in the region that has the most robust balances as it has moved from an embargo situation to exporting again. There will therefore be room for a more long-term view than in some of the other countries.

17) Iraq has negative balances, partly due to the ongoing war, but also due to a large population. However, oil production is increasing steadily and balances improving depending on the oil prices. This may in the short-term provide and opening for gas import from Iran and for focusing more on gas production than oil production. If there are new OPEC quotas for oil production, one solution will be to develop gas fields, including NGL production, that are not impacted by such quotas.

Among the oil importing countries there should be a positive impact of the fall in oil prices. However, the second order impact from oil producing countries may erode this. This is in particular due to less remittance from workers from e.g. Egypt working in the Gulf States.

18) Morocco has in particular benefited from the lower oil prices, with improvements in all parameters, and in particular a reduced balance of payment issue. This opens up for increased import of gas. Morocco has had almost no direct income from oil and gas production and will hence harvest the full benefit of lower oil and gas prices.

19) Egypt is in a different situation with a higher current account deficit, very high inflation and high government fiscal deficit. This is because as an oil and gas producing country with companies and individuals working in the Gulf States, Egypt resembles is more like the oil exporting countries. In addition internal developments put pressure on public spending. The result has so far been a devaluation of the currency by around 50 percent and there is a risk that price subsidies will continue in order to limit inflation.

20) Tunisia still has a high current account deficit. Therefore there will still be constraints on increasing import of gas.

The macroeconomic situation due to falling oil prices may favour more gas trade between the Arabic countries, in particular in the following cases:

21) Algeria to Morocco, which could benefit both countries
22) Qatar to oil exporting countries, Saudi-Arabia, Bahrain, UAE, Oman and Kuwait to be able to replace oil presently used for power generation for export.

6.4 High transit tariffs for gas export – Morocco, Tunisia as examples

When gas transit from Algeria to Europe via Morocco and Tunisia was established in the 1980's and 1990's, it was not technically possible to cross the Mediterranean Sea directly by pipeline. Consequently the alternative was expensive LNG export which was used until establishment of the pipelines. This resulted in a very favourable negotiation position for the transit countries due to the unexpected surge in oil prices from 2005 to 2014, these agreements became more expensive for Algeria.

The high transit tariffs have to a certain degree created a precedent outside the EU regulated area, where there are no explicit transit fees.

As the existing transit agreements from Algeria are about to expire, this will be a good opportunity to renegotiate in accordance with the EU system and create incentives to bi-lateral trade. There will still be the benefit of economics of scale by combining transit and bi-lateral trade.

In general this demonstrates that there is a lack of recognized procedures for quantifying the reasonable benefits of being a transit country. The principles from the Energy Charter Treaty and from EU system could be used.

Technical barriers and constraints for production and transportation

Technical barriers include a number of issues from production to end user. On the production side, constraints include management of the reservoirs, development of deep water fields, associated gas and gas quality and quantities, environmental impact from e.g. high sulphur fields, availability and/or treatment of water. The barriers vary from country to country. For the present study we find that some of the most important issues are:

- Qatar – reservoir management of the North Field being one of the reasons for the moratorium on further gas export from the field;
- UAE, Kuwait, KSA, Iraq – high sulphur content in the gas and need for expensive treatment and handling of large volumes of sulphur as by-product;
- Egypt – deep-water field development;
- Algeria, Libya – distance from smaller gas fields to gas infrastructure.

On the transportation side some of the technical and economic barriers which have been identified include:

23) Deep water pipeline limitations. This was originally the reason for pipeline export to Italy and Spain from Algeria via Tunisia and Morocco. This barrier is now much less important which opens the possibility of a number of new pipelines such as those from Egypt to the EU, Cyprus and Israel to Egypt, Saudi Arabia to Egypt on a southern route and from Oman to India. Nevertheless, the direct route from e.g. Egypt to Italy is impossible due to very large water depths.

24) Onshore pipeline pressure has traditionally been limited to around 100 bar: This requires the establishment of compressor stations with a spacing of 2-300 km. If a high pressure offshore pipeline of up to 200 bar was also used onshore, the spacing for compressor stations could be up to 1000 km. As some of the potential major pipelines will have to cross deserts over long distances there will potential cost reductions in opting for high pressure pipelines

25) Pipeline dimensions and economics of scale for pipelines: As the cost of a pipeline is approximately proportional to its diameter, and capacity is proportional to diameter to the power of 2.5, there are huge economies of scale by using large diameter pipelines. At present the maximum practical dimension is about 56” but it is also possible to run 2 or more pipes in parallel, which also reduces costs. Many of the pipeline connections proposed in the past had much smaller diameters resulting in high unit transportation costs. In order to improve economies of scale it is important to coordinate long distance transportation rather than build infrastructure for individual fields or smaller markets. This will favour major transport corridors from e.g. Qatar to North Africa.

26) Pipeline routing is a complex task and includes aspects such as distance, terrain, right-of-way, seismic activity, geotechnical conditions, environmental and heritage impact, risk for sabotage etc. Here offshore gas pipelines may in some cases be easier to establish than onshore pipelines.

Underground gas storage can be used to balance gas use seasonally and as security of supply. So far very little work has been done to identify locations for underground gas storage, but a number of countries have depleted gas fields which could be used.

LNG import facilities can be onshore plants with concreate tanks or offshore floating regasification units. The advantages of FSRU are that they can be established rapidly and can be moved to other locations if and when domestic production or pipeline supply replaces the need. In this way it will be possible to avoid stranded cost. Another technical barrier for LNG is the need for port facilities which are expensive and time consuming to establish on wave-exposed coasts, this favours the use of existing harbour facilities.

Lack of transparency of data
In most of the countries in the region it is difficult to get access to data which is critical for creation of a reliable market and bilateral trade. Data on gas is mostly shared under the umbrella of OPEC in OAPEC, the Gas Exporting Countries Forum, GECF, while the Arab League is focuses mostly on the electricity sector. Apart from this, data is owned by the IOC´s operating in different countries, which results in a biased negotiation situation.

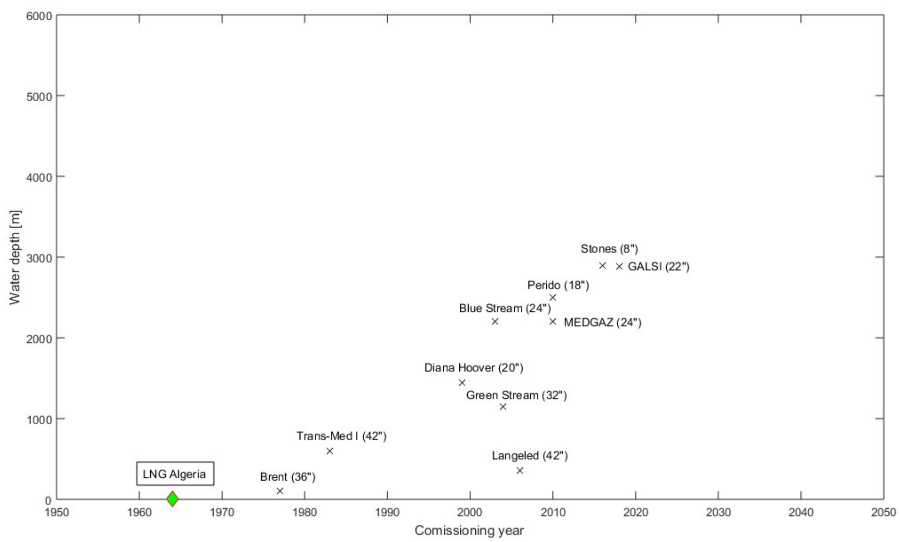
As a pre-requisite for establishing regional cooperation and trade it will be necessary to share data about:

- Gas consumption by sector – preferably on monthly basis
- Gas production by field on monthly basis
- Daily gas demand and flow in major pipelines
- Gas reserves and new finds on yearly basis
- Gas prices on monthly basis

Geographical barriers coming down
Historically there has been a limit to how much gas could be traded and exported due to the lack of possibilities for constructing infrastructure at affordable costs. In the early 1960’s the feasibility of installing a pipeline between the North African and the European continent was explored. At the time it was deemed too challenging to cross the waters in the western part of the Mediterranean Sea with depths of 1,000 meters and an LNG export terminal was built and commissioned in Algeria in 1963 instead. Additionally these physical barriers, in the form of water depths, meant that the Mahgreb Europe pipelines, which export gas from Algeria to Spain and Italy, had to transit via Morocco and Tunisia respectively. With today's technology this would most likely not have taken place – a fact best illustrated by the MEDGAZ delivering gas directly to Spain from Algeria. Thus the current supply situation in Morocco and Tunisia for example is a

result of the physical barriers surrounding the region. However, over the years technical advances made offshore pipelines an attractive alternative to LNG transport when transporting large quantities of gas due to the very low operational expenditure compared to LNG tankers and facilities. This technological advance in how deep waters offshore pipelines can be installed can be seen below in Figure 26 where water depths have been plotted against commissioning year for some of the known offshore projects.

Figure 26: Development off installation depths for offshore pipeline



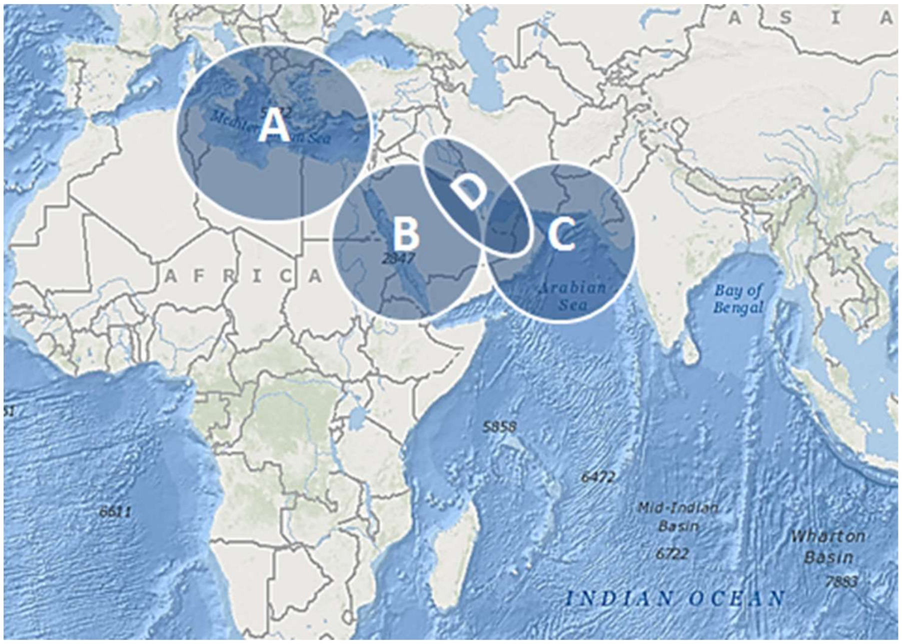
Source: Ramboll

After 1963, when it was not feasible to cross the western part of the Mediterranean, the advances in the depth of offshore transmission pipelines have been extensive but it is only after 2005 where Green Stream and Blue Stream where commissioned that the deep water gas pipelines reached transmission pipeline diameters. The deepest pipelines in the chart are the 8" stones gas pipeline, which is already installed in the Gulf of Mexico, and the 22" GALSI offshore pipeline which is still in the planning phase and not yet decided. These two pipelines indicate the current limits of the water depths in which offshore pipelines are feasible but there is nothing to suggest, as discussed later in this chapter, that pipeline technology will not advance as much in the next 20 years as it has in the past.

6.5 Offshore pipeline possibilities - overview

Pipelines should be seen as an alternative to LNG. When transporting large quantities of gas they often prove more feasible compared to LNG. For the Pan-Arab region there are a number of trade and export possibilities via pipelines. It is a choice between transporting the gas onshore through various countries exclusive economic zone or alternatively, installing offshore pipelines which are safer in terms of third party interaction. The following sections illustrate the water depths in possible export location for the Pan-Arab gas and advances in offshore pipeline technology as LNG facilities are most often limited by economic feasibility and not technical obstacles.

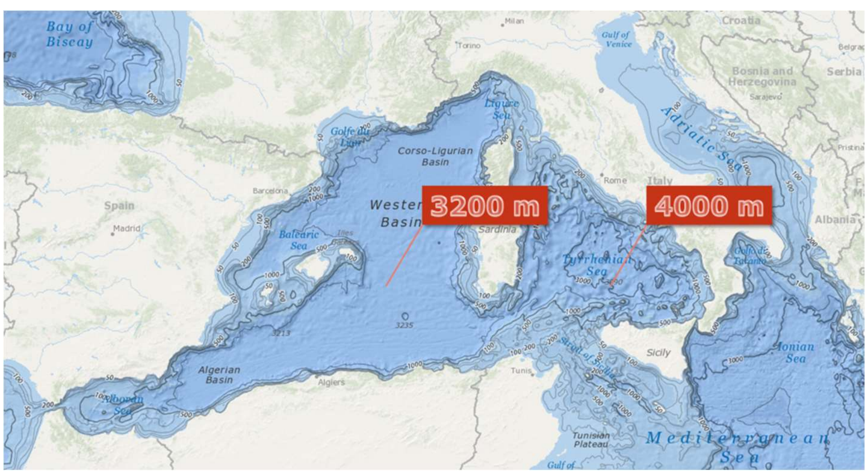
Figure 27: Possible export pipeline crossing



Source: National Centres for Environmental Information (NOAA)

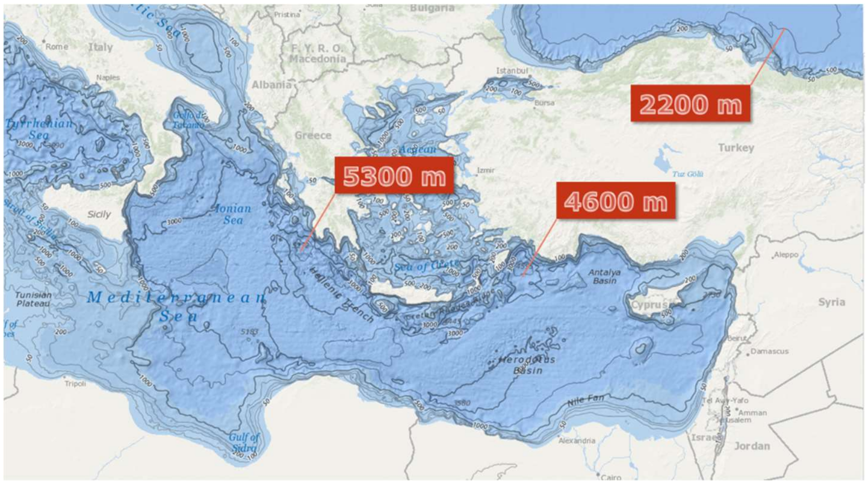
Figure 27 indicates four areas which need to be crossed in order to either trade gas within the MENA region or export to Europe, the Mediterranean (A), Red Sea (B), India Ocean (C), and the Persian Gulf (D).

Figure 28: A1 Western Mediterranean Basin



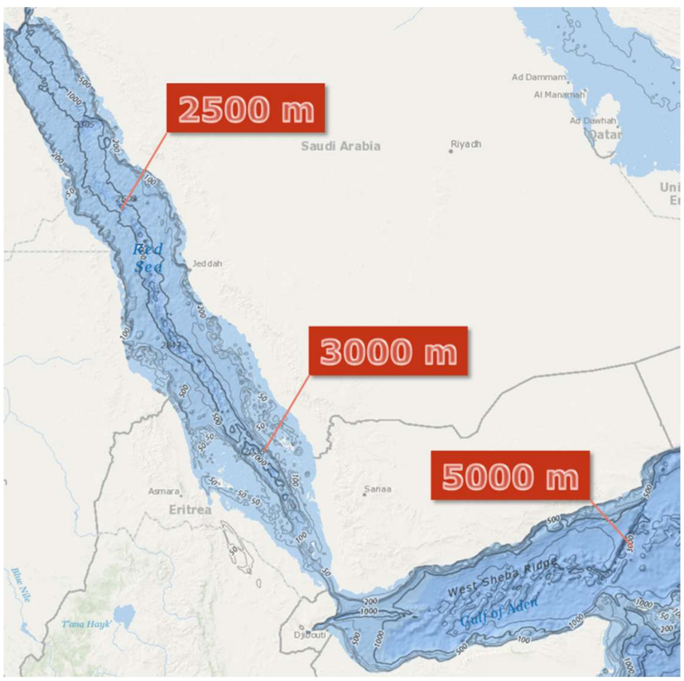
Source: National Centres for Environmental Information (NOAA)

Figure 29: A1, Eastern Mediterranean Basin



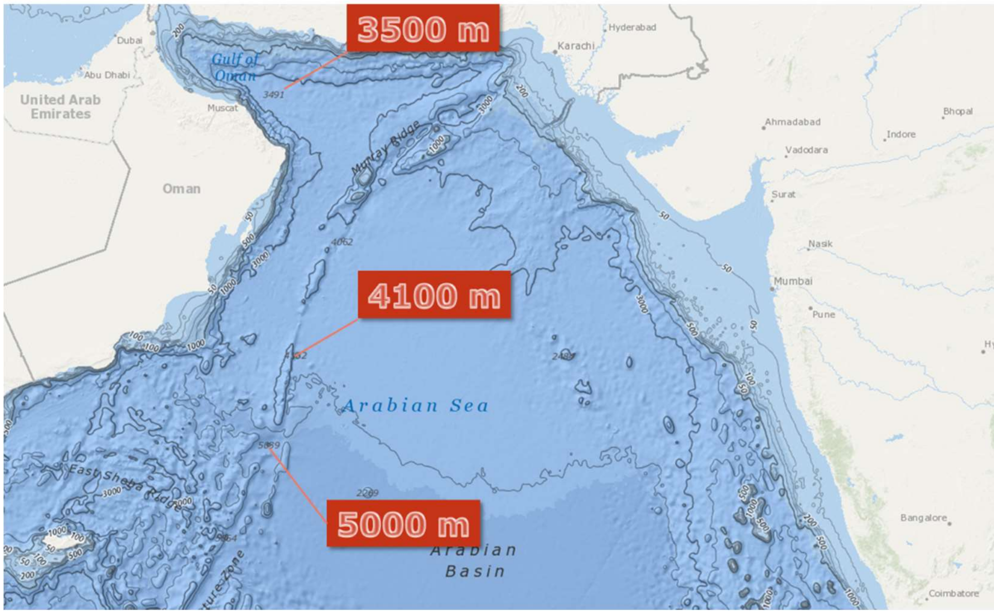
Source: National Centres for Environmental Information (NOAA))

Figure 30 - B, Red Sea



Source: National Centres for Environmental Information (NOAA)

Figure 31 C: Arabian Sea (Source: National Centres for Environmental Information (NOAA))



Source: National Centres for Environmental Information (NOAA))

Figure 32 D: Persian and Arabian Gulf

(Source: National Centres for Environmental Information (NOAA))

Area A and area C, where new export pipelines out of the region would have to be placed, have areas were slopes exceed the reach of today's pipeline technology. However it may be possible to find routes circumventing these slopes. Water depths in the Red Sea do not exceed 3,000 meters in the inner waters and it is possible to choose a route with a maximum water depth of 2,500 meters. Area D, the Persian/Arabian Gulf, is very shallow with a maximum depth of 136 meters and no obvious obstacles for offshore interconnections appear to exist.

Thus we conclude that Red Sea crossings could be possible with today's technology. Routing in the Mediterranean is challenging and would need to circumvent the deep areas offshore Greece and Italy.

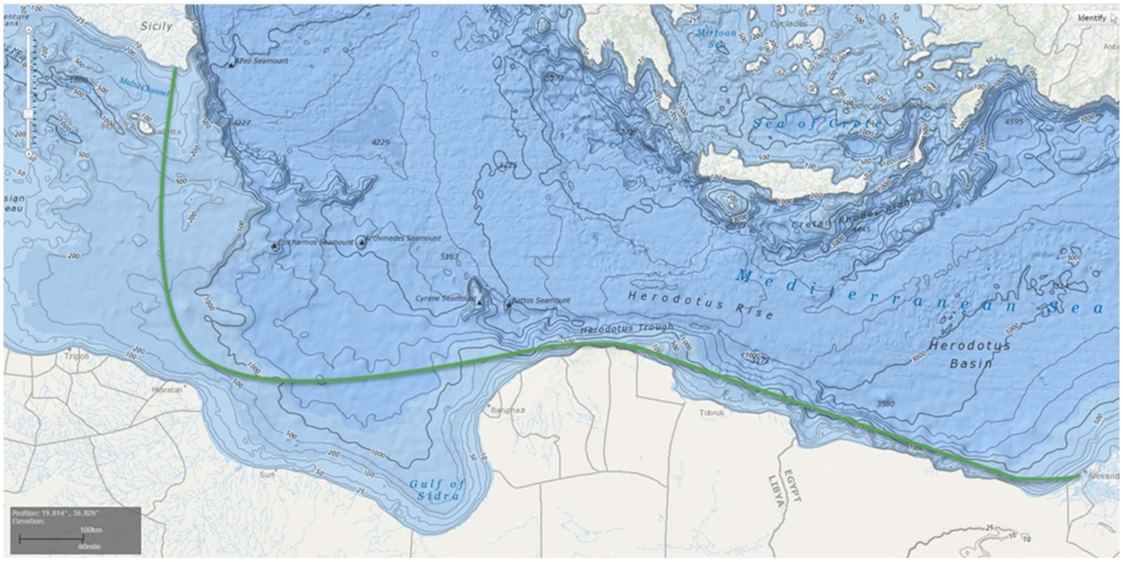
Offshore pipelines connecting Egypt directly with Europe

With Egypt an energy hub, it would be natural to build a direct pipeline from Egypt to Europe. Because the waters between Greece and Egypt are rather deep (3,000-5,000 meters), it could prove more viable to install an offshore pipeline along the coast of the African continent, crossing the Mediterranean between Libya and Sicily.

Such a nearshore pipeline solution is more realistic, and comparable in CAPEX, than an onshore pipeline through Libya. A central onshore gas transmission pipeline would risk becoming a target of various political disputes and possible attacks. In addition, there might also be a rather large scope related to the right of way onshore.

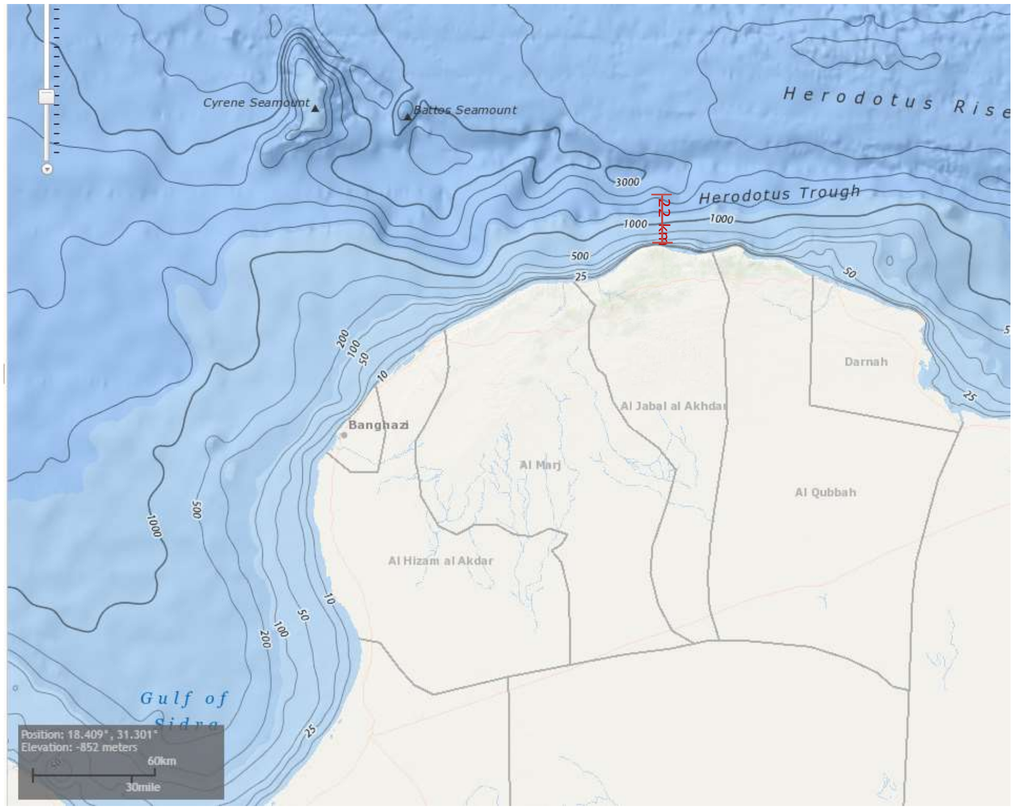
An offshore pipeline can be installed 12 nautical miles (22.2 km) from the coast to avoid the territorial belt considered to be sovereign territory of the state (in this case Libya) as per the United Nations Convention on the Law of the Sea. At the same time to reduce the CAPEX, and to be able to use proven technology, the pipeline route should be kept within waters that are below 2,000 meters deep. This is achievable with the route proposed in Figure 33. This route has a length of approximately 1,500 kilometres.

Figure 33: Egypt to Italy pipeline



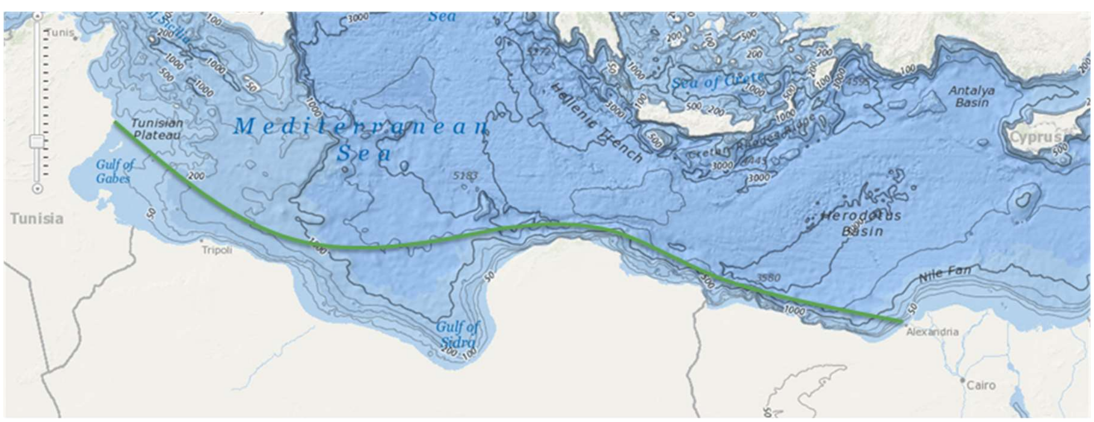
The part of the route where the pipeline is closest to the shore is north of Libya by the Al Jabal Al Ankhdart region. As shown in Figure 34, the pipeline will be just within the 2,000 meters contour in the narrowest part of the route while staying outside sovereign territorial waters.

Figure 34: Route point outside Libya



As an alternative to a pipeline to Italy, a pipeline to Tunisia could be considered. This could serve both the North African market and Europe through existing pipelines to Europe. This route (as shown in Figure 35) is approximately 1,500 kilometres long.

Figure 35: Egypt Tunisia offshore



Other geographical restrictions remain however, including:

- Yemen: Oil and gas fields are located inside the country while the vast majority of people living along the coast in urban areas. Attempts have been made by the WorldBank and private investors to unlock the gas reserves but so far with no success. However the main barrier is not geography but the access to reserves and the security needed to attract

international firms. The only experience Yemen has, with LNG being exported out of the country, is not a good example to follow.
- Algeria, Libya, and partly Egypt. Fields may be far away from consumption centres along the cost and export terminals. Thus additional costs must be incurred to evacuate and monetize the gas.

Overall energy policy including climate policy
The overall energy policy impacts the need for export and import of natural gas. The main discussion issues in the MENA region have been:

27) nuclear power in Iran and Saudi Arabia
28) renewable energy in Morocco, Algeria, UAE, Egypt and Saudi Arabia
29) Gas to Liquid production in Qatar
30) Gas for transportation in Iran
31) Oil for power production in Saudi Arabia
32) Gas in the petrochemical industry in Saudi Arabia, Qatar, Algeria
33) Local pollution in cities
34) Water use and water production

A potential gas importing country like Morocco is making rapid progress in the use of renewable energy such as wind and solar combined with hydro power. A gas exporting country like Algeria can increase export by adding renewable energy made possible by the vast amount of space available in the country. The climate issue also impacts the use of fossil fuel. Most MENA countries are themselves exposed to climate change as global warming may severely affect living conditions. The following MENA countries have signed the Paris agreement: Algeria, Morocco, Saudi Arabia and Palestine.

While the renewable energy agenda could be a driver for more gas it could also impact the need for gas in the power sector, reducing gas used during peak loads during the day for example. The expectation however must be that the demand for oil will be hit first.

7. SUBSIDIES

7.1 Introduction

The purpose of this chapter is firstly to provide an overview of the status with respect to the implementation and progress of subsidy reforms. Secondly the chapter presents preliminary conclusions with respect to the potential of gas sector subsidies constituting barriers to trade amongst the MENA countries.

7.2 Subsidies generally

7.2.1 Size of subsidies

IMF estimated that almost half of all global energy subsidies are in the MENA region. Energy price subsidies are the main tool to provide social protection and share hydrocarbon wealth in the region and far exceed the value of other subsidies.

7.2.2 Effects of subsidies

The effects of energy subsidies are well-known. When natural gas prices are subsidized, it leads to rapid growth in gas and electricity consumption as gas is one of the main fuels for power generation. Subsidized gas prices keep electricity prices low, often benefiting higher income households the most as they use more electricity. However, low income households also benefit from subsidies and are the most vulnerable to change.

Low natural gas prices lead to underinvestment in the energy sector and even in countries where producers and transmission and distribution companies (often the National Oil and Gas Company) are compensated in the state's fiscal budget, the payment is often not large enough to invest in new production and infrastructure, resulting in fuel shortages. When international energy prices go up, energy subsidies lead to a rapidly rising fiscal burden in gas importing countries. Exporting countries also incur a cost, in the form of foregone revenues that could have been invested in new infrastructure or other government programs.

With low oil and gas prices, exporting counties may experience difficulties financing low indigenous prices and the focus on subsidies therefore change from importing to exporting countries.

Energy subsidies tend to increase consumption creating higher global prices. Naturally energy importing countries take the view that subsidies should be abolished.

Some energy resource-rich economies have voiced the opinion that the reference price in their markets should be based on their cost of production, rather than prices on international markets. The basis for their view is typically that natural resources are being used to promote their general economic development, and that this approach more than offsets the notional loss of value by selling the resource domestically at a price below the international price. The counter-argument is that such an approach results in an economically inefficient allocation of resources and reduces long-term economic growth[5].

7.2.3 Methods for measuring subsidies

There are several ways to measure subsidies. The Price-Gap Methodology measures the price difference between a free-market reference price and the actual retail (end-use) price for a given product. Both the IEA and the IMF use this methodology, but with different results as the assumptions differ. The choice of reference price is particular important to the outcome. Another issue is whether to include externalities, such as environmental costs (See Box 4)

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[5] www.worldenergyoutlook.org › Resources › Energy Subsidies

Box 4: Methods for Estimates of Energy Subsidies

Methods for Estimates of Energy Subsidies
The International Energy Agency (IEA) reports its estimate of global energy subsidies in its annual World Energy Outlook. This estimate is based on the price-gap approach, which compares the end-user prices with reference prices. The reference prices consist of the supply cost inclusive of shipping cost and margins and any value-added tax.

The IMF also adopted the price-gap approach and provides subsidy estimates based on two definitions of energy subsidies. Pre-tax subsidies compare consumer prices with reference prices. Using pre-tax prices, however, does not account for the environmental damage caused by high energy consumption. Post-tax subsidies compare consumer prices with supply cost plus the efficient level of taxation which includes an excise component for externalities and a consumption tax component for revenue considerations and result in much larger subsidies. (Post-tax subsidies are not included in this report).

The IMF pre-tax subsidy estimates are different from the IEA estimate as they use different reference prices. Another reason for the difference is that the IEA estimate includes some tax subsidies.

The estimate by the Organization for Economic Co-operation and Development (OECD) is based on the so-called inventory approach. This method focuses on direct budgetary support and tax expenditures that provide a benefit or preference for fossil-fuel production or consumption. The OECD estimate is much smaller than those of IEA and IMF, partly because it only covers advanced economies. The IMF also accounts for explicit subsidies in government budget in its country reports.

Source: IMF Working paper WP/15/105: How Large Are Global Energy Subsidies? 2015.

7.2.4 Study approach: Price Gap

In this study we are applying the Price Gap Methodology to estimate energy subsidies.
To monitor energy subsidies based on the Price Gap Methodology the following formula is used:

$$\textit{Subsidy} = (\textit{Reference price} - \textit{End-user price}) \times \textit{Units consumed}$$

For economies that export gas but charge less for it in the domestic markets, the domestic subsidies are implicit; they have no direct budgetary impact so as long as the price covers the cost of production. The subsidy in this case is the opportunity cost of pricing domestic gas below international market levels, i.e. the rent that could be recovered if consumers paid world prices, adjusting for differences in variables such as transportation costs. For net importers, subsidies measured via the price-gap approach may be explicit, representing budget expenditures arising from the domestic sale of imported gas at subsidised prices, or may sometimes be implicit. Many economies rely extensively on domestically produced gas, but supplement domestic supply by importing the remainder. In such cases, subsidy estimates represent a combination of opportunity costs and direct expenditures[6].

[6] www.worldenergyoutlook.org › Resources › Energy Subsidies

Box 5: Challenges and limitations of the Price-Gap Methodology

Challenges and Limitations of the Price-Gap Methodology
The report relies on estimations of market price differentials, or price-gaps, for various sources of energy. It should be recognized that this method relies on a number of assumptions:

1) Identifying the appropriate cost. Many different measures of cost exist, including average cost, marginal cost and opportunity cost. Exporting countries with large energy endowments prefer to use cost of production as a benchmark. What is more, energy costs are highly variable as not all commodities are widely traded.

2) Identifying the appropriate price. Although the price quoted in global markets is typically used as a measure of opportunity cost, international prices may be distorted by a variety of factors and can experience a high degree of volatility.

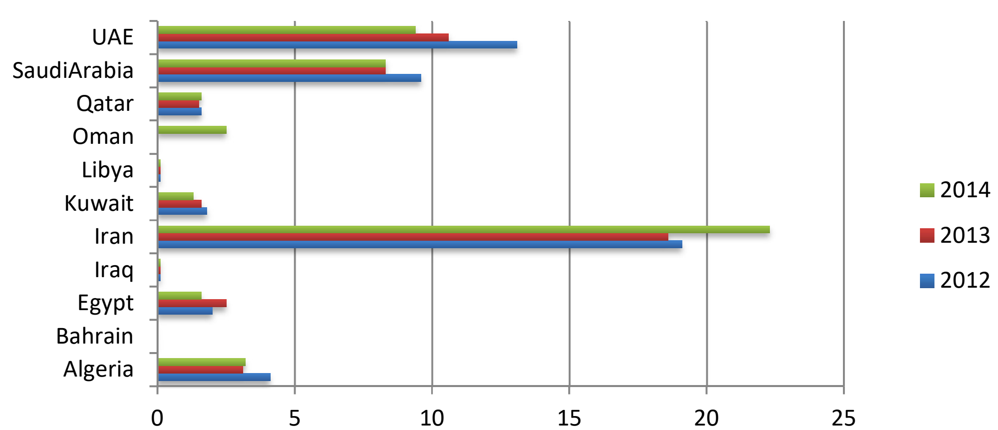
3) Price-gap estimates do not capture producer subsidies. Therefore, subsidy estimates based only on price-gap measurements tend to underestimate the level of subsidies in developed countries.

Source: IEA, OPEC, OECD, WORLD BANK, JOINT REPORT 2010.

7.3 Trend in subsidies in the MENA region

The focus on energy subsidies has increased since the G-20 asked the IEA, OPEC, OECD, and World Bank to provide an analysis of the scope of energy subsidies and suggestions for the implementation of an initiative to "reduc[e] fossil fuel subsidies while preventing adverse impact on the poorest", and to "rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption" in 2009[7]. As a result, many countries have increased their domestic energy prices thereby reducing subsidies and in some cases eliminating them.

Figure 36 Gas subsidies in key MENA countries 2012-2014, Real 2013 BUSD



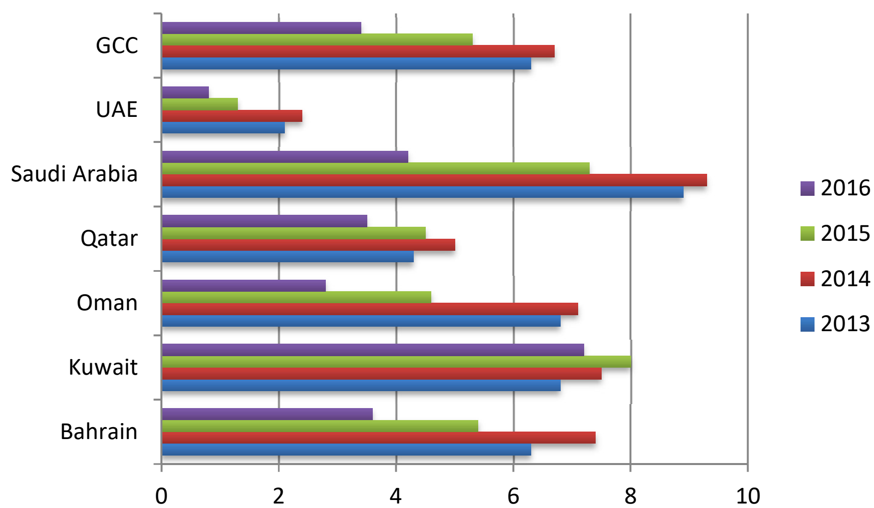
Source: IEA Subsidy database.

[7] *Analysis of the scope of energy subsidies and suggestions for the G-20 initiative* . IEA, OPEC, OECD, WORLD BANK, JOINT REPORT 2010.

The focus on energy subsidies has increased since the G-20 asked the IEA, OPEC, OECD, and World Bank to provide an analysis of the scope of energy subsidies and suggestions for the implementation of an initiative to "reduc[e] fossil fuel subsidies while preventing adverse impact on the poorest", and to "rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption" in 2009. As a result, many countries have increased their domestic energy prices thereby reducing subsidies and in some cases eliminating them.
Figure 36 shows that gas subsidies in 11 key MENA countries, calculated by the price gap method fell from 2012 to 2014 (with the exception of Iran).

The price gap approach make the subsidies depending on the actual global energy prices thus obviously the fall in oil and gas prices in the second half of 2014 have impacted the 2014 figures.

Figure 37: Energy subsidies in GCC countries, 2013-2016. % of GDP



Source: IMF:Regional Economic Outlook, Oct. 2016

IMF Energy Price Reforms in the GCC—What Can Be Learned From International Experiences? Nov. 2015

Figure 37 shows IMF estimates of energy subsidies using the price gap method for GCC countries 2013-16 as a percentage of GDP. The benchmark is U.S. pre-tax prices. It shows that the downward trend in subsidies has continued helped by lower oil prices.

7.4 Timing of regulatory activities

It is clear that not all gas consumers are ready or able to pay market prices. Thus phasing out subsidies cannot be done overnight and requires some protection of poor consumers, careful planning, and public information campaigns. The choices available for introducing market based pricing for some parts of the market require a number of regulatory steps and initiatives. A key issue to decide is the timing of the revisions to the regulatory framework, the restructuring of the gas sector and the price increases to cover the higher costs of future gas supplies. Changes to the legal and regulatory framework require:

- implementation to define the policy and long term strategy framework
- market reform to gradually opening up the market to competition.
- pricing reform
- changes to regulations and roles and responsibilities of companies.
- unbundling of trade and transportation activities in the gas sector.

Bearing in mind that countries are different a number of short term actions could be taken.

1. **Primary Gas Market Law:** Decide policies and responsibilities for the regulator, gas transmission companies and independent transmission and distribution pipelines within the primary gas sector legislation
2. Determine eligible customers to buy deregulated, market based priced gas
3. Determine the regulators additional responsibilities regulating TPA to pipelines to promote competition in the gas market
4. Unbundle/create transmission and distribution companies
5. Develop TPA rules for transmission and distribution systems, and LNG terminals

Developing primary gas sector legislation is not necessarily something which will take many years – however often it is politically sensitive which can prolong the process.

In the medium term, once the primary legislation is developed all related secondary legislation including drafting of a network code for Transmission and Distribution pipelines and storage must be initiated. This can be a time consuming exercise - but it is important to be aware that no country get it 100% right the first time. Network codes in most EU countries are revised, amended, and changed over time, and often several times during a year to reflect market developments and technical conditions. Sometimes it is actually easier to start from scratch than to develop on a legacy document.

Box 6: Case study on market reforms and introduction of deregulated gas prices - Pakistan

Pakistan projects a strong increase in gas demand over the next decades, and domestic gas production is expected to decline if no new discoveries are made. In 2015, the gas deficit was around 20 bcm (2 bcf/d) and it is expected to triple.

The Government of Pakistan has been assessing the performance of Pakistan's natural gas sector and developed options for the future direction of the sector towards a competitive and deregulated sector with increased private sector participation and LNG imports. This would among other things involve overcoming the current barriers to selling directly to customers at prices that are higher than today and at the same time fully cover costs, including future gas supply and LNG imports. The separation of trading and infrastructure operations and transmission and distribution are important options to remove barriers to competition.

In general, options include:
Establish two markets for gas: The current low priced gas supplied by SNGPL and SSGC to their customers at regulated prices and a market for new gas supply at (higher) deregulated prices.

How to introduce LNG imports?

1) As a private sector import at unregulated prices sold to customers willing to pay the price?
2) Or introducing regulation of the price for LNG?
3) Introduce a single buyer in the form of a transmission company, aggregating supplies from various sources and at different costs and reselling at regulated prices

7.5 Conclusion on subsidies

There is a movement in the MENA region towards reducing energy subsidies to reduce the fiscal burden on government budgets and to take advantage of the low oil and gas prices to phase out subsidies, in particular for petroleum products that carry the heaviest burden on government budgets. In many countries the reduction in petroleum product subsides has been combined with the introduction of an automatic adjustment of petroleum prices (weekly, monthly or quarterly), so that the effort is not eroded by a return to a higher international oil price level.
Electricity prices however are still low in most countries in the region, so that the power utilities either need low gas prices or a budget transfers from the government to be financially sound.

- A group of gas importing (or soon to be importing) countries *Morocco, Jordan, Lebanon*, with a small indigenous gas production, importing gas at international/regional prices for power generation. As a result they have minimal or no gas subsidies that would pose a barrier for future gas trade. They have also removed petroleum product subsidies, but low electricity prices require explicit transfers to the power utility, which is not sustainable and pose a threat to the Budget.

- A group of countries, *Algeria, Egypt, Iran, Iraq, Saudi Arabia, Qatar* with large gas reserves, exporting gas (or with a potential to export gas) and domestic gas prices below the international benchmark (i.e., a subsidy measured by the price gap method). This could discourage investments in E&P and expansion of gas production and could pose a barrier for future gas trade, in particular if there is a risk the production is diverted to the domestic market where gas prices are low. These countries have begun the removal of petroleum product subsidies but this is on hold in several countries and they have a long way to go before reaching international levels and none of these countries have an automatic adjustment of fuel prices. With the exception of Saudi Arabia these countries also have low electricity prices, thereby putting a constraint on government finances and foreign exchange reserves.

- *Oman*, *Kuwait, UAE, Tunisia* and soon *Bahrain* fall in between these two groups: They are importing gas at international/regional prices, and have indigenous domestic gas production (and Oman and Abu Dhabi export LNG). Gas prices are below the international benchmark in Kuwait, UAE and Tunisia, which could discourage investments in new gas domestic production but would not be a barrier to gas trade, provided it is based on international fuel prices. Only Oman and UAE have eliminated petroleum product subsidies and in Oman gas prices have reached an international level. With the exception of UAE electricity prices are low.

Below in Table 14 an overview of the applicable subsidies and the potential phase out is presented.

Table 14: Phase out of subsidies over time

	Subsidy removal programs for gas		Elimination	Financial gas price	Projected prices based on today's reforms		
	Efforts to date	Target level of subsidies	Target date	USD/MMBtu	2020	2025	2030
Algeria	Minimal	no	no	0.5 - 0.6	0.5 - 0.6	0.5 - 0.6	0.5 - 0.6
Morocco	Not subsidized			reg/int.	reg/int.	reg/int.	reg/int.
Tunisia	Planned	no	no				
Egypt	Initial increases in 2014,	Originally 100% reduction ,	2019	ind. 3-8, HH 1.7-6			

	but halted	now 70%					
Jordan	Not subsidized			6 (import price)	import price	import price	import price
Lebanon	Not subsidized			5 (import price)	import price	import price	import price
Iran	Further increases in 2015	90 percent of international prices	2015	2	90% of Int.	90% of Int.	90% of Int.
Iraq	Minimal	no	no				
Kuwait	Minimal	no	no	1,5	1,5	1,5	1,5
Bahrain	Not subsidized	n.a.	2021	2,5	3,5	4	4
UAE	None	no	no	1.25-1.30			
Saudi Arabia	Gas price increased recently	committee decides	over 5 years	1.25-1.50	cost rec?		
Qatar	None	committee decides	no	0,75	0,75	0,75	0,75
Oman	Not subsidized			3	market price	market price	market price
Yemen	None	no	no				

8. VALUE OF GAS AND COST OF SUPPLY OF GAS

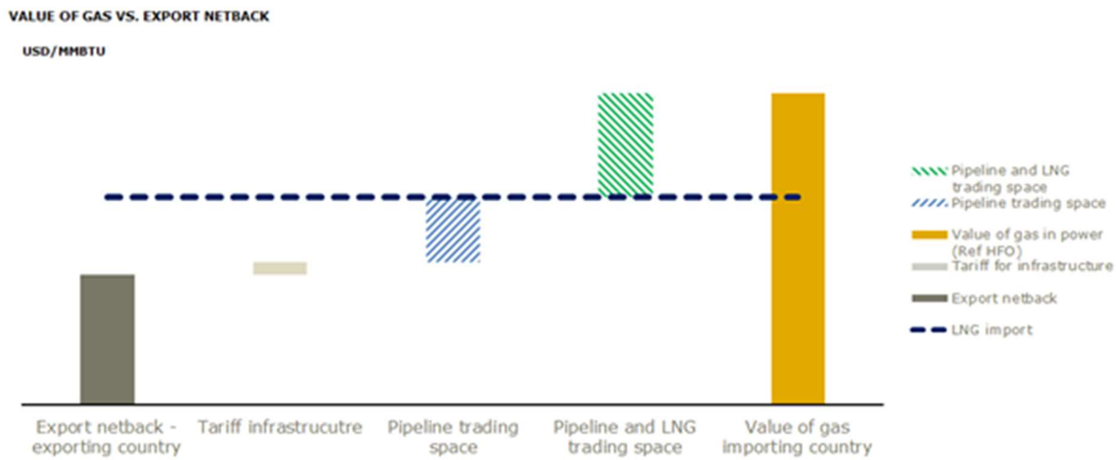
For each country we are pursuing a number of benchmarks for assessing the actual value and cost of gas. This is important in order to explain the possible trade possibilities between countries. Some countries will be endowed with large resources and low cost of producing them while others may not be in the same position but have a high value from consuming gas. In this chapter we first investigate well head production costs from a number of fields across the region. To understand the level of subsidies we relate the identified wellhead costs to the subsidised prices and the price of import.

Secondly we look at both the producer side and the consumer side. For each country we assess the value of gas. For producers this means asking what would be the most economical use of the gas after having satisfied domestic consumption. Exporting as LNG or by pipeline out of the region? Or trading with countries within the region? To shed light on these questions we calculate netback prices for the major exporting countries and for countries with the prospect of becoming exporters, Iran and Iraq in the long term. This approach indicates the lower limit to which producers would be willing to sell gas, any price above would leave them better off.

Taking the consuming country's point of view we investigate the value of gas in the power sector. This sector has traditionally been the highest value sector for gas. We benchmark gas against both HFO and coal in the power sector, considering both new power plants and conversion of existing HFO to gas. This approach indicates an upper limit for how much a power producer would/should be willing to pay for gas if the alternative was HFO or coal.

In between the lower bound, the netback from export, and the upper bound value of gas in the power sector, we expect to find a trading space, defined as the area where both sellers and buyers are better off by engaging in trade.

Figure 38: Value of gas vs netback in export.



Source: Ramboll

8.1 Wellhead production costs - Long run marginal costs

Most countries examined have substantial existing production, which is likely to be inexpensive in the short run. The costs are already sunk and probably repaid, while many fields are onshore. However to maintain supply from such fields, substantial CAPEX commitments may be necessary, and only part of the costs can be regarded as sunk. Additionally, several of the countries in the region are challenged by fields with high sulphur content for example the LRMC of domestic gas production in the UAE was estimated at USD 5-6 /MMBTU[8] back in 2011. Thus when assessing future marginal costs of domestic supply, we suggest examining the development costs in terms of CAPEX and OPEX of the 4-5 largest new gas fields for each country, if possible. Such estimates are obviously most important for countries with large reserves. As an example, the future pricing in Iran would be driven by the cost of developing the South Pars gas field and not the average or short run marginal cost of current production. The chosen methodology for converting reserves, CAPEX/OPEX into breakeven prices is described in Box 7 below.

[8] OIES: Natural Gas Markets in the Middle East and North Africa. 2011

Box 7: Calculating breakeven prices for individual fields

Calculating breakeven prices – sources and assumptions
Data such as start year, plateau year and production level are gathered from the companies involved in the development of the fields as well as from government sources.

CAPEX data is gathered mainly from company reports and industry sources. When no CAPEX data has been available, CAPEX estimations have been based on major gas projects in the MENA sanctioned over the last few years. When not specified for a project, the time distribution of CAPEX spending has been based on existing major petroleum projects.

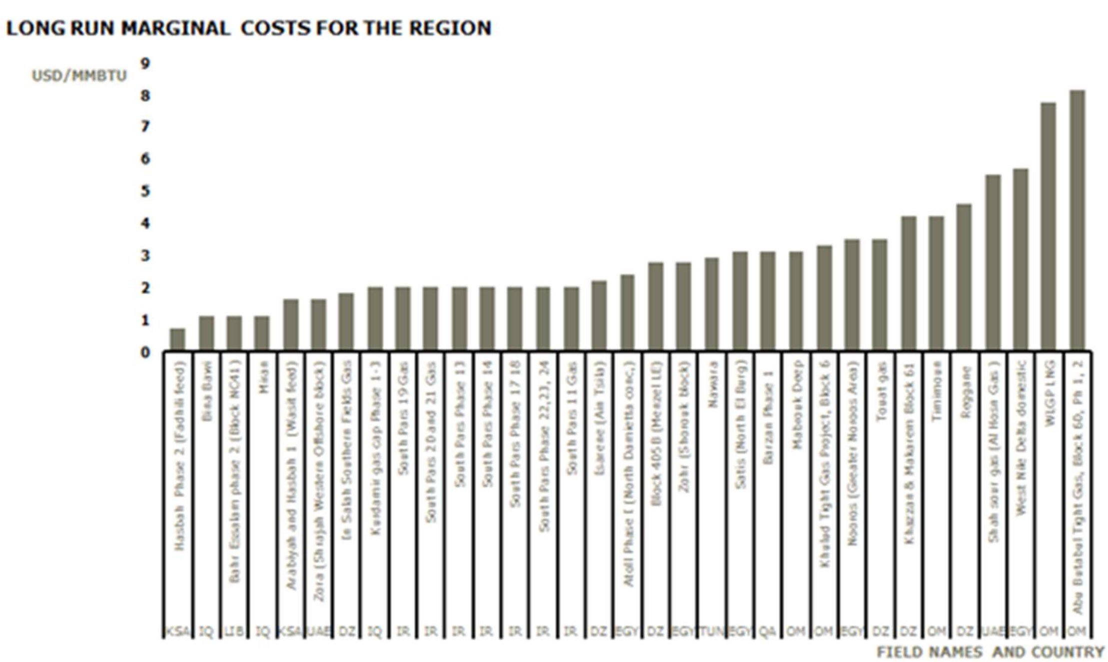
OPEX data is from company sources when available, with estimations based on similar field developments worldwide. OPEX varies from field to field depending on the size, geological conditions and the degree of technical complexity. OPEX are divided in variable OPEX and fix OPEX.

It should be noted that CAPEX figures are not always straightforward and can carry different elements across companies and countries such as associated export infrastructure. Additionally, some countries only have one or two few fields planned
A WACC of 10% have been used.

A full list of references can be found in Appendix 2

Figure 39 below presents the well head production costs identified in terms of new fields for the entire region.

Figure 39: LRMC Wellhead costs Mena Region



Source: Ramboll

Lo cost production is primarily in Iraq, Saudi Arabia, Iran, while higher costs are found in Oman, UAE, and to some extent Egypt and Algeria.

8.2 **Import benchmark**

For importing countries or countries that may potentially import natural gas in the future, a useful ceiling reference price would be the cost of importing LNG from world markets, which consists of a forward LNG curve plus the cost of infrastructure to enable the imports, such as regasification plants.

Since many of the MENA countries are contemplating on importing LNG we derive at a very simple forward curve from the above including the following infrastructure elements and their associated costs.

The forward curve based on US export benchmark would consist of:

henry hub price + liquefaction + shipping (US to MENA region) + regasification.

Table 15: Value chain costs

	US export benchmark
Liquefaction	3.5 USD / MMBTU
Shipping US to MENA	1.0 / MMBTU
Regasification (existing land based terminals)	0.5 USD / MMBTU

Source: LNG Markets in Transition: The Great Reconfiguration own assumptions.

Assuming that the US LNG development would constitute a lower bound i.e. if prices rise, LNG from the US from would enter. This leads to a simple forward curve as illustrated in Table 16

Table 16: US LNG Forward Curve

	US Henry Hub	Value Chain costs*	Total price
2016-2020	3	5	8
2021- 2025	4	5	9
2026-2030	5	5	10

*As a simplifying assumption we keep this constant over the years

A recurring discussion is the treatment of sunk costs and whether costs of liquefaction be included or not, as once built the terminal cost could be considered as sunk. Without the terminal costs elements prices would be significantly lower. Sunk costs are not assumed relevant to US exports –the already established export terminals in Algeria and Qatar are considered sunk.

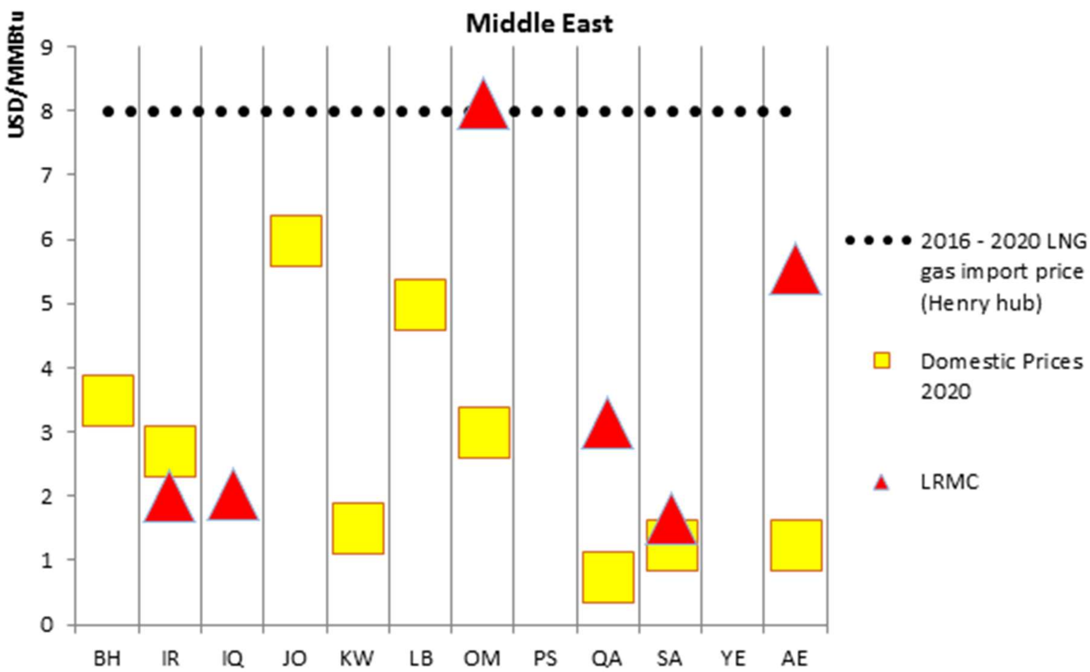
As the possibility of Qatar supplying its neighbours has opened up with the lifting of the moratorium it may be instructive to calculate a netback based on supply from Qatar. Considering a market price of 5 USD/MMBTU in Europe in 2020 and the associated transport and regasification costs of 1 USD/MMBTU, netbacks in Qatar would be around 4 USD/MMBTU taking into consideration sunk costs of liquefaction in Qatar[9]. Transport from Qatar to any MENA country would be lower than the transport cost to Europe, thus delivered gas from Qatar could be lower in the range of 5-6 USD/MMBTU.

In Figure 40 the identified domestic subsidised prices from Chapter 10 are compared to the identified well head costs and the LNG import price. The figure shows that the subsidised prices

[9] If the added expot comes in the form of new LNG trains it would not be possible to consider the liquefaction as sunk.

are below the economic prices and sometimes below the cost of production. The exception is Iran which has undergone a price reform and has low LRMC for field development.

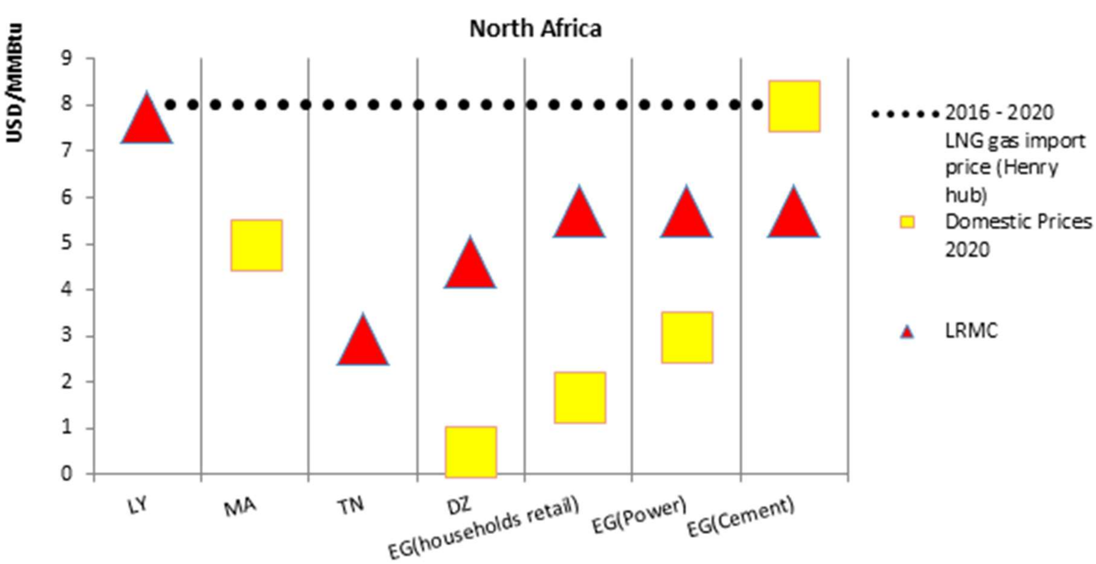
Figure 40: Middle East LRMC, LNG import, and subsidised prices (2020)



Source: Table 14 and Figure 39.

Domestic subsidised prices are expected to increase from 2020 in some countries (as shown in Table 14 in the previous chapter). The picture is the same for North Africa with the exception of Egypt, where domestic prices have been raised for the industry to match the prices of import.

Figure 41: Middle East LRMC, LNG import, and subsidised prices (2020)



Source: Table 14 and Figure 39.

8.3 Netback from exports

LNG netback values have been evaluated through calculating the net gain value as the difference between the average incremental revenue from gas sold at the European market price of 5 USD/MMBtu, and average incremental LNG cycle costs (Liquefaction, shipping and regasification). These average incremental values are derived as the ratio of the net present value of the flows of LNG cycle costs or revenue from LNG trading, and shipped gas at an assumed weighted average cost of capital of 10%. The variation of gas prices are a function of the market of destination and in time affects the net gain of exporting gas as an alternative solution to employing it domestically to satisfy energy demand. From this stand point, these values may also represent the opportunity costs for domestic gas markets and as such be interpreted as benchmarks for countries' internal gas pricing.

8.4 Sector specific approach – Power

Estimating the netback value of gas at the power plant depends on both technical and economic aspects of gas, coal, and oil fired power plants. In this section we present the assumptions driving the netbacks of gas in the power sector.

The value of gas in terms of price to be assigned as an alternative means of energy generation in the domestic market, is calculated by equating the production costs of a new CCGT and a new coal or HFO fuelled power plants. This implies that the gas price will dependent upon:

- unit fuel price of the substituted fuel
- unit capital and O&M costs of the comparing plants

The aim is to find the maximum gas price which a power producer would be willing to pay compared to the alternative options available (HFO/LFO (new and existing) and coal)

In the case of existing HFO/LFO plants, capital costs will be assumed as "sunk". Consequently, the value of gas for CCGT plant derived from the production cost will be lower than under the hypothesis of new HFO/LFO plants characterised by "non-sunk" costs.

The following assumptions are valid for a new HFO/Diesel/LFO plant:

	Unit	New HFO/LFO/Diesel plant	New coal plant	New CCGT
Load factor	%	75%	75%	75%
Lifetime	Years	30	30	30
Power Capacity	MW	500	500	369
CAPEX	MUSD	995	1191	547
Unit capital costs	USc/kWh	5.5	6.6	4.1
O&M	USc/kWh	1.54	1.78	1.43
Fuel costs	USc/kWh	7.3	3.0	7.9*

*The input price of gas which makes generation costs (unit capital costs + O&M + Fuel costs) of a CCGT equal to the generation costs of a new HFO plant.

The efficiency is reflected in generation costs which account for not only capital and operational expenditures, but also the quantity of fuel necessary to generate the expected energy production which is related to thermal efficiency of energy generation cycle process.

In general terms, power plants' efficiencies depend upon the following characteristics:

- Power plant energy generation cycle (e.g. OCGT, CCGT, STPP)
- Heat exchange temperature (e.g. ambient exchange temperature)
- Power plant life time (aging effects)

Under the assumptions:

- that economic price for oil products and coal (i.e. price of fuel to be substituted) does not vary over time,
- uniform capital and operational costs in the geographical area of the MENA countries,
- and fixed transportation tariff of gas to power plants,

The net back value of gas primarily depends on efficiencies of newly built CCGT or converted existing power plants, and efficiencies of the compared Coal/Oil products fuelled power plants.

In the assessment the following country specific efficiencies have been assumed based on CESI's knowledge of the electrical systems in the MENA countries. Given the expected increasing energy demand over time and the lower capital costs leveraging of the economy of scale, it is reasonable to assume that power plants offering maximum power capacity would only be built up in the MENA region in case of necessity.

Consequently, in the calculation of netback values for gas, CCGT and OCGT, coal and HFO/LFO power plants featuring the maximum efficiency plants have been selected out among the suite of power plants utilised at the years of interest.

As observed in the below table, the majority of the countries presents constant efficiency values along the years illustrating how maximum power capacity will most likely still be featuring the same type of plant technology operating in 2020. Yet, with an increase of efficiency from 43% to 54%, Egypt represents the exception. This behaviour may be supported by the assumption that in this country, given the increasing energy demand and consequent growing power outages, newer CCGT plants might be expected to run by 2025. As a consequence, the net back value of using gas in power production will increase by 2025 in Egypt.

Table 17: Efficiency values for power plants over time

	COALPower Plant			**CCGT**			**OCGT Natural Gas**			**HFO STPP**		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**	2020	2025	2030	**2020**	**2025**	**2030**
DZ				45%	48%	48%	34%	34%	34%			
BH				48%	48%	48%	32%	32%	32%			
EG				43%	54%	54%	38%	38%	38%	41%	41%	41%
IR	26%	26%	26%	54%	54%	54%	27%	27%	27%			
IQ				48%	48%	48%	38%	38%	38%	38%	38%	38%
JO				40%	40%	40%	21%	21%		32%	32%	
KW				47%	47%	47%	28%	28%	28%	37%	37%	38%
LB					48%	48%	32%	34%	34%	37%	37%	37%
LY				43%	43%	43%	32%	32%	32%	42%	42%	42%
MA	40%	40%	40%	48%	48%	48%			34%	31%	32%	32%
OM				49%	49%	49%	32%	32%	34%			
PS					42%	42%						
QA				48%	48%	48%	32%	32%	32%			
SA				48%	48%	48%	47%	47%	47%	36%	36%	36%
SD	38%	38%	38%					32%	32%	32%	32%	32%
SY	40%	40%	40%				31%	31%	31%	30%	30%	30%
TN		37%	37%	44%	44%	47%	33%	36%	36%			
AE				48%	48%	48%	38%	38%	38%			
YE							32%	32%	32%			

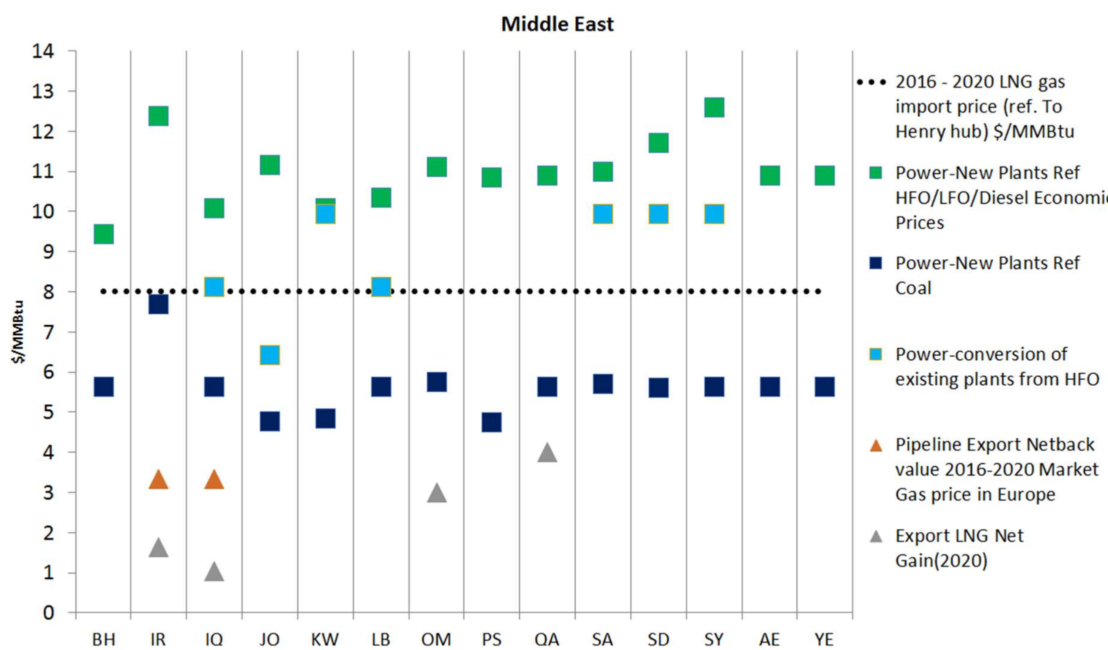
Source: CESI

8.5 **Trading space**

Gas can be monetized in several ways. However the fundamental question for this study is whether there is a trading space, defined as the area where both sellers and buyers are better off from trading, i.e. sellers receive higher netbacks than from exporting out of the region and buyers spend less on fuel than they would otherwise have done. This trading space is derived for each country, comparing the netback from export to world markets and the value of consuming gas in the power sector compared to using coal and HFO. The value of gas in the power sector is the value which makes the buyer indifferent between the competing fuel, taking into account capital costs, O&M, and efficiencies. Netback of gas for export has been divided into pipeline and LNG under the assumption that liquefaction costs are sunk for the facilities already constructed and up and running.

If the reference is construction of new HFO fired power plants (which we only consider as a solution to peak load problems) the case seems clear. The gas price could rise to levels of 10-11 USD/MMBTU and still be competitive with HFO. The variation between the countries originates from varying local efficiencies. The same conclusion is reached when comparing with existing HFO fired power plants, except in the case of Jordan, which have existing efficient HFO fired power plants. Comparing to coal is mostly relevant whenever new baseload is needed. It is seen that import prices or supply prices of gas above 6 USD/MMBTU would render the coal plant option more economic in terms of cost of generated electricity[10].

Figure 42: Netback value of gas in export (LNG+Pipeline), power sector (coal, HFO) ME



Source: Calculations

Figure 42 also plots the derived values of gas in the power sector against the netbacks of exporting gas out of the region. It shows that whenever the alternative is HFO (existing or new) for power generation, the value of gas, to the buyer, is always above the sellers' netback from export, leaving a positive trading space. If we consider coal as the reference the trading space narrows significantly for most countries. The figure also shows that if a country has gas it should seek to satisfy domestic demand in the power sector before thinking of exporting. This is the pattern that we see today in Oman where the government has decided that gas for export should be phased out by 2025 in favour of domestic consumption. The opposite example is Yemen

[10] The socio-economic costs in terms of emissions and health effects are obviously not taken into account in this calculation.

where domestic resources are being exported although the benefit to the local population would have been significantly higher.

A number of bilateral projects and possibilities appear from If the reference is construction of new HFO fired power plants (which we only consider as a solution to peak load problems) the case seems clear. The gas price could rise to levels of 10-11 USD/MMBTU and still be competitive with HFO. The variation between the countries originates from varying local efficiencies. The same conclusion is reached when comparing with existing HFO fired power plants, except in the case of Jordan, which have existing efficient HFO fired power plants. A number of cross border projects appear to have potential based on the value of gas and availability:

- Iran and practicality all their neighbour countries. Netback from exports is not very high – more value could be extracted by trading with the neighbouring countries in need of gas. In addition engaging in regional/local trade will be less risky than constructing large scale export infrastructure projects to reach world markets.
- Iraq too will have a relatively low value from exports to world markets. The priority here should be to satisfy own demand either by trading with its neighbours (such as Iran) or by increasing production capacity. This may take a long time.
- Qatar-Bahrain.
- Qatar – Saudi Arabia. A high value of gas in Saudi Arabia for both converting and establishing new power plants based on gas exist, combined with a netback of 4 USD/MMBTU it should be possible to work out a mutually beneficial agreement where both parties win.

Below in Table 18 the value of gas is compared against transport tariffs and the net gain of LNG export from Qatar. This quantifies the potential trading space which is large enough for both parties to gain from trade.

Table 18: Combinations of value of gas, tariffs, and alternative monetization from export Qatar.

Gas export from Qatar (via 42''onshore and 36'' offshore pipelines)					
Importers	Distance [Km]	Transport Tariff [USD/MMBtu]	Value of gas in power sector [USD/MMBtu]	Netgain from LNG export Qatar (2020)	Potential trading space [USD/MMBtu]
Oman	550	0,31	11,11	4	6,80
United Arab Emirates	180	0,06	10,89	4	6,83
Kuwait	832	0,49	10,09	4	5,59
Saudi Arabia	60	0,03	10,99	4	6,96
Egypt	2874	1,62	10,38	4	4,76
Bahrain	100	0,08	9,45	4	5,37
Iraq	950	0,55	10,08	4	5,52

The same exercise is done for Iran, (illustrated below in Table 19 showing that the net gain of trade with the neighbouring countries is even higher as netbacks from LNG are low due to the greenfield nature of any new plants.

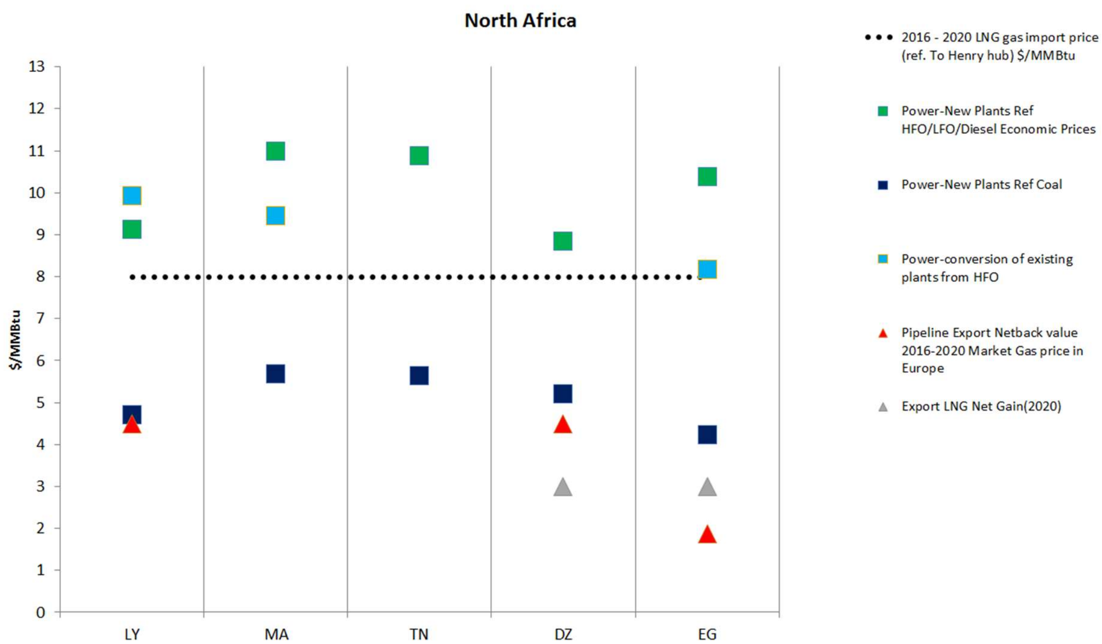
Table 19: Combinations of value of gas, tariffs, and alternative monetization from export Iran

Gas export from Iran (via 42''onshore and 36'' offshore pipelines)

Importers	Distance [Km]	Transport Tariff [USD/MMBtu]	Value of gas in power sector [USD/MMBtu]	Net gain from LNG exporter Iran (2020)	Netgain from pipeline export Iran (2020)	Potential trading space [USD/MMBtu]
Oman	550	0,31	11,11	1,65	3,33	7,47
Kuwait	750	0,43	10,09	1,65	3,33	6,32

It is the same picture for North Africa (illustrated below in Figure 43). Power plant conversion from oil carries a higher willingness to pay than from export outside the region.

Figure 43: Netback value of gas in export (LNG+Pipeline), power sector (coal, HFO)



Source: Calculations

The trading space identified give life to a number of bilateral projects such as:

- Morocco - Algeria, where the alternative to import of LNG is import of gas from Algeria. Algeria enjoys netbacks of around 3-4 USD/MMBTU – Morocco however should be willing to pay up to 6 USD/MMBTU, compared to the coal solution. Transportation costs between the two countries is minimal as pipelines already exist, assuming 0.25 USD/MMBTU. Distribution of the net gain should be a matter of negotiation between the countries – but remains a net gain for the region.
- The same could in principle be true in Tunisia where import from Libya could make sense given the high value of gas in Tunisia and the low netback from export for Libya.

9. INTERNATIONAL EXPERIENCE GAS INTEGRATION

9.1 Introduction

Gas projects are complex, involve billions of dollars of capital investments and are expected to operate for decades to secure gas supply and pay back upfront investments. Pipeline trade across borders adds to the complexity and increases risks. The more transit countries that are involved in a project the more the risk. These risks include political relationships among the countries involved; construction, security, price and market risks; determining which laws apply to the project that could otherwise affect the project; and agreement on common standards (technical, HSE). There are also question such as do any international or regional treaties apply? Are the legal systems of the participating countries stable and predictable? What provisions have the parties made for the resolution of disputes?

These risks can be mitigated in various ways, either through project-specific cross-border agreements between governments, or gas sales and purchase contracts that align the parties economic and financial interests, have fair prices for both buyers and sellers and are balanced throughout the project period. Other mitigation instruments are agreements with transit countries and international treaties, such as the Energy Charter, and supra-national structures, such as the EU or the US federal government.

In this chapter, we discuss how countries in the MENA region and in other parts of the world have negotiated and signed cross-border and transit agreements and provide examples such as the Maghreb-Europe Gas (GME) Pipeline from Algeria to Spain via Morocco, the Dolphin Gas Pipeline from Qatar to UAE and Oman, and the Bolivia-Brazil gas pipeline. We also examine the various Energy Charters and the areas of mitigation for international gas projects they support, how the EU internal market for gas promotes cross-border trade, and finally, lessons learned for the MENA region are drawn up.

9.2 Cross-border Gas Trade[11]

International gas pipelines involve one or more long-term contracts between private or state-owned companies on both sides of the border, with the border typically constituting the delivery point. It is quite common for the states involved to conclude a bilateral treaty or protocol, although important projects have succeeded in the absence of such agreements; for example, the Brazil–Bolivia gas pipeline. In such cases the commercial agreements between the participating companies may be subject to approval by governments.

The difference between internal gas trade within a country and trade across the border is the absence of a single overarching jurisdiction so the cross-border pipeline must operate in different legal and regulatory regimes when the border is crossed. Contracts must be drawn that establish rights and responsibilities from within potentially different legal regimes. In the presence of two independent sovereign jurisdictions there is no obvious mechanism for conflict resolution. International arbitration offers a solution to this problem, but recourse to such arbitration must be agreed and adhered to.

Importers become vulnerable to the possibility of gas supplies interruptions (technical or political), and exporters to the denial of their markets. Cross-border sales arrangements that do not involve a transit country have a relatively straightforward balance of interest, provided the gas is market-priced. In theory, interruptions cause similar damage on both sides of the border, and that damage is equal to the value of the gas. Neighbouring countries often have a record of hostility, for example, and this has affected pipelines in the past (e.g., Ukraine), or exporting countries change policies when gas consumption increase more than projected, resulting in

[11] ESMAP: Cross-Border Oil and Gas Pipelines: Problems and Prospects, 2003.

declining gas reserves, and they begin relocating export gas to the domestic market (e.g., Egypt, Algeria).

The acceptance of international norms through international agreements, such as GATT, WTO and the Energy Charter Treaty (see next section) can also limit the negative impacts of differing jurisdictions. Efficient and competitive gas markets additionally can minimize the consequences of legal differences.

The nature of the gas market and the level of development of the markets may differ greatly between the two countries connected by a pipeline. This would be the case for pipeline exports to Europe from MENA countries that have a more competitive gas market and a market price for gas. In most MENA countries, buyers are few, often state-owned companies. Thus the gas price must be negotiated by contract, frequently linked into oil or gas hub prices.

Successful international gas pipeline projects are projects where the economic interests are aligned between the exporting and the importing country, and they both have credible alternatives that set the benchmarks for the prices in the gas sales and purchase agreements, resulting in a balanced agreement that can stand the test of time.

9.3 **Transit**

If a pipeline transits third party countries then the risks and challenges increase further. Transit trade faces the problems of any cross-border trade, but the problems outlined above are compounded through increasing the number of parties engaged in a project.

In this case, the balance of interest changes as the transit country can cause damage to the project's operation and financial viability. The interests of a country that does not lift gas for its own use from the pipeline are fundamentally different from those of an exporting or importing country. Exporting and importing countries have more to lose by spoiling a deal than does a transit country. Transit countries only stand to lose their transit revenue when actively interfering with a deal, although such behaviour may also damage their international standing if they unilaterally interfere with bilateral or multilateral agreements.

In the case of Algeria's gas export, the ownership of the gas is transferred at the border of Tunisia and Morocco to importers in Italy, and Spain and Portugal respectively. The transit of the gas through Morocco and Tunisia is arranged by the importing countries from Europe (see Appendix 1).

As with other projects with heavy up-front, sunk investment without alternative use outside of the project, the balance of bargaining power among the parties can shift greatly as soon as the costs of the project become "sunk costs" and the situation balanced at the outset becomes obsolete, a phenomenon known as "obsolescent bargaining." Once there is investment then investors may be vulnerable to pressure from customers who are able to make credible threats to change suppliers and by other partners, such as transit countries[12].

Measures to minimize exposure to the problems associated with obsolescent bargaining are essential. Such measures must include credible threats to counter the temptation that might otherwise lead one party to unilaterally change the terms of an agreement.

Transit agreements involve a transit fee and there are several ways to approach the reasoning behind and the calculation of the transit fee:

[12] Cross-Border Oil and Gas Pipeline Projects: Analysis and Case Studies, the World Bank, review version, 5 September 2001.

The transit fee can be[13]:

- a form of compensation for the state surrendering part of its sovereignty;
- compensation for land use and taxes (this was the case for Morocco, see Appendix 1);
- a reward for helping to realize the value added (economic and political) in a cross-border gas trade (The Dolphin gas pipeline may fall into this category, see Appendix 1).
- an international norm that use charges per volume per kilometre (This is the case in Russia).

Case Study: The Maghreb-Europe Gas Pipeline from Algeria to Spain via Morocco[14][15]
The Maghreb–Europe Natural Gas Pipeline Project (Gazoduc Maghreb Europe; GME) involved the construction and operation of a 1,620km pipeline system to bring gas from the Hassi R'Mel field in Algeria, across Morocco and the Strait of Gibraltar, to interconnect with the gas grids of Spain and Portugal and into the rest of the western European gas transport system. The pipeline's capacity of 8 bcm/y was expanded later. The cost for the initial scheme of the GME was USUSD2.2 billion. GME is made up of seven sections (see Table 1).

Structure of the GME pipeline

Table 20: Structure of the GME pipeline

From	*To*	*Length (km)*	*Diameter (inches/mm)*	*Owner/Operator (% stake)*
Hassi R'Mel	Algerian/Moroccan border	518	48/1,219	Sonatrach
Morocco	Cap Spartel (Moroccan coast)	522	48/1,219	EMPL/Metragaz
Strait of Gibraltar	Split between Morocco and Spain	35	2 x 22/559	EMPL/Metragaz
Spanish coast	Cordoba, Spain	269	48/1,219	Enagas (67%) Transgas (33%)
Cordoba	Badalajoz (Spanish/Portuguese border)	269	28/711	Enagas (51%), Transgas (49%)
Campo Mairo (secondary section)	Braga, Portugal	408	28/711	Transgas (88%), Enagas (12%)
Braga (secondary section)	Tuy (Portuguese/Spanish border)	74	28/711	Transgas (51%), Enagas (49%)

In 1992, Sonatrach (Algeria) and Enagas (Spain) concluded a natural gas sale agreement for the delivery of a plateau level of 6 bcm/y through to 2020. In 1994, Sonatrach and Transgas (Portugal) signed an agreement for the delivery of a plateau level of 2.5 bcm/y of Algerian gas over a period of 25 years, beginning in 1997. The GME began to supply gas to Spain in November 1996 and to Portugal in January 1997.

Before the GME was developed, Algeria and Spain had already enjoyed two decades of LNG trade with each other and with other countries, demonstrating the economic viability of gas transport between the two countries and that provided a good benchmark against which to compare the economics of the gas pipeline. The pre-existing alternative of LNG also provided sound protection against exaggerated claims for transit fees.

The European Investment Bank (EIB) found the GME project attractive because it supported the EU's policies of increasing and diversifying energy supplies and of encouraging the use of clean

[13] ESMAP: Cross-Border Oil and Gas Pipelines: Problems and Prospects, 2003.

[14] Cross-Border Oil and Gas Pipeline Projects: Analysis and Case Studies, the World Bank, review version, 5 September 2001.

[15] ESMAP: Cross-Border Oil and Gas Pipelines: Problems and Prospects, 2003.

natural gas by industry and households. Ultimately, the EIB provided more than 1.1 billion euros for various sections of the GME. The GME project was announced in April 1991 following a meeting in Madrid of the energy ministers of Algeria, Portugal, and Spain.

A Tripartite Ministerial Monitoring Committee was set up to oversee the implementation of the project. Enagas SA (Spain) and SNPP (Morocco) were designated as the companies that would implement the project.

The Moroccan government authorized Enagas to build, use and operate the pipeline within the corporate structure specified by the agreement. Morocco was to receive "royalty gas," defined as 7 percent of the gas actually transported, as payment of the transit fee. The transit fee in turn was defined as representing compensation for the tax exemption offered to the project by Morocco and for the use of the land over which the pipeline ran. Under the agreement, Morocco can choose on relatively short notice to receive its royalty in gas or cash.

To finance the pipeline in Morocco and in the Moroccan portion of the Strait of Gibraltar, Enagas (9 per cent) and the Spanish government (91 per cent) in 1992 created a new company, Sagane SA, which in turn established Europe Maghreb Pipeline Ltd (EMPL). In 1994, Transgas of Portugal acquired 27.4 per cent of EMPL. Construction and operation of the pipeline was handled by Metragaz, which is owned jointly by EMPL and SNPP.

SNPP holds legal title to the gas pipeline in Morocco and the Algerian gas transferred title to SNPP at the Algerian – Moroccan border. That part of the GME that lies under the Strait of Gibraltar has its own corporate structure. In Moroccan waters the ownership structure is the same as that of the Moroccan land segment. Domestic Spanish law governs the segment of the GME lying in Spanish waters.

The gas sales agreement is structured as a long-term take-or-pay contract, and the agreement includes a firm minimum payment provision and pegs the gas price to the price of displaced fuels (fuel basket and basket of crudes).

Risk Mitigation

Enagas was privatized in 1994, and the Spanish government honoured its commitments to the GME pipeline project through a series of steps. To insulate Enagas from the specific risks posed in the initial phase of the project, particularly those related to technical risks during the start-up period, another state-owned Institute (NHI) remained engaged in the project, assuming a 91 per cent share in Sagane.

The implementation of the EU gas directive of August 10, 1998 carried some regulatory risk, to the extent that it could widen the choices available to gas consumers in Spain and Portugal, thereby causing Enagas and Transgas to lose market share and threatening their ability to fulfil the minimum payment provisions of their contracts.

The risk of non-performance is mitigated by a price review clause in the gas sales agreement that allows the commercial balance of the contract to be adjusted by the parties according to agreed rules. In case of disagreement the contract provides for resolution by a third party. Combined with the contract's enforcement clauses and a conflict resolution clause that provides for international arbitration, the risk of unilateral abrogation of the sales agreement appears to be small. Any threat by Morocco to renegotiate the transit agreement seems limited, because Morocco's fee depends on throughput and because the parties to the gas sales agreement have proven alternatives, at least in the long term, to transit through Morocco.

Sonatrach, Enagas, Transgas, and Morocco would share the impacts of reduced production. Any interruption of Sonatrach's production in Algeria would be shared by the parties involved:

Morocco would lose transit revenues, Sonatrach would lose gas sale revenues, and Enagas and Transgas would lose gas supplies and thereby their margins on any gas that they could otherwise have sold to customers and that they were unable to replace from other sources. Although the minimum payment provision would not protect Sonatrach against a complete collapse of the market, it does give the company protection against efforts by its customers to optimize their purchases. Because the minimum pay volumes have to be paid for whether or not they are taken, taking gas from other suppliers before fulfilling the minimum payment provision would be suboptimal regardless of the other suppliers' prices.

Sonatrach assumed the construction cost and cost overrun risks for the Algerian section of the GME. Enagas and Transgas were responsible for the construction of the Moroccan, Spanish, and Portuguese sections and for the section at the Strait of Gibraltar. During the construction period, Sagane, which was created by the Spanish public sector for this purpose, assumed the risks associated with construction of the Moroccan section. If any part of the GME pipeline is prevented from operating by reasons of force majeure, all parties share the risk, as each would lose the income linked to the missing throughput capacity.

Case Study: Dolphin Gas Pipeline[16]

Qatar was the force behind the creation of the Dolphin Project a much reduced form of the pan-GCC pipeline, envisioned at the November 1989 GCC summit meeting as the most ambitious domestic Middle Eastern gas project ever undertaken. As originally conceived, a transnational pipeline was to connect the national gas grids of Saudi Arabia, Kuwait, Bahrain, and the UAE into a single integrated system and extensions to Pakistan and other countries were envisioned.

UAE Offsets Group (a branch of the UEA Ministry of Defense) agreed in 1998 that Qatar would serve as the exclusive supplier and marketer of Qatari gas in the UAE and Oman. With QP as the negotiating partner, the Offsets Group completed initial MOUs with Qatar, Oman, and Pakistan, in June 1999. Dolphin Energy Limited was created in 1999 to manage the project. Its ownership structure is shown in Table 21 Mubadala Development Company which is a wholly-owned subsidiary of the Abu Dhabi government gas owns the majority in the company.

Table 21: Ownership of Dolphin Energy Limited

Company	*Constituents*
Mubadala Development Company 51%	Wholly-owned subsidiary of the Abu Dhabi government
Total 24.5%	
Occidental Petroleum 24.5%	

While much of the impetus behind Dolphin was to improve political integration of the GCC nations, the project also had its bedrock commercial aspects. Oman and the UAE (Dubai and Abu Dhabi) faced a significant gas shortage that would be unlikely to be satisfied, even with increased imports from Qatar.

The UAE supplies gas to the domestic market at USD0.75/MMBTU. Artificially low domestic prices mean that it is more attractive for the UAE to import gas through Dolphin rather than develop its own gas. It is not feasible for the UAE to increase indigenous gas production with subsidized domestic gas prices. The fact that neither the IOCs nor ADNOC view the development of domestic sour gas reserves as profitable lends more weight to the case for domestic gas price increases. Exporting gas at prices below the international level, Qatar incurs a significant opportunity cost which indirectly cross-subsidizes the UAE's industrialization.

[16] OIES: The Dolphin Project: The Development of a Gulf Gas Initiative Justin Darin 2008

The cost of the proposed processing plant and pipeline was estimated USD3.5 billion: USD2.5 billion for the construction costs of the processing plant in the Ras Laffan industrial city, and USD1 billion for the pipeline.

In 1999, Mobil Oil and Qatar signed an MOU with UAE Offsets Group as a prelude to a long-term supply and purchase agreement that would allow UAE Offsets Group to obtain gas and condensate by-products from existing concessions, and an option for gas from Mobil Oil Qatar�much Enhanced Gas Utilization Project. A statement of principle signed between QP and UAE Offsets Group allowed Dolphin Energy to obtain its own concession from two blocks in the North Field over the project�much term. Dolphin successfully negotiated a 25-year development and production sharing agreement with QP in 2001. Starting in June 2007, Dolphin began transporting 400 MMcf/d (3.9 bcm/y) of natural gas to the UAE and Oman, 2 bcf/d (20 bcm/y) in 2008, of which 200 mcfd (2 bcm/y) goes to Oman.

The term sheet sets out the mutual understanding of QP and Dolphin on certain commercial matters of the development and PSA. Although not legally binding, the term sheet provides later guidance to legal counsel of the final terms of the agreement. The QP/Dolphin term sheet covered the BTU value of the total volume of the produced gas, the take-or-pay clause, and the maximum/minimum volumes of gas to be lifted in accordance with seasonal demand. The take-or-pay rate was 85 per cent of the contracted volume.

QP and Dolphin failed to reach agreement on a sales price for North Field gas. The Emir of Qatar and the Abu Dhabi leadership intervened and concluded that commercial considerations could no longer delay the Dolphin pipeline. QP was unhappy with this highly political resolution because it considered both the FOB price of USD0.87mn/BTU ex-Ras Laffan, and the delivered CIF price of USD1.30/MMBTU was much too low.

After further high-level intergovernmental negotiations between the UAE and Qatar, the parties reduced the annual price escalation to 1.5 %. The negotiators mollified Qatar with ownership of the extra volumes of the revenue-rich and highly valuable condensate stripped from the gas at the Ras Laffan processing plant. While the pricing negotiations between the Dolphin Pipeline and Dubai began contentiously, the parties agreed that Dolphin pipeline would sell gas to Dubai at USD1.30/MMBTU (CIF Al-Taweelah) and add transport costs for gas from Al-Taweelah to end users in Dubai.

Even though the Dolphin Pipeline realistically argued that it could not provide gas to Dubai at less than USD1.30/MMBTU, Dubai pointed out that gas from Abu Dhabi cost only USD1.00/MMBTU through the Al-Taweelah/Jubal Ali pipeline. Dubai suggested that Dolphin‛s other customers, specifically Abu Dhabi and Oman, be required to subsidize the cost differential. Dolphin committed itself to deliver gas at the price it obtained from Qatar, and to add a transportation tariff for the customers in the UAE and Oman, resulting in a price of USD1.30– 1.40/MMBTU.

In its early stages, Dolphin had difficulty in securing outside financing. Many IOCs were initially alarmed at the absence of a sovereign guarantee. Many in the project finance sector also thought that a large undertaking such as Dolphin should have a state-backed loan guarantee. Because of the difficulty in locating appropriate funding, the equity partners assumed responsibility of funding the project‛s early expenditures.

Dolphin‛s partners, who wanted a better rate on equity holdings, knew that financing difficulties would plague Dolphin until the project fundamentals were in place. To facilitate funding, Dolphin entered into a USD2.45 billion bridge loan in 2004 with a consortium of 20 local regional and international banks, which structured the bridge loan as a classic multi-tranche deal with non-recourse project financing, covering construction costs up to the completion date.

A unique feature of the Dolphin Project was the fact that Dolphin relied on Islamic financing. In 2005, Dolphin entered into an Islamic financing agreement with fourteen financial institutions to provide USD1 billion to fund a part of the construction. The four-year financing facility was structured as an Istisna'a transaction in which Dolphin enters into an agreement to construct the portion of the project relating to the transportation system on behalf of the Islamic investors, and enters into a Forward Lease Agreement for the use of such assets[17].

On October 5, 2016, QP and Dolphin Energy signed - in the framework of friendlyrelations and cooperation - an agreement for additional gas deliveries to UAE. After upgrading processing facilities at the processing plant in Ras Laffan in 2015, the capacity of the pipeline now reaches 3.2 bcf/day (32 bcm/y)[18]. The price and volume was not made public.

Case study Bolivia-Brazil pipeline19
In 1990, the governments of Bolivia and Brazil decided to (re)examine a gas pipeline export project from Bolivia to Brazil. The share of natural gas in Brazil's energy matrix was still only about 3 per cent. Brazil however, was forecasting strong growth in energy demand. Natural gas had the potential to offset an increasing dependence on more expensive fuels such as LPG.

The motives on the Bolivian side were primarily economic. Bolivia had been exporting gas by pipeline to Argentina since the 1970s, but new discoveries in Argentina meant that the arrangement was no longer tenable. Because sales to Argentina accounted for some 80 per cent of Bolivia's total gas production, it was critical to find an alternative market to sustain the country's export earnings.

In 1993, the two state monopolies, Petrobras and Yacimentos Petroliferos y Fiscales Bolivianos (YPFB), signed a 20-year gas sales agreement for an initial supply of 8 million cubic meters per day (MCM/d) of natural gas. The amount would increase linearly over the first eight years of the contract to a plateau level of 16Mcm/d.

The challenge was how to attract private financing for a 2 billion USD project linking two countries with traditions of noneconomic fuel-pricing policies and non-transparent government regulation.

In November 1995, a constitutional amendment removed the constitutional barriers to private sector participation in oil and gas activities, thereby effectively ending Petrobras' monopoly. Other obstacles to the development of a gas market with private participation still remained, however. The most important of these was government control over fuel prices.

The private partners soon began to signal to the Brazilian government that realization of the project would require fair access to downstream markets and market-based pricing policies consistent with those recommended earlier by the World Bank for encouraging development of the country's hydrocarbon industry. Such policies were included in the hydrocarbon law approved by Brazil's Congress in August 1997.

Following a roadshow, Petrobras selected a consortium of British Gas, Tenneco (later El Paso Energy), and BHP. The consortium, known as BTB, formed Transportadora Brasileira Gasoduto Bolívia- Brasil, SA (TBG), to assume ownership of the Brazilian part of the pipeline. Fifty-one per cent of TBG's stock was held by Petrobras.

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[17] http://www.dolphinenergy.com/

[18] http://www.dolphinenergy.com/

[19] Private sector note no 144 International Gas Trade— The Bolivia-Brazil Gas Pipeline. World Bank. ESMAP: ibid.

Table 22: Ownership structure of the Bolivian and Brazilian transport companies

Company	*Constituents*
Bolivian Gas Transport Company (*Gas Trans-Boliviano*, GTB)	
Bolt JV: 85 percent	Shell/Enron: 40 percent Transredes (a 50/50 partnership of Shell/Enron and Bolivian Pension Funds): 60 percent
BTB: 6 percent	BHP: 33.3 percent El Paso Energy: 33.3 percent British Gas: 33.3 percent
GasPetro: 9 percent	Petrobras: 100 percent
Brazilian Gas Transport Company (*Transportadora Brasileira Gasoduto Bolivia Brasil*, TBG)	
GasPetro: 51 percent	Petrobras: 100 percent
BTB: 25 percent	BHP: 33.3 percent El Paso Energy: 33.3 percent British Gas: 33.3 percent
Shell/Enron/Transredes: 20 percent	
Private investors: 4 percent	

On the Bolivian side, a partnership agreement was reached between Enron and YPFB that included development of the Bolivian section of the pipeline. At the time, YPFB was being prepared for capitalization and sale by international tender. Legislation passed in 1996 committed Bolivian reserves to the export project and defined a diminished role for YPBF as the aggregator and shipper of future gas exports to Brazil. Shortly thereafter YPFB was split into two private exploration and production companies and one oil and gas transportation company. The Bolivian transportation company Gas Trans-Boliviano SA (GTB) was formed for the gas export project as a private joint venture among Enron, Shell, and Bolivian pension funds.

The ownership structure of the Bolivian and Brazilian transport companies is shown in Table 3. The Bolivian side of the project structure is essentially private. On the Brazilian side, majority ownership (51 per cent) resided with GasPetro, a wholly owned subsidiary of Petrobras. The structure nevertheless allows a degree of cross-border ownership by each group.

During the project development phase, technical, environmental and financial committees were formed with representation from all of the sponsor groups to resolve issues and ensure the cross-border harmonization of the project. This feature was to prove beneficial in enabling smooth coordination of the project.

The project required a large upfront investment with a gradual build-up of tariff revenues and a final gas price that would provide incentives for a speedy uptake of gas by industrial users and eventually power plants. Equally daunting was the fact that of the five Brazilian states through which the pipeline would pass only one, Sao Paulo, had a gas distribution network that could accept Bolivian gas. The distribution systems in the other states would have to be developed from scratch. Commercial lenders also perceived some supply risks, since Bolivia’s proven and probable reserves of approximately 200 billion cubic meters could meet only 80 per cent of the gas sales contract.

No private long-term financing was forthcoming and in 1997 the World Bank decided to appraise the project. World Bank analysis showed the project to be economically viable and the best of several alternatives. The final route for the pipeline was selected to minimize its environmental impact, and the project included full measures to protect the interests of indigenous people living near the pipeline. On the Brazilian side, multilateral lending and partial credit guarantees offered the prospect of longer loan maturities and an appropriate gas price for penetrating the market. On the Bolivian side, only 20 per cent of the necessary financing was available in the form of shareholder equity and the Bolivian government was unprepared to provide sovereign guarantees for multi-lateral financing.

Petrobras responded with two mechanisms. Firstly, it agreed to arrange financing for a fixed-price, turnkey construction contract for the Bolivian section of the pipeline, with repayment through the waiver of future transportation fees on the Bolivian side; this financing was arranged through Exim (see Table 23) Secondly, Petrobras agreed, at its own risk, to pre- purchase 6 Mcm/d of the uncommitted upside capacity of the pipeline on both sides of the border.

Table 23: Funding for the Bolivia-Brazil Gas Pipeline, (MUSD)

Funding source	*GTB (Bolivia)*	*TBG (Brazil)*
Shareholder equity (including subordinated loans)	75	310
Petrobras transport capacity option, with Brazilian National Development Bank and Andean Development Corporation financing	81	302
Petrobras loan, with Jexim/Marubeni and Brazilian National Development Bank financing		348
Petrobras advance payment contract, with Jexim/Marubeni financing	280	
World Bank loan		130
World Bank partial credit guarantee		180
Inter-American Development Bank		240
Corporación Andina de Fomento		80
European Investment Bank		60
Total	**436**	**1,650**

Petrobras and YPFB were signatories to the sales contract for 16Mcm/d of gas. YPFB collects the gas from the producers and transports it to the border under a ship-or-pay transportation contract between YPFB and GTB. Petrobras takes ownership of the gas at the border and has a ship-or-pay transport contract with TBG. Petrobras has back-to-back take-or-pay contracts with the gas distribution companies in the five states traversed by the pipeline. The contract was expanded in 2006, and Brazil currently imports a minimum of 24mn m3/d (8.7 bcm/y) and a maximum of 30.08mn m3/d (11 bcm/y) from Bolivia. The current price is around USD4/MMBTU.

Petrobras agreed to take the TCQ and transport capacity option very early in the project development phase. To commit to full capacity represented a substantial risk for Petrobras, which ultimately was willing to bet that both the reserves in Bolivia and the market in Brazil could be developed sufficiently to use the full capacity of the pipeline.

Under arbitration by the new federal hydrocarbon regulatory agency, the Agencia Nacional do Petroleo (ANP), third parties negotiated with TBG to utilize the available capacity that exists in the short term.

Risk and risk mitigation

Petrobras bears most of the risk on both sides of the border. Although the gas supply risk on the Bolivian side falls on YPFB, this risk is considered small because of the likelihood of additional supply becoming available from new discoveries. Nonetheless, if YPFB fails to deliver the contractual volumes of gas, Petrobras will be entitled to claim financial compensation from YPFB.

The most serious risk was considered to be the market risk in Brazil. Four of the five distribution companies involved in the project were paper companies only, with no pipes in the ground. Gas would have to penetrate a market dominated by subsidized, low-priced, high-sulphur fuel oil. To mitigate the price risk, the gas distribution companies reached a collective agreement with Petrobras that the city-gate price of Bolivian gas delivered to the distribution companies would be set equal to 85 per cent of the local price of high-sulphur fuel oil for the first five years of pipeline operation, an arrangement that would help ensure that natural gas could compete in the market until full deregulation of fuel prices. After five years, the commodity price would be set on a pass-through basis using the price-indexing formula in the gas supply agreement between YPFB and Petrobras.

Through its subsidiary, BR Distribudora, Petrobras took a minority equity stake in several of the local gas distribution companies, with the notable exception of the state of Sao Paulo.

Through its turnkey construction contract, Petrobras bore the construction risk on the Bolivian side. Finally, if the pipeline in Brazil were not built on time, Petrobras would incur financial penalties payable to YPFB and the distribution companies.

Construction of the main trunk line to Sao Paulo was completed on schedule in December 1998, and the southern leg to Porto Alegre was finished in March 1999. Petrobras secured the full transport capacity in the belief that sufficient gas discoveries would be made in Bolivia and that the Brazilian gas market would develop sufficiently.

After the commencement of pipeline construction, Bolivia's proven and probable gas reserves increased fivefold. Subsequently, Bolivian gas reserves were developed by Petrobras' subsidiary in Bolivia, and by several private producers. However, production growth could have been hampered by the May 2006 nationalization of assets belonging to private firms which was a reversal of initiatives by previous administrations to privatize and weaken YPFB. After 2006, private firms could only enter into service contracts, production-sharing agreements and joint ventures with YPFB, and all oil and natural gas extracted had to be sold through YPFB. With the reforms, YPFB became the primary regulator in the energy sector, but it also dissuaded greater foreign investment in a country and slowed down investments in gas20.

Bolivia also exports about 15mn m3/d (5.5 bcm/y) of pipeline gas to Argentina under a 21-year agreement signed in 2006. The Bolivian and Brazilian parties began talks in 2015 to renegotiate the natural gas supply contract before it expires. At the same time, Petrobras is reducing non-core assets and has already finalized a deal to sell a 49 per cent interest in its gas distribution subsidiary Gaspetro to Japanese trading house Mitsui.

Case study West African Gas Pipeline

The preparations for the West African Gas Pipeline Project were impeccable (See also Box 8
).

- A Heads of Agreement between the four states was signed in 1995
- In 1999, they executed a MOU to select a private developer to build, own and operate the pipeline, West African Gas Pipeline Company, WAPCo

[20] Statfor: Bolivia's Natural Gas Sector Is Under Threat, August 18, 2015.

- In 2000, the four States executed an Intergovernmental Agreement establishing a harmonized investment regime for the Project
- In January 2003, the four states entered into the West African Gas Pipeline Treaty, which established the
  - WAGP Authority, which monitors compliance under the International Project Agreement, approves FEED and conceptual design of project, grants project authorizations, regulates tariffs, enforce Regulations governing the construction and operation of the Pipeline System
  - WAGP Tribunal for Conflict Resolution
  - Fiscal Review Board which has exclusive jurisdiction on review of decision or action or inaction of a State Party, a Tax Authority, any other State Authority or the WAGP Authority in relation to the application of the Agreed Fiscal Regime
- In May 2003, the four states entered into an International Project Agreement with WAPCo

Despite the excellent planning of the legal and regulatory framework for the pipeline, the project was unsuccessful due to the lack of gas supplies (see Case study Box 8). This questions whether the economic interests between the countries were fully aligned and whether the risk sharing mechanism was properly established.

Box 8: West African Gas Pipeline

Case study West African Gas Pipeline

West Africa Gas Pipeline (WAGP) is a regional project, comprising: (a) a new pipeline system (678 km long) transporting natural gas from Nigeria to Ghana, Togo, and Benin; (b) spurs to provide gas to power generating units in Ghana, Benin, and Togo; (c) conversion of existing power generating units to gas, and (d) investment in compressor stations. The peak capacity was planned 460 Million standard cubic feet per day (MMscf/d) but in the first phase, 170 MMscf/d was expected to be transported.

Project and Intergovernmental Agreements

A Heads of Agreement between the four states was signed in 1995, and in 1999 they executed a MOU to select a private developer to build, own and operate the pipeline, West African Gas Pipeline Company (WAPCo, see Table). In 2000, the four States executed an Intergovernmental Agreement establishing a harmonized investment regime for the Project, and in 2003 they entered into the West African Gas Pipeline Treaty, which most importantly established the WAGP Authority, the regulatory body for WAPCo, the WAGP Tribunal and the Fiscal Review Board. FID was taken in 2004.

Owners of WAPCo	Ownership %
Chevron Nigeria Limited	36.7%
Nigerian National Petroleum Corporation	25%
The Shell Petroleum Development Company of Nigeria Limited	18%
Ghana National Petroleum Corporation	16.3%
Societé Beninoise de Gaz S.A.	2%
Societé Togolaise de Gaz S.A	2%

N-Gas Limited (an entity owned by Chevron, Shell and NNPC) contracted for the purchase of gas from producers in Niger Delta, transportation over the ELPS pipeline in Nigeria, injection and transportation through WAGP, and sales to power utilities in Ghana, Benin and Togo. The first natural free flow gas supply through WAGP arrived in Ghana in December 2008. The Commercial Operation Date for the project was reached October 2011. Prior to this, natural gas was supplied to on a 'best-endeavor' basis, without 'take-or-pay' provisions being applied. The throughput reached 84 MMscf/d in 2011, much lower than expectations. Gas supplies were, however disrupted on account of pipeline rupture August 2012, and restored in June 2013.

Why was the project unsuccessful?

The sponsors (Chevron and Shell) were credible and the preparation process followed the textbook for intergovernmental agreements, treaties and even an authority regulating the pipeline in the four countries was established. However, several factors impacted the project in a negative way. WAPCo changed its management team after financial closure and brought in a new construction team, which caused delays. The pipeline was damaged by ships and a rupture. There were problems with resettlement compensations.

Most importantly, however, gas supply from Nigeria was faced with a number of issues. Absence of a modern legal framework for gas and low gas prices hindered the growth of domestic production resulting in Nigeria's power sector not receiving sufficient gas. At the same time around 20 bcm of associated gas was flared in Nigeria. Another constraining factor was that gas infrastructure development in Nigeria was slower than expected, in particular the ELPS pipeline transporting gas to WAGP. Vandalization of existing gas infrastructure by militants was another major cause of inadequate supplies.

9.4 The Energy Charter[21]

As for international treaties, the Energy Charter Treaty was conceived as a European initiative with a focus on 'East-West' cooperation. The scope of the Energy Charter however is now considerably broader. The Energy Charter goes further than the WTO framework in addressing specific challenges for the energy sector, such as provisions on the protection of investment. The Charter also covers in more detail the issue of energy transit, and includes a distinctive mechanism for the resolution of energy transit disputes.

Box 9: MENA and the Energy Charter[22]

The European Energy Charter is a political declaration adopted in the Hague in 1991. The European Energy Charter contained a commitment to negotiate in good faith a legally binding Energy Charter Treaty and Protocols.

All Charter signatories are Observers to the Energy Charter Conference, and signing is a first and necessary step towards accession to the 1994 Energy Charter Treaty.
Jordan, Morocco, Mauretania, Syria, and Yemen are signatories of the European Energy Charter (1991) and observers to the Energy Charter Conference.
Algeria, Bahrain, Egypt, Iran, Kuwait, Oman, Qatar, Saudi Arabia, and United Arab Emirates are observers to the Energy Charter Conference by invitation.

The Energy Charter Treaty is an instrument for the promotion of international cooperation in the energy sector. The Treaty, which entered into force in 1998, and its related documents, provide an important legal and political basis for the creation of an open international energy market. The countries that have ratified the treaty are fully bound by its provisions.
Jordan is approved for accession to the 1994 Energy Charter Treaty by the Energy Charter Conference.

The International Energy Charter is a further political declaration adopted and signed in the Hague in 2015. This more recent political declaration reflects global modern energy challenges and maps common principles and areas of international cooperation in the field of energy for the 21st Century. As a result of increased interest by the international community the Energy Charter Process has expanded to involve over 90 states from all continents.

The *Energy Charter Treaty* provides a multilateral framework for energy cooperation that is unique under international law. It is designed to promote energy security through the operation of more open and competitive energy markets, while respecting the principles of sustainable development and sovereignty over energy resources. It was signed in 1994 and entered into legal force in 1998. The Treaty's provisions focus on four broad areas:

- the protection of foreign investments, based on the extension of national treatment, or most-favored nation treatment (whichever is more favourable) and protection against key non-commercial risks;
- non-discriminatory conditions for trade in energy materials, products and energy-related equipment based on WTO rules, and provisions to ensure reliable cross-border energy transit flows through pipelines, grids and other means of transportation;
- the resolution of disputes between participating states, and - in the case of investments - between investors and host states;

[21] www.encharter.org

[22] www.encharter.org

- the promotion of energy efficiency, and attempts to minimize the environmental impact of energy production and use.

Once an energy investment is made, the Treaty is designed to provide a stable interface between the foreign investor and the host government. It is a major task to reduce these risks, as far as possible, by creating a stable and transparent investment climate. The Energy Charter Treaty assists by offering binding protection for foreign energy investors against key non-commercial risks, such as discriminatory treatment, direct or indirect expropriation, or breach of individual investment contracts.

A second priority for the Treaty is to promote reliable international transit flows.
Under the Treaty, member countries are under an obligation to facilitate and to establish pricing for transit of energy without discrimination as to the origin or destination of ownership and without imposing any unreasonable delays, restrictions, or charges. When transit is not feasible given the existing capacity, contracting parties shall not place any obstacle in the way of the new capacity being established.

If a member country feels that another state is not complying with its obligations under the Treaty - and if no resolution is possible through bilateral diplomatic channels - then the matter can be taken to binding international arbitration. This mechanism is applicable to almost all disputes arising under the Treaty, with the exception of the articles on competition and on the environment.

International Charter

The International Energy Charter is a declaration of political intention aiming at strengthening energy cooperation between the signatory states and which does not bear any legally binding obligation or financial commitment.

The original Charter helped former Soviet Republics attract investment and strengthen their domestic energy legislation during the 1990s and the International Charter has been extended to play a similar role in the MENA region, Asia and Africa. This would not entail any reform to the Energy Charter Treaty itself, but has created a new international political declaration, the International Charter, to attract new countries.

Supra-National structures - EU
The EU regulation of internal market for gas, which was developed in the late 1990’s to achieve lower prices by increased competition, is complex.

The EU opened up for competition in the gas market and to improve the functioning of the internal gas market, it introduced common rules for the transmission, distribution, supply and storage of natural gas as outlined in the Directive on Internal market in gas[23]. According to the Directive, transmission system operators must build sufficient cross-border capacity to integrate the European transmission infrastructure. Every yearthey must submit to the regulatory authority a ten-year network development plan indicating the main infrastructure that needs to be built or modernised as well as the investments to be executed over the next ten years.

In most MENA countries, gas is supplied by state-owned companies at government set prices and gas buyers are relatively few, and are also often also state-owned companies. As discussed elsewhere in the report, only a few pipeline connections exist between the countries. The regional economic cooperation organizations do not have the powers to intervene in how the gas markets

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[23] (2009/73/EC)

function, how prices are set, or to promote the construction of cross-border gas pipelines. The Supra-National structure instruments are not relevant at this point of time.

The beginning of International gas trade in Europe[24]

As in the MENA region, natural gas was discovered in Europe in several countries around the same time.. However it took decades to develop national gas networks and even longer before the first gas was traded over borders.

Natural gas was discovered in France 1939 and the large Lacq field in 1951, in Italy 1938, and in the Netherlands in 1948. The giant Groningen field was discovered in 1959. In the beginning gas was used in "premium markets", such as the replacement of manufactured gas, industries, and later residential use, rather than for power generation.

Gasunie was created in the Netherlands in 1963 to market and transport Dutch gas and introduced the "market-value" principle as the basis on which gas should be produced and sold. This meant that the price of gas was linked to the price of the alternative fuels for that customer. So consumers would never have to pay more (but also not less) for gas than for competing fuels.

The first LNG cargo arrived in the UK in 1959 and five years later LNG imports from Algeria started. In 1967, the UK started producing natural gas in the North Sea and a national grid was built.

Germany found small amounts of natural gas in the 1950s, but German natural gas consumption really took off after the discovery of the Groningen field in the Netherlands. Large volumes of gas were imported from the field, starting in the mid-1960s.

As the demand for natural gas in France, Italy and Germany started to outpace indigenous production, more gas imports were needed. An international network of high-pressure pipelines in Europe was constructed.

Demand continued to outstrip European gas production and gas imports by pipeline from outside Europe started with the USSR Brotherhood pipeline in 1967, connecting gas fields in Ukraine to Czechoslovakia and delivering gas to Western Europe., The Transgas pipeline was added in 1974. The first Norwegian deliveries from the Ekofisk field started in 1973 and in 1986, deliveries were made from the giant Troll field. In 1983, the Transmed pipeline came on stream connecting Algeria with Italy, followed the by GME in 1996 to Spain and Portugal.

Additional international connections followed: Denmark to Germany and France to Spain in 1993. The UK however was not connected to Continental Europe by pipeline until late 1990s ("the Interconnector").

Liberalization of the gas market

By the late 1980s, the European gas market was dominated by four large suppliers - the Netherlands, Norway, Algeria and the USSR as well, as four large gas companies importing gas and selling the major part of it in Germany, France, Italy and the UK. Gas was sold on the market value principle, and gas exports were based on long-term contracts to minimize risks and based on the netback principle – the price of gas in the destination country was linked to competing fuels, and the supplier received a border price based on this value minus transportation and distribution costs in the importing country.

[24] IEA: Development of Competitive Gas Trading in Continental Europe

This was not a competitive gas market. The US had deregulated its gas market and introduced gas-to-gas competition in the 1980s. The UK introduced third-party access to (British Gas') pipelines in 1986 to increase competition. Although the liberalization process was longer than anticipated and lasted until 1997, it resulted in more competition and in the restructuring of the UK gas industry. In Continental Europe there were successful attempts to bypass the traditional gas importers in Germany and in the Netherlands in the late 1980s.

One of the core objectives of the European Union was a single market for gas (and electricity) and the 1998 Gas Directive (98/30/EC) introduced the first set of common rules for the EU energy markets. For natural gas, the new legal framework was aimed at opening the gas networks to third parties (TPA). This was to be achieved through unbundling of the existing vertically integrated gas operators, thus allowing competition for supplies and customers within the natural monopoly network, (see Box XX). Initially, the opening to competition granted the choice of supplier to large gas customers, such as power plants and big industrial facilities. At least 20% of the national market had to be open for competition.

To ensure transparent and non-discriminatory access to all potential suppliers of the market, the infrastructure operator was to be unbundled, at a minimum on an accounting level. The monitoring of this new system was assigned to a regulatory body in each country, which had to be independent from the market and from the state, to ensure transparent and non-discriminatory operations on the market.

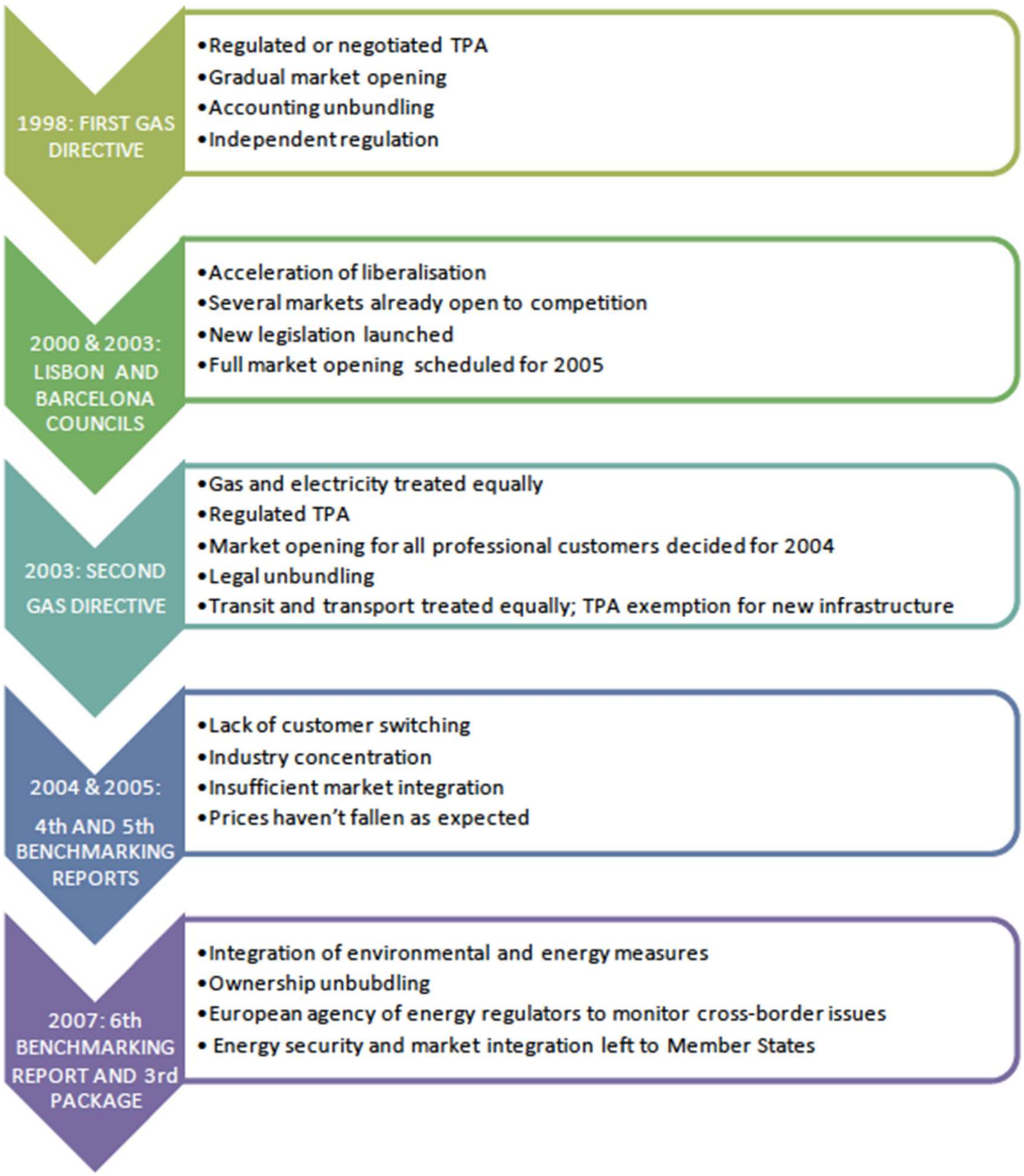
The liberation process was accelerated in 2000 and 2002. Several markets had opened more than the required consumption level (79% vs. the minimum of 20%) and the target for a full market opening was set to 2005. In 2003, the second Gas Directive was adopted[25] parallel with the Electricity Directive. The new EU gas law mandated regulated TPA as the basic rule (for all existing infrastructure) as well as moving the level of unbundling of Transmission System Operators to the level of legal separation (e.g. regulated activities under the responsibility of separate entities). The role of the independent regulators was also reinforced. The special status of "transit pipelines" as exempt from TPA rules was eliminated.

The results were not satisfactory as competition was slow to develop and a number of issue were still unresolved: Customer switching was not sufficient; in the absence of increased interconnection, new suppliers were not able to enter the markets, and gas could not circulate freely from one point to another, prices had not fallen as expected, and investment had become an issue, especially in cross-border interconnections.

The 2009 Directive on Internal market in gas[26] addressed several of these issues. From 2012, Member States had to unbundle transmission systems and transmission system operators. It required each Member State to designate a single National Regulatory Authority. Transmission system operators must build sufficient cross-border capacity to integrate the European transmission infrastructure. Every year, they shall submit to the regulatory authority a ten-year network development plan indicating the main infrastructure that needs to be built or modernized as well as the investments to be executed over the next ten years.

[25] (2003/55/EC)
[26] (2009/73/EC)

Figure 44: EU Moving towads a competitive gas market



Source: European Commission

The EU's vision for a single gas market includes the establishment of gas hubs in each market area as well as regional hubs at which it is intended all gas will be delivered for sale and purchase – whether under long-term contract or traded. Today, two hubs are leading as established benchmark hubs, the British NBP (National Balancing Point) and the Dutch TTF (Title Transfer Facility)[27].

[27] OIES: The evolution of European traded gas hubs, NG104, 2015.

10. COUNTRY AND HUB SUMMARIES

10.1 Algeria Hub

An Algerian gas hub will constitute Algeria, Morocco and Tunisia and will be closely linked to South Western Europe via pipelines to Spain and Italy and historical LNG supply agreements to France and Spain.

The dominant player in this hub is Algeria, which has huge gas reserves of more than 4500 bcm and has developed a large and integrated gas transmission system, with the giant Hassi R´Mel gas field as the hub. The system is now being extended to the south of the huge country – the largest in Africa. From the south it may also be possible to interlink the transmission system to Nigeria by creation of the Trans Saharan Gas Pipeline. Algeria can potentially also be connected to Libya. Morocco and Tunisia have benefitted by being transit countries from Algeria to Europe.

Algerian connection to the EU is very similar to the Norwegian situation and lessons can be learned from there, including abolishing a monopoly on gas export and requiring direct sales from production companies.

Morocco is developing its own LNG import terminal, which will be connected to the GME pipeline from Algeria to Spain, potentially including underground gas storage. Tunisia has some gas production and import via the transit pipeline from Algeria to Italy. A new gas pipeline from Algeria to Italy (Galsi), with a connection to France (Corsica), is planned, but not yet implemented. A direct gas pipeline from Algeria to the mainland France is not possible at present due to the deep water between the two countries, which is the reason for the very short range LNG transport between the two countries. Bottlenecks between France and Spain and the lack of a pipeline between Italy and France are hindering a full gas ring in the Western Mediterranean basin.

Algeria is the physical gas hub in Western Mediterranean and can develop also to a market hub if market rules equivalent to the EU rules are implanted in Algeria, Morocco and Tunisia, including third party access to infrastructure.

Table 24: Algerian Hub barriers & opportunities for trade

		To		
	Barriers & opportunities for trade	Algeria	Morocco	Tunisia
From	Algeria	<u>General:</u> New resources potentially far away from consumption or export terminals thus a need to optimize infrastructure Low private investment; Domestic Insecurity; Water depth to France ; Shale gas need for water	<u>Political</u> (Tense relations with Algeria over Western Sahara). Availability of gas Transit agreement	<u>Commercial:</u> Import from Algeria costly Availability of gas Transit agreement
	Morocco	<u>Political</u> (Tense relations with Algeria over Western Sahara). <u>Availability of gas:</u> No reserves	Need for development of national gas transmission system	Competition on transit fees from Algeria when present agreements expires

Tunisia	Availability of gas: few reserves	Competition on transit fees from Algeria when present agreements expires	Development of underground gas storage

Table 25: Quick wins Algerian hub

Quick Wins	Private companies in Algeria allowed to export to EU (replica of Norwegian agreement with EU) Creation of internal gas market in Algeria Third party access to gas transmission in Algeria, Morocco and Tunisia Commercial backhaul to Morocco from Spain Morocco increase offtake from Algeria Tunisia increase offtake from Algeria Commercial backhaul to Tunisia from Italy Gas Storage in Algeria, Morocco, and Tunisia
Others	Subsidy reform and enhanced RE in Algeria Attract private investment Trans Saharan gas pipeline Nigeria- Morocco gas pipeline

10.2 Egypt hub and Mediterranean hub

Egypt has an ambition to become an energy hub for oil, gas and electricity. With the Suez Channel, a major part of oil supply from Middle East to Europe pass the country. Also, large volumes of LNG from Middle East pass the Suez Channel.

The gas sector has had an uneven development, with the creation of LNG and pipeline export a decade ago, shifting to LNG import during the last years and with the possibility of exporting for some years with the Zohr gas field coming on stream within the next years.

The location of Egypt allows for possibility to bridge gas from the Gulf to Europe and to import gas from offshore fields in the Eastern Mediterranean. This is not least due to the development in offshore pipeline technology which now, in principle, allows for a direct offshore pipeline from Egypt to Europe and for the import of gas from the offshore gas fields. Furthermore, the existing LNG export terminals can be used for export to Europe or other destinations until a pipeline could be established. The Arab gas pipeline from Egypt via Jordan to Syria can be connected to Iraq and thereby create a connection North of the Gulf as Iraq is already connected to Iran. Libya can also supply gas to Egypt and in the longer term this could create a North African pipeline. In the longer term, Egypt can also be connected to Sudan.

An Egypt gas hub will be competing with Turkey as an entrance to Europe and also with direct offshore gas pipelines from Israel, Libya and Cyprus to Greece and further to Italy. However, neither Turkey nor Greece has the same advantages of having a large indigenous gas production.

Therefore a gas hub in Egypt can be started in Egypt itself by allowing direct gas sales from producers to large industries and thuscreate a local price signal. As in Europe such direct trading can be gradually expanded to smaller consumers.

Figure 45: Map of Egypt hub

Source: WorldBank

Table 26: Egypt Hub barriers & opportunities for trade

	To				
Barriers & opportunities for trade	Egypt	Jordan	Lebanon	Syria and Iraq	Israel and Palestine

From	Egypt	Payment arrears to international companies Low private investment; Domestic Insecurity;	Lack of gas supply in Egypt	Lack of gas supply in Egypt	Iraq has own reserves	Israel started own gas production
	Jordan	<u>Availability of gas:</u> No reserves	LNG import established			
	Lebanon	Gas reserves not yet identified	Not relevant	Preference for export to EU via Cyprus		
	Syria and Iraq	Security issue and ongoing wars. Lack of pipeline from Iraq to Jordan				
	Israel and Palestine	Offshore pipeline				

Table 27: Egypt Hub barriers & opportunities for trade

				To	
	Barriers & opportunities for trade	Egypt	Libya	Saudi Arabia	Sudan
From	Egypt	Payment arrears to international companies Low private investment; Domestic Insecurity;	Lack of pipeline	Lack of pipeline	Distance and Egypt network
	Libya	Security issue, Need for field development in East	East-West connection is weak	N/A	Distance
	Saudi Arabia	Political relation between KSA and Egypt Most KSA reserves in Gulf region, requires long pipeline	Not relevant		
	Sudan				

Table 28: Egypt quick wins

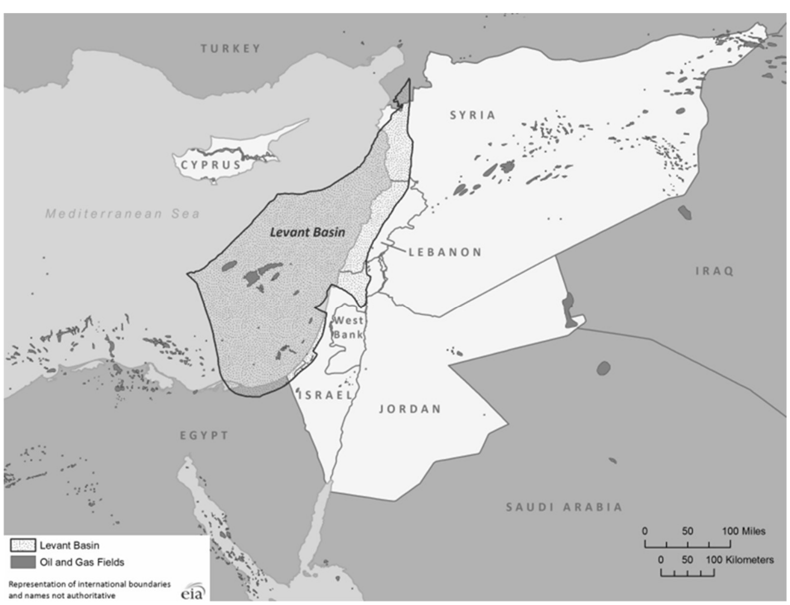
Quick Wins	New gas fields like Zohr field onstream followed by smaller fields Revitalize LNG export from idle terminals Revitalize the Arab pipeline and prepare for reverse flow from Iraq via a new pipeline. Establish direct gas sales from producers to large industries Libya to Egypt gas pipeline Gas storage for peak demand Israeli export via Egypt
Others	Egypt to Europe gas pipeline Qatar – AGP link P/L (via KSA) Qatar – Cairo link P/L (via KSA) Egypt-Sudan gas pipeline

10.3 Eastern Mediterranean hub

The eastern Mediterranean is an area which is rich in gas and presumably oil, and a number of discoveries significant to the region have been made over the past decade.

The central part of the eastern Mediterranean is the area called the Levant basin (as seen in figure 48). In this area there is a large number of proven gas reserves and estimates of more. US Geological Survey estimate that the reserves in the Levant basin are 3454 BCM. This is an average estimate and approximately one third of these gas reserves have been discovered so far. Although these do not compare to the ones found elsewhere in the MENA region, they might affect export from the MENA region and influence the feasibility of export cases to countries like Egypt, Jordan and Turkey and therefore these reserves are important to include in the study at hand.

Figure 46: Overview Levant Basin



Source: U.S. Energy Info. Admin., IHS EDIN

The Levant basin crosses a number of borders in a historically very tense region. Oil and gas exploration is currently being conducted in:

- Israel
- Egypt
- Cyprus
- Lebanon
- Gaza

All of these territories in the region are exploring oil and gas opportunities in the area but the level of maturity varies.

Forty five percent of the Levant basin falls within Israeli territory. This is by far the country which has reached the largest level of maturity in developing the offshore gas fields in this area. In the Israeli sector, two fields are already up and running, Mari B (28 BCM - depleted) and Tamar (311 BCM) and the planning of Tamar phase II is ongoing as well as the large Leviathan field (538 BCM). Israel and Cyprus are investigating their possibilities and have recently (April 2017) announced their non-binding intentions to connect their resources to the European market (illustrated below in Figure 48).

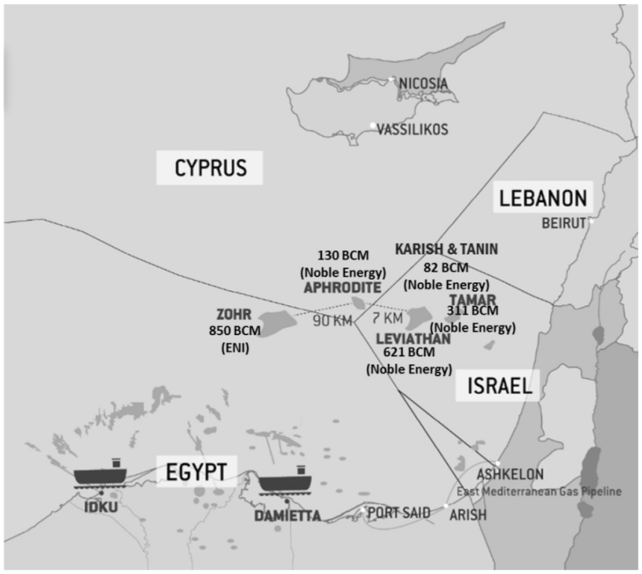
Figure 48: EASTMED and Poseidon Pipelines

Source: www.igi-poseidon.com

Egypt and Cyprus are next in terms of maturity and are in the process of developing the Zohr field (850 BCM) as a fast-track project, and the Aphrodite field (141 BCM). Tamar, Leviathan, and Aphrodite are all operated by US-based Noble Energy. These three developments are important to the local market so there will be a significantly reduced import of gas in this region.

Lebanon and Gaza have identified licenses and operators but the political climate prolongs the development. Lebanon is currently in the process of developing an offshore oil and gas sector and f defining the political and legal framework and might be self-sufficient within a decade if they are successful in the political process and exploration. Gaza has two smaller fields which they have not been able to develop so far. Therefore it is more likely that they will import gas from Israel. For illustrative purposes the most significant findings of natural gas are shown in **Error! Not a valid bookmark self-reference.**, counting Zohr (Egypt), Leviathan & Tamar (Israel), Karish & Tanin (Israel), Aphrodite (Cyprus).

Figure 49: Significant discoveries in the Eastern Mediterranean



Source: Middle East Economic Survey

Gas export agreements

At present the most mature fields in the Eastern Mediterranean are the Tamar field in Israel which is already producing and about to start the development of a second stage, and the Zohr & Leviathan fields in Egypt and Israel which are being developed simultaneously. The Aphrodite field in Cyprus will be dependent on further discoveries in Cyprus, Israeli, or Egypt..

There are a number of different agreements and letters of intent in place for the export of gas already (summarised in Table 29).

Table 29: Summary of gas export agreements in the Eastern Mediterranean

Field	Recipient	BCM	Type of agreement	Year
Leviathan	NEPCO	45	GSPA	2016
Tamar	BROMINE & Arab Potash	1.8	GSPA	2014
Tamar	Dolphinus Group	5	Signed agreement	2015
Leviathan	Dolphinus Group	50	LoI	2015
Leviathan	BG (Shell)	106	LoI	2014
Tamar	Union Fenosa Gas SA	70	MoU	2014
Unspecified Israeli field	Palestine Authority	4.5	Gas export agreement	2014
Unspecified Israeli & perhaps Cypriot field	Turkey	100[1)]	Normalisation deal between Israel and Turkey	2016

1)	This is an estimate as agreements are not in place yet but the amount of gas exported will have to be substantial to justify the infrastructure to Turkey and the project will be competing with the BG (Shell) LoI

These initial agreements add up to 282 BCM, of which the 52 BCM are signed agreements.

We conclude that while there are volumes available for trade, the region is competing against Europe in attracting these resources through pipelines, or the world market if the Egyptian LNG export terminals are used. As shown earlier, regional export terminals via LNG greenfield facilities in the region would not be attractive. Volumes could be tied up with the Arab Gas Pipeline. In doing so reverse flow possibility should be ensured.

10.5 Libya trading hub

Libya is already connected to the EU gas market via the Green Stream pipeline. Furthermore an idle LNG export a terminal exists which can be revitalized. At present there is no trade with other Arab countries.

The large gas reserves in Libya, combined with a small population, are the main reason to create a trading hub in Libya. Geographically, Libya can become the bridge between the Algeria and Egypt hubs, but this will need strengthening of the East-West connection.

Recent gas finds offshore Libya shows that exploration and production can take place even during a period with internal conflict and lack of clear political leadership. In fact the oil and gas production may be the only unifying sector in the country[28].

Figure 50: Map of Libya hub

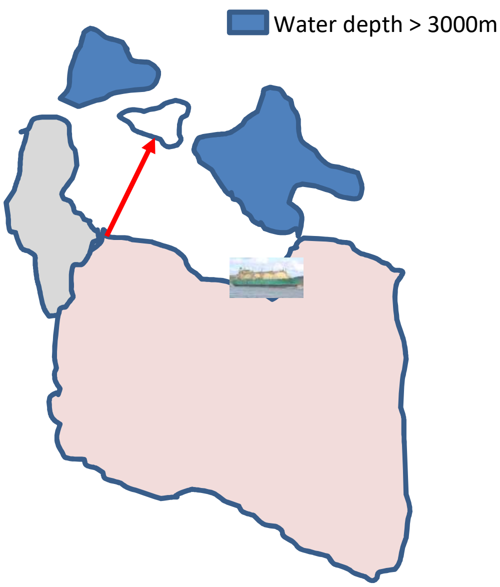


Table 30: Libya Hub barriers & opportunities for trade

		To		
Barriers to trade		Libya	Tunisia	Egypt
From	Libya	Low private investment; Domestic Insecurity;	Lack of gas pipeline. Could be done as reserves flow via Italy	Lack of gas pipeline

[28] Upstream 31st of March 2017 page 11.

	Tunisia	Few reserves	
	Egypt	Lack of gas pipeline	No connection, Offshore pipeline could be possibility

Table 31: Quick wins Libya hub

Quick Wins	Establishing new pipeline between Libya and Egypt Commercial reverse flow in Green stream to cover short term gas deficits in Libya until new fields are in production Revitalizing existing LNG import facility
Others	

10.6 **Iraq trading hub**

Iraq has some of the largest gas reserves in the region. At present gas is being flared. A pipeline connection between Iran and Iraq has been established but is not yet in use. Kuwait prefers LNG import rather than import from Iraq.

Geographically, Iraq is located with borders to Iran, Turkey, Syria, Jordan, Saudi Arabia, Kuwait with little access to the Gulf, making it difficult to establish LNG export and import.

Establishment of an Iraq gas trading hub can be initiated internally in the country by direct sale from producers to large industries and power plants without price regulation. Furthermore, prohibiting gas flaring by law within a reasonable time frame will bring large quantities of gas to the market.

Establishing a pipeline from Iraq to Jordan and connecting to the Arab gas pipeline can give access to markets in Jordan, Syria, Egypt and Israel. The establishment of a gas pipeline from Iraq to Turkey can give access to the EU gas market.

Iraq is well located for gas storage facilities and due to the climate there is a need for gas for heating during winter.

Figure 51: Iraq hub

Table 32: Iraq Hub barriers & opportunities for trade

		To			
	Barriers and opportunities for trade	Iraq	Iran	Syria	Jordan
From	Iraq	Flaring of gas Low prices Internal conflicts in the country	Not relevant in the short term	Lack of pipeline Security	Lack of pipelines Security
	Iran	Pricing – ability to pay in Iraq Iran own production and domestic needs	Embargo	Transit via Iraq	Transit via Iraq
	Syria	Lack of pipeline. Lack of availability of gas.	Not relevant		Arab Gas Pipeline to be revitalized reverse flow a possibility
	Jordan	Lack of pipeline. Lack of availability of gas.	Not relevant	Arab Gas Pipeline to be revitalized	

Table 33: Quick wins Iraq

Quick Wins	- Reduce gas flaring within a reasonable time frame – set target dates - Direct gas sale to large industries without gas price regulation - Establishing gas pipeline from Iraq to Jordan and connecting to the Arab pipeline
Others	- Gas pipeline to Turkey for export to EU

10.7 Qatar trading hub

Qatar has the second largest gas reserves in the region after Iran, and by far the largest gas reserves per capita. Qatar will is therefore be a gas exporter and the main issue is the timing of production and a decision if gas export should mainly take place as LNG.

Qatar is the leading gas exporter in the Middle East as well as to Arab countries, UAE and Oman via the Dolphin gas pipeline. It can be argued that Qatar is already a gas trading hub. However no uniform gas price exists as Qatar companies Qatar Gas and Ras Gas have different contracts with buyers including destination clauses.

Apart from direct gas export, there is indirect gas export via chemical industries and aluminium and petrochemical production, including gas to liquid. This creates an indirect connection to the global gas market.

Geographically, Qatar is located between countries that all have large gas reserves, which means that gas export has mainly been as LNG. This has the drawback of being dependent on free access tothe Gulf via the Hormuz Strait. This may have been the reason for establishing the Dolphin gas pipeline to UAE and Oman, which gives access to a gas market outside the Strait.

Qatar has had a limit on gas production, partly due to technical reasons, partly to avoid becoming too dominating in the global gas market and partly for political reasons. It has recently (April 2017) been announced that new gas production will be initiated and thus lifting the moratorium. This will allow for increased export of initially up to 20 bcm/y either as LNG or via pipelines to neighbouring countries such as Bahrain, Saudi Arabia, UAE, and Oman. Export to markets further away will require transit via e.g. Saudi Arabia.

The creation of a Qatar gas hub can be done fast by selling of spot LNG cargoes in Qatar, which will require a certain overcapacity in the production.

Figure 52: Qatar trading hub

Source: WorldBank

Table 34: Qatar barriers & opportunities for trade

		To					
	Barriers to trade	Qatar	Saudi Arabia	Bahrain	Oman	UAE	Kuwait
From	Qatar	Policy on gas production – Moratorium Opening of production to international companies,	Political Lack of gas pipeline	Political Lack of gas pipeline	Transit vis UAE	New pipelines required	Political New pipelines required
	Saudi Arabia	Availability of gas	Policy on gas production	Availability of gas Lack of pipeline	Availability of gas	Availability of gas	Availability of gas
	Bahrain						
	Oman						
	UAE						
	Kuwait						

Table 35: Quick wins Qatar trading hub

Quick Wins	- Direct LNG selling from Qatar FOB Qatar ports – publishing prices - Lifting moratorium on increased gas production in Qatar - Fully utilize increased capacity to UAE and Oman - Pipeline to Bahrain
Others	- Pipeline to Saudi Arabia - Pipeline to Kuwait

Trading hub Iran
Iran is a leading gas producing country with the world's largest gas reserves and the third largest gas production. However, international trade is limited and most of the gas is being used internally. This is mainly due to the long term embargo against the country but also due to lack of export infrastructure.

Iran has the possibility to develop its gas production and hereby create the basis for export and the creation of a gas trading hub.

The first priority after satisfying the demand of the domestic market, has been to support increased oil production by using gas. Secondary and more medium term goals are to establish gas export possibilities.

Geographically, Iran borders a number of countries needing gas import such as Turkey, Armenia and Iraq where gas pipelines already exist and Pakistan where no pipelines have been established despite decades of planning. Further gas transit has taken place from Turkmenistan to Turkey. Iran has started to construct an LNG export plant but it has not been finalized due to the embargo. New pipelines to Oman and Kuwait among others have been discussed. And long-distance export to India has been discussed via Pakistan or via Oman and offshore.

The gas pipeline to Turkey can give access to the EU market while thegas pipeline to Iraq can give access to the Mediterranean gas market, including Egypt if a pipeline from Iraq to Jordan is connected to the Arab gas pipeline.

With the lifting of the embargo a trading hub can be established, initially with creation of an internal market for gas in Iran, and with large industrial consumers and power sector. In the northern part of the country it will be possible to create a hub which could also include gas from Turkmenistan. Iranian and Russian gas is already competing in Armenia. With the right price signal in this part of the country it will be possible to give incentives to a.o. underground gas storage facilities.

Figure 53: Iran trading hub

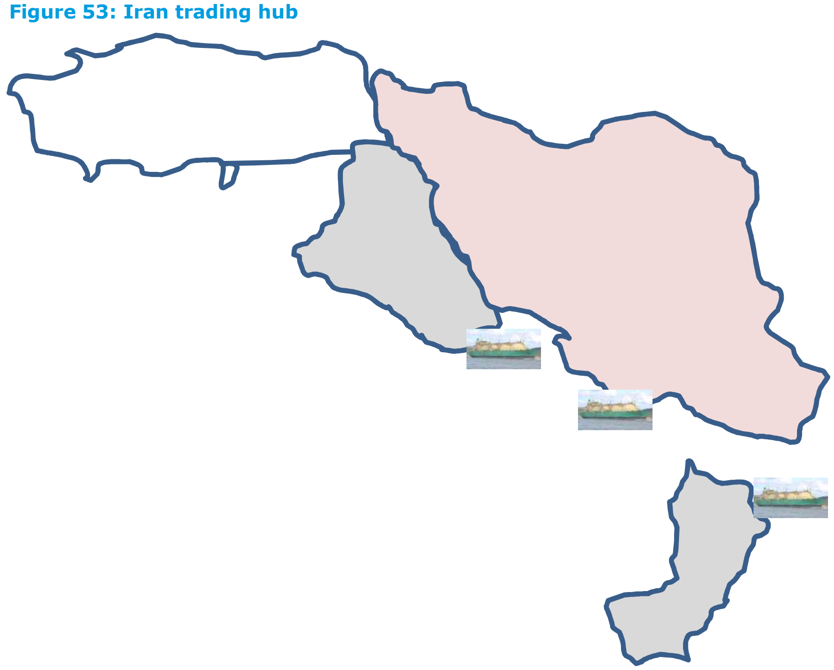


Table 36: Iran barriers & opportunities for trade

		To			
	Barriers & opportunities for trade	Iran	Iraq	Oman	Kuwait
From	Iran	Embargo Lack of technology for LNG plant	Price in Iraq Instability in Iraq draws on finances.	- Political - Competition from Qatar via Dolphin pipeline - Offshore gas pipeline forced through deeper waters	Political - preference for LNG import
	Iraq		Gas flaring Priority to oil	NA	Pipeline technically possible but political preference for LNG import
	Oman	Not relevant	Not relevant	Challenged by complicated fields and high production costs.	LNG export a possibility.

Table 37: Quick wins

Quick Wins	Establishing of northern gas hub at border to Turkey will meet gas from Turkmenistan, Russia and Azerbaijan Opening of deliveries through gas pipeline to Iraq Finalizing LNG terminal and give access to global market Reduce flaring could make volumes available
Others	

10.8 **Algeria**

10.8.1 Data and assumptions

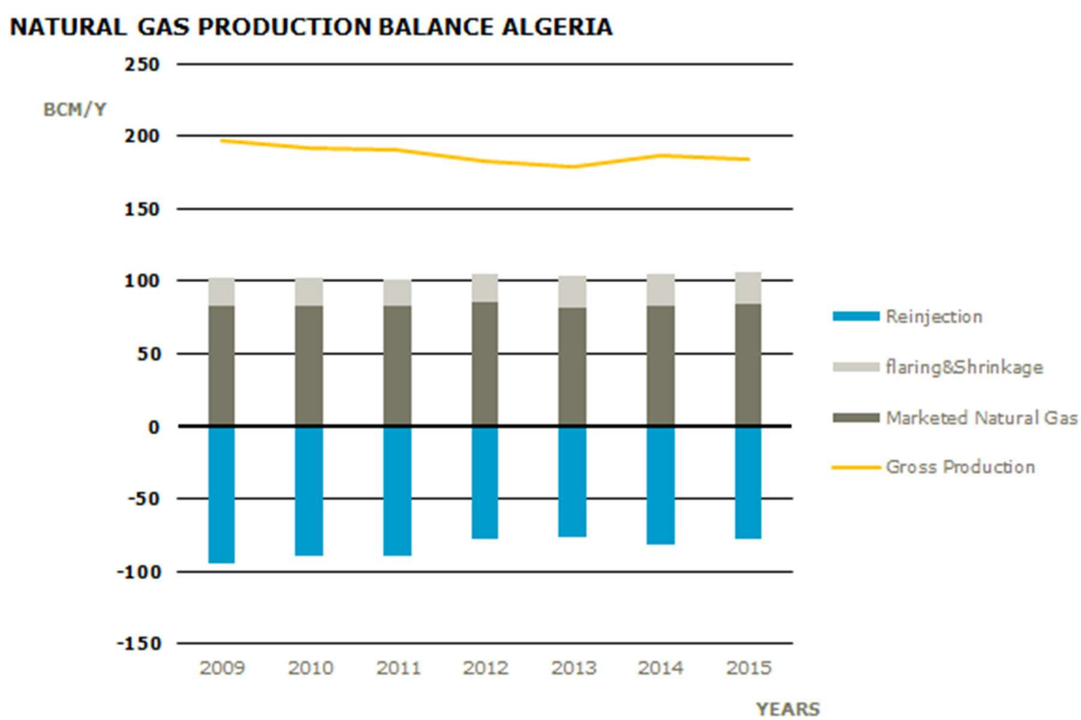
Historic data has been sourced from OAPECs databank. To project supply, we assume that existing production is slowly declining by 1% per year including Hassi R'Mel, while we add the fields that we expect to be brought into production. For these fields we assume a ramp up to plateau over 3 years and that they will be on plateau until 2030. Sources for these fields are public and shown in Appendix 2.

To project demand we used the results from modelling the power sector and estimates made by the Algerian regulator in other sectors.

10.8.2 Gas supply

Sustaining the net marketed production of 80-84 bcm/y in Algeria is challenging. Following a series of unsuccessful licensing rounds and increased security concerns following the attack in In Amenas, marketed production has remained stable at about 80-83 bcm per year over the past couple of years. Apart from the net production, a number of other components should be taken into account in the upstream sector of Algeria, most importantly the volumes for reinjection into the Hassi R'Mel field. These volumes are substantial and almost reached 100 bcm in the past, underlining that reinjection is necessary to keep the Hassi R'Mel producing at the required levels. However reinjected volumes have decreased from 89 bcm in 2009 to 77 bcm in 2015. One hypothesis could be that the short term supply for the growing domestic need is being prioritized on behalf on long-term production at the Hassi R'Mel.

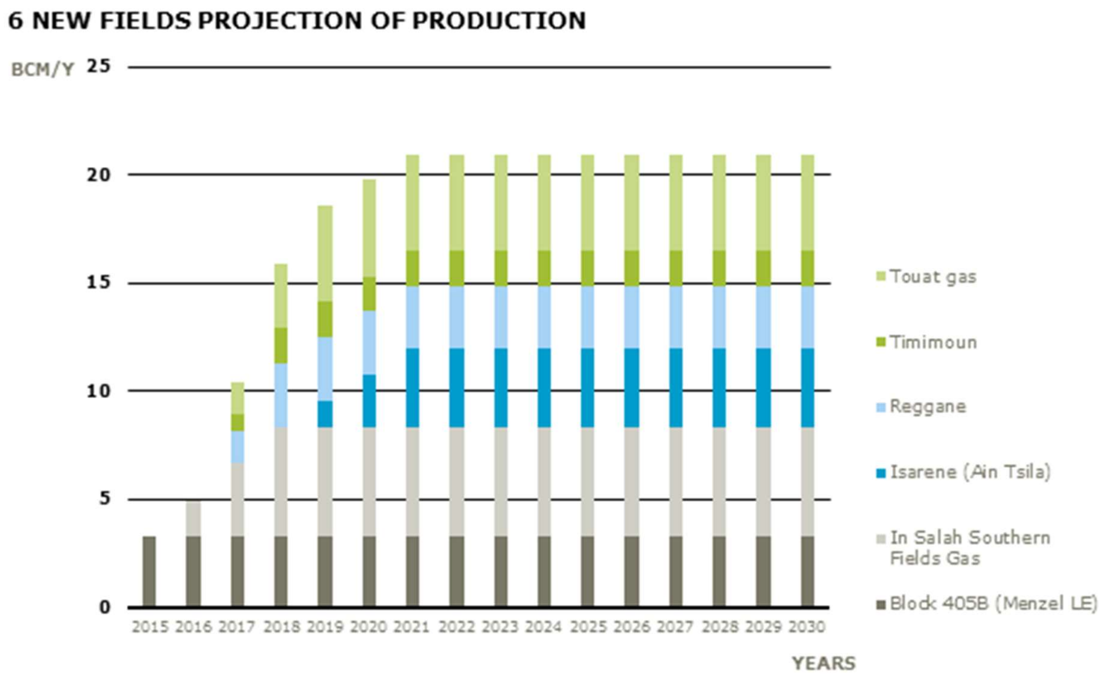
Figure 54: overview of gross production Algeria



Source: OAPEC

In addition to Hassi R'Mel, a number of fields are under development and expected to go into production over the next 4-5 years. We have summarised these fields in Figure 55 below.

Figure 55: Algeria gas production 5 new fields



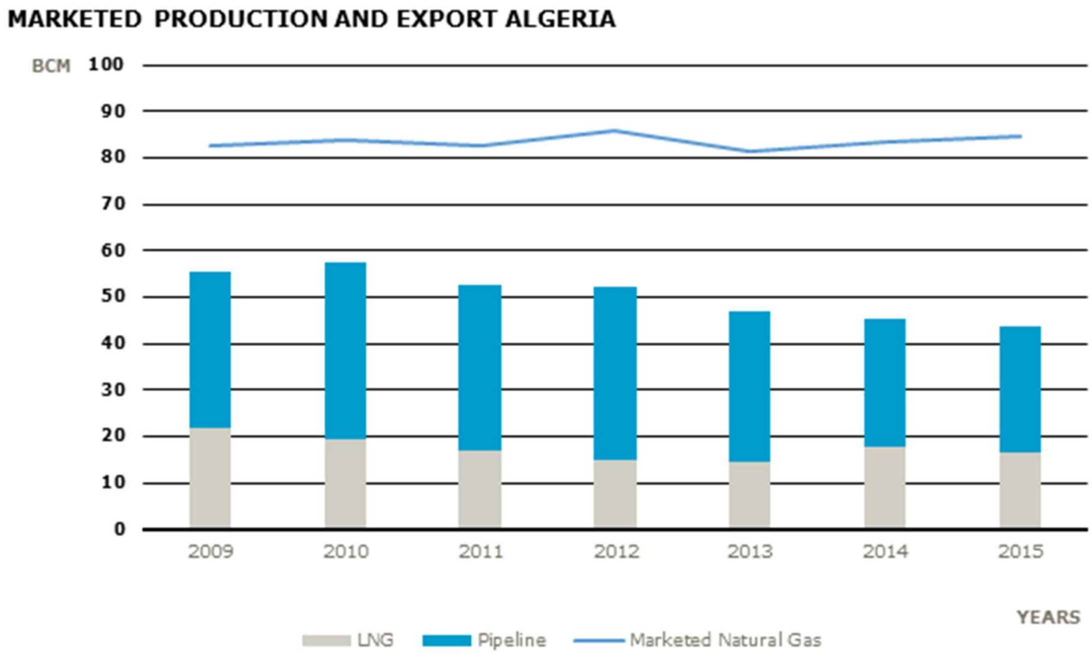
Source: Own Calculations with std. production profile, annual accounts of upstream companies.

Apart from that there is little in the current outlook or policy catalogue which points to increased production and E&P activity. The IEA has published their own forecast of Algerian production which is constant from 2015 to 2020 and increasing to 105 bcm per year from 2020 to 2030. This corresponds very well with the addition of the 6 fields of approximately 20 bcm in the investigated period. Algeria itself is having a higher expectation of around 120 bcm per year in 2030.

10.8.3 Gas Export

A major share of the Algerian gas production is eventually exported, both through liquefaction facilities and pipelines. However tExports have been decreasing for several years.
The historical developments in export compared to the marketed natural gas are illustrated below.

Figure 56: Marketed Production and Export Algeria



Source: OAPEC

The decrease in exports has been matched by an increase in demand, indicating that volumes are now being consumed domestically.

10.8.4 Gas Demand

Consumption is constituted by the power generation sector, Sonatrach's own consumption, the industries utilizing gas, and some utilities supplying gas to households. In order to project the development of these sectors, we turn to the regulator CREG which has published the following forecasts as presented in the table below, reproduced from Aissaoui 2016.

Figure 57: Projections of gas demand 2017-2023.

			CREG projected annnual demand from 2014 estimate (bcm)			Corresponding annual average growth by period (%)		
	Actual 2014 (bcm)	CREG base year estimate for 2014 (bcm)	2017	2020	2023	2014-2017	2017-2020	2020-2023
Power Generation	15.7	14.5	15.9	18.3	21.4	3.1	4.8	5.4
Sonatrach's transformative industry	7.9	7.3	10.2	12.9	13.1	11.8	8.1	0.5
Other industries	3.5	3.2	4.2	5.3	5.9	9.5	8.1	3.6
Utilities' public distribution	10.4	9.6	11.5	13.1	14.2	6.2	4.4	2.7
Total demand	37.5	34.6	41.8	49.6	54.6	6.5	5.9	3.3

Source: Aissaoui 2016 OIES Troubling trends, troubling policies

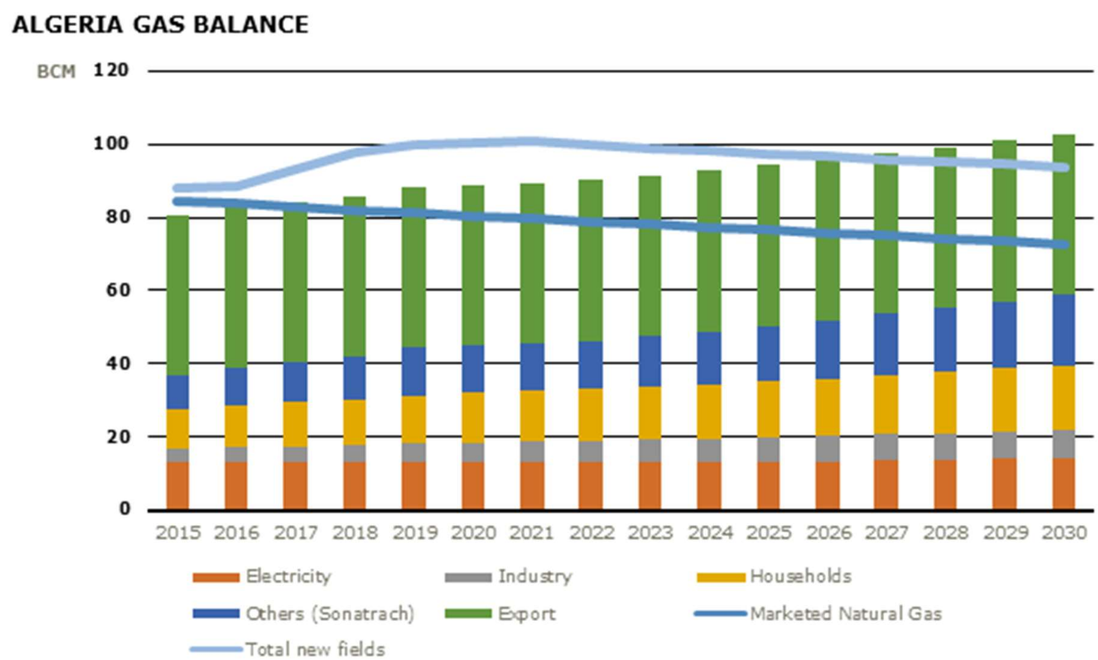
We have chosen to keep the growth rates for the period 2020-2023 for the remainder of the period until 2030. We note that the increase in gas demand in the power sector seems to be on the high side, and our own investigations of the power sector demand by usage of the PromedGrid model points to a lower demand. Implementing this into the demand projections gives some more space for increased exports and trade.

Conclusions availability of gas

10.8.4.1 Baseline scenario

Adding the projected production to projected consumption shows that the 2015 level of export can be sustained throughout most of the project period – however demand can increase beyond the estimates by the regulator – especially if subsidies are not addressed. Additional export of gas out of the MENA region will reduce the volumes available for trade within the MENA region.

Figure 58: Algeria gas balance



Availability of gas for regional trade may increase in the following scenarios:

- A low gas price environment in Europe could reduce the incentives for export of gas. For example, Sonatrach has been losing market shares to Gazprom in Italy with significantly reduced deliveries as a consequence. If the challenges for Sonatrach in Europe continues, with Norway and Russia pushing prices and volumes further south and the demand in the EU continuing its' de-route then incentives for trade with the neighbouring countries may increase along with the availability of gas.

- Production increasing up to the 120 bcm/y in 2030. This could be possible under the right conditions.

10.8.5 Valuation of gas and gas supply pricing

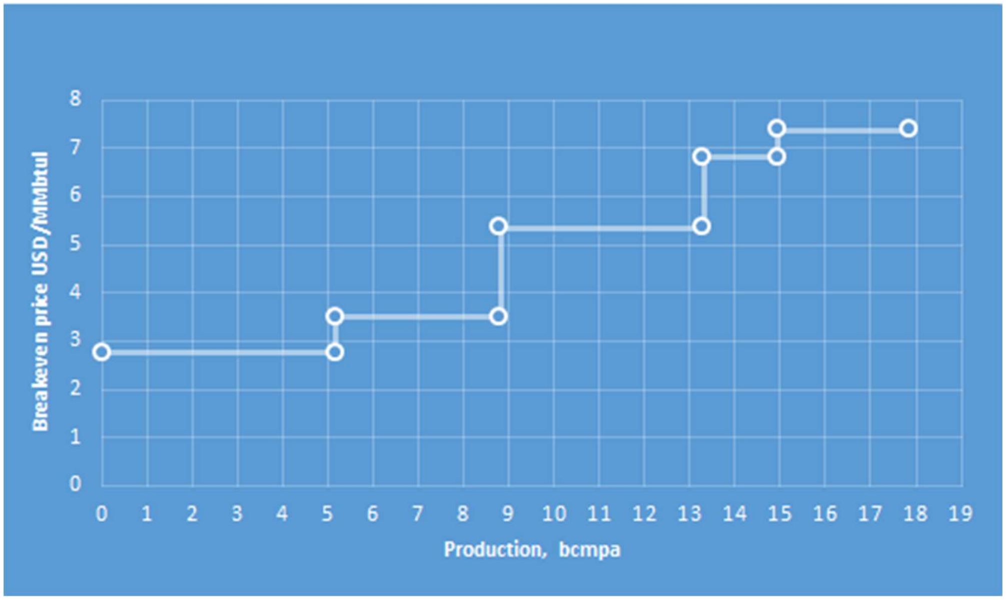
In order to understand the economic costs of gas, the value of gas and the relation to subsidized prices, we investigate the following benchmarks and indicators:

- Long run marginal costs of domestic gas production (calculated by a proxy of the 4-5 largest gas fields in the country)
- Value of gas in the power sector by replacing coal or HFO in power generation.
- Value of gas (netback) by exporting (LNG & pipeline) out of the region to European or Asian markets.

10.8.5.1 Supply of gas

Reviewing the production from the 6 fields added to the existing production projections shows breakeven prices as high as 7 USD/MMBTU.

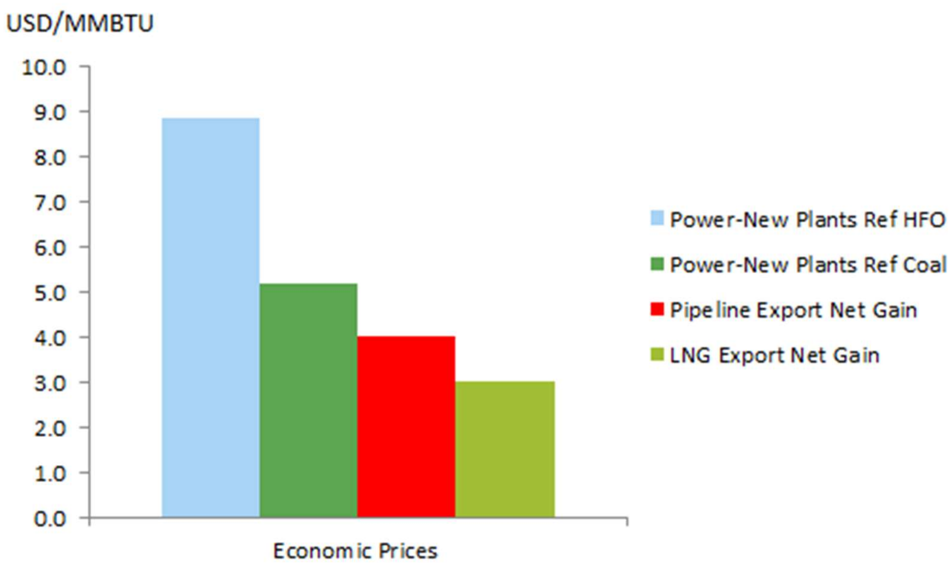
Figure 59: LRMC incremental production Algeria



These estimates are based on a Delphi survey of existing and future fields in Algeria produced by Aissaoui in 2013when the maximum price was in the range of 4-5 USD/MMBTU. The difference may be a result of associated infrastructure being part of the public available CAPEX figures for the fields.

10.8.5.2 Internal valuation of gas

The value of gas in power generation is based on efficiencies of 35% and 40% for a newly constructed HFO and coal power plant respectively, combined with the prices of 70 USD per tonne of coal and 300 USD per tonnes of HFO this gives values of gas ranging between 9 and 5 USD/MMBTU representing a relative favourable netback value of gas.



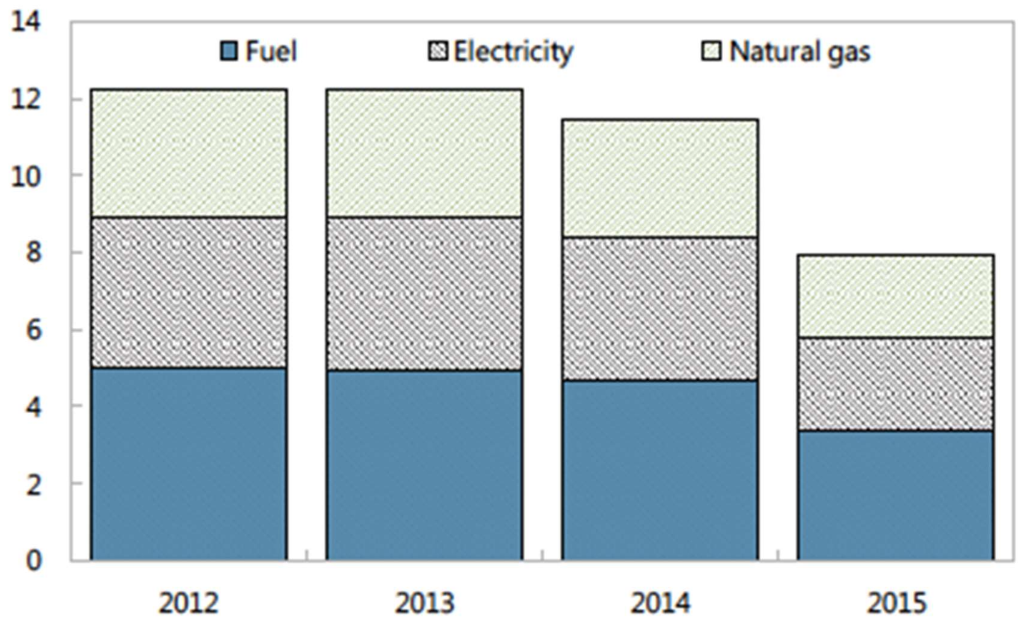
Considering CAPEX for the LNG terminal as "sunk" cost, the net gain from gas export considering a 2020 gas market price in Europe of 5 USD/MMBtu is below the netback value of gas as a substitute of coal in power production. The same conclusion can be reached considering gas export via pipeline to Europe. The described scenario clearly signals the economic advantage in the domestic usage of gas in the power sector.

10.8.5.3 Subsidies

The IEA estimates gas subsidies to 3.2 BUSD for 2014 in Algeria out of a total of 20.2 BUSD for all energy subsidies, mostly for petroleum products. The IMF Country Report for 2015 estimates the explicit subsidies (that are included in the budget and have a direct fiscal cost) for oil, natural gas and water to be 0.7 BUSD and implicit subsidies for these products 12.9 BUSD in 2015[29].

The cost of energy subsidies has declined sharply with the fall in oil and gas prices, reflecting the narrowing of the gap between the price of the energy supplied and the benchmark price (see Figure 60).

Figure 60: Energy subsidies in Algeria 2012-15. Percent of GDP.



Source: IMF Country Report No. 16/128. Algeria, Selected issues. May 2016.

The energy subsidies relate to oil, natural gas, and electricity, prices that are setadministratively below their market value. Although the 2016 budget law increased taxes on electricity and natural gas consumption, underlying tariffs have been frozen since 2005 and are well below supply costs. The gas price for feedstock is reportedly USD 0.5 - 0.6 per MMBTU.[30] [31]. This is lower than the estimated weighted average unit cost of existing production (USD0.6-0.7 per MMBTU, and much lower than the long run marginal cost of supply which we estimate to be USD 4-7 per MMBTU. Consequently, the state-owned utility Sonelgaz, which is responsible for natural gas and electricity distribution, has been running structural deficits. In addition to these implicit energy subsidies, the government provides smaller explicit subsidies for the public distribution of natural gas and water[32].

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[29] IMF Country Report No. 16/128. Algeria, Selected issues. May 2016.

[30] Hakim Darbouche: Gas-to-power in North Africa: Implications for gas exports and supply. Oxford Energy Forum August 2010.

[31] Ali Aissaoui: Algerian Gas: Troubling Trends, Troubled Policies. OIES PAPER: NG 108, May 2016.

[32] IMF Country Report No. 16/128. Algeria, Selected issues. May 2016.

The budget adopted by the parliament in Algeria in November 2015 raised taxes on fuels and electricity and in December 2015 the Government announced that Algeria would follow Morocco in gradually reforming subsidies.

The current low gas price is a barrier for development of new gas production and future gas trade. The subsidy removal program is its early stages with no specific targets.

10.9 **Morocco**

10.9.1 Data and assumptions

Historic data has been sourced from OAPECs databank. The LNG terminal Morocco is planning is timed for 2022 and the transit gas is assumed to continue.

To project demand, we used the results from modelling the power sector.

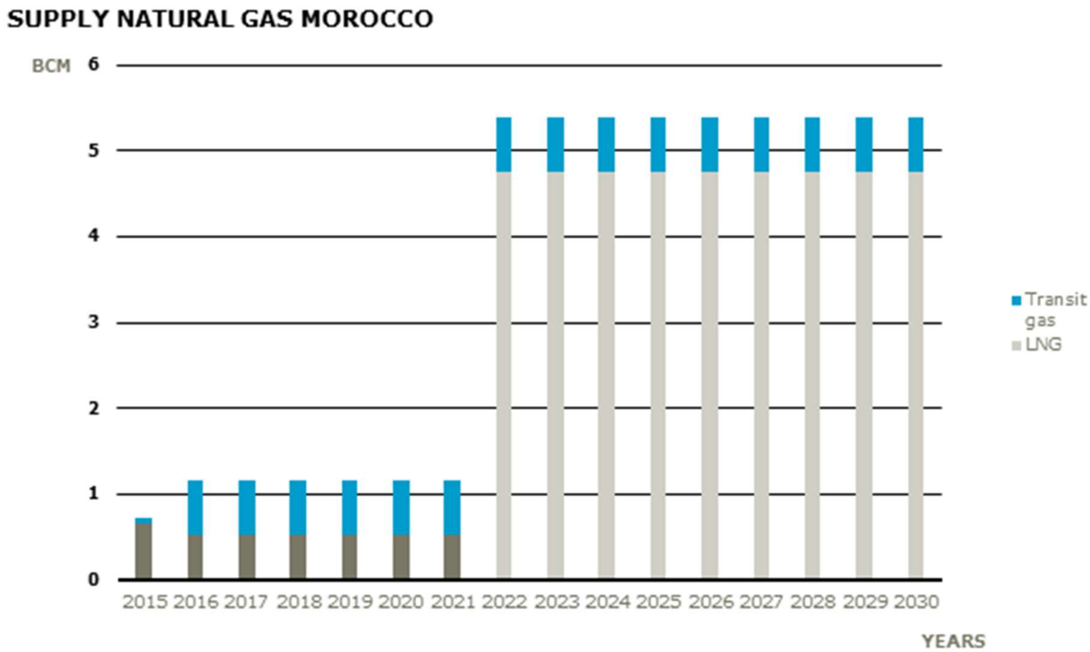
10.9.2 Gas supply

Morocco does not have any significant gas production. National policy towards gas exploration and production is characterized by the intensification of research and is aimed at encouraging international companies to invest in the oil and gas sector. Thispolicy is supposed to be supported by a new law for the gas sector which is to replace the current Hydrocarbon Law. However, development of gas production is a long way off and we therefore assume that no significant finds will be made in the study period.

Gas distribution in Morocco is very limited, since gas is only consumed near the GME transit pipeline to the Iberian Peninsula, and in the production basins of Gharb and Essaouira by some industries. The Moroccan state receives a transit fee from the gas purchasers in Spain and Portugal (7% of daily through-put, which have been declining). Since 2005, the transit fee has been in-kind and cash[33]. The in-kind gas is used by the power utility ONEE for electricity production. Thus as European demand is peaking in the winter, supply to Morocco by this agreement is also peaking. Total capacity of the transit pipeline is 11 bcm/y, 7% of this amounts to 0.77 bcm/y, as the current gas consumption in Morocco is 1.1 bcm/y. ONEE and Sonatrach signed a commercial gas supply contract for ten years (634 mcm/y) to be used exclusively for ONEE power generation, since the gas transit fee could not cover the additional needs of another gas-fired plant. ONEE also plans a 2400 MW gas-fired power plant based on imported LNG.
Both agreements will expire in 2021. From then on it is the intention to rely on LNG imports. In addition to the LNG import terminal, a number of CCTGs are planned, as well as an onshore transmission gas pipeline of 400 km and an underground gas storage. Below in Figure 61 the addition of the terminal is illustrated.

[3333] OIES: Natural Gas Markets in the Middle East and North Africa. 2011.

Figure 61: Gas supply Morocco



Source: OAPEC

10.9.3 Gas demand

The Government of Morocco is considering a LNG terminal to diversify supply and substantially increase supply to the power sector. Specifically Morocco aims for expanding usage of gas for power generation from 1.1 bcm/y in 2015 to 6-7 bcm/y in 2030. Thus this sector will be the main driver of gas demand in the future. Modelling the gas demand in the sector however shows that power consumption will only reach 3-4 bcm per year. This could of course change depending on by political decisions and decrees, especially with respect to coal fired power generation.

10.9.4 Gas infrastructure sourcing of gas – several possibilities

As mentioned earlier, LNG import solution has been proposed in other studies and can be carried out in different ways - either as a one large dedicated import facility in Morocco close to the power plants or as small scale LNG sourced from the Spanish Huelva LNG terminal.

There are also several possibilities to import from Spain:

Virtual import in the existing transit pipeline: Instead of building new pipelines the existing pipeline could be used for sourcing gas. Though the flow is one direction, from Algeria to Spain, imports from Spain can still be realized by having the network codes in place that allow Spain to “leave” some volumes in Morocco against receiving monetary compensation by Morocco. In the industry this practice is also known also backhaul or virtual flow. The drawback is that this scheme only works in periods when gas is being transported from Algeria to Spain. Another restriction is that the projected need for gas in Morocco is counter seasonal to the transport in the transit pipeline implying that the possibilities for virtual trade are highest whenever the need is lowest. Thus any volumes contracted in such an agreement are interruptible. To mitigate this challenge compressor stations on the Spanish side could be implemented and thereby ensure bi-directional flow in the pipeline.

10.9.5 Valuation of gas and gas supply pricing

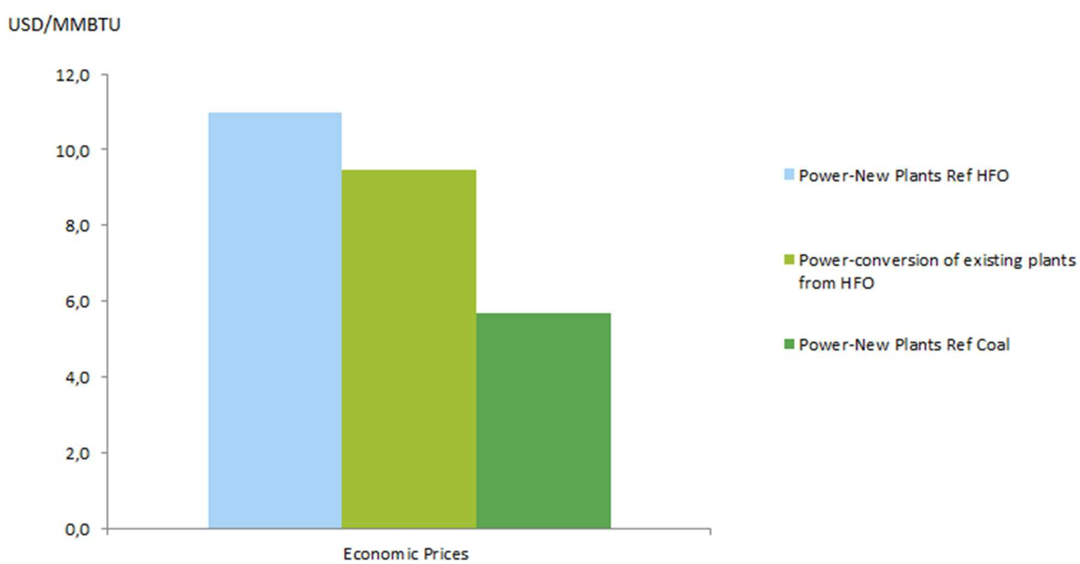
10.9.5.1 Supply of gas

As a supplement to future LNG imports, Morocco could, and does, import from Algeria. The price from Algeria should not be higher than the LNG import price. We estimate it to the price in Algeria plus transportation. In this manner the price of gas in Morocco converges to the European price as the price in Algeria is EU minus transport.

10.9.5.2 Internal valuation of gas

Featuring low efficiency HFO power plants, gas has the highest value in energy generation via CCGT plant among the North African countries. The same economic advantage of gas fired CCGT applies to the construction of new coal power plants.

Figure 62: Value of gas Morocco



Source: Ramboll.

10.9.6 Subsidies

Morocco first raised energy prices in 2012 and has continued the reform process since then, targeting all petroleum fuels except for LPG. In December 2014, Morocco announced that it was ending price subsidies for petroleum products (except for LPG) and would be adjusting prices twice a month from January to November 2015, after which prices would be deregulated. Prices of these products were fully liberalized at the end of, November 2015as scheduled[34]. The subsidy for petroleum fuels used in power generation was terminated in June 2014.

The IMF does not estimate any major subsidies in the gas sector, which leads us to conclude that ONEE pays the full costs of the commercial gas and for the transit gas. ONEE does receive direct budget transfers.

We conclude that there are no gas subsidies and this poses no barrier for future gas trade. Petroleum subsidies have alss successfully been removed.

[34] IMF country report no 16/35, Feb 2016.

10.10 **Tunisia**

10.10.1 Data and assumptions

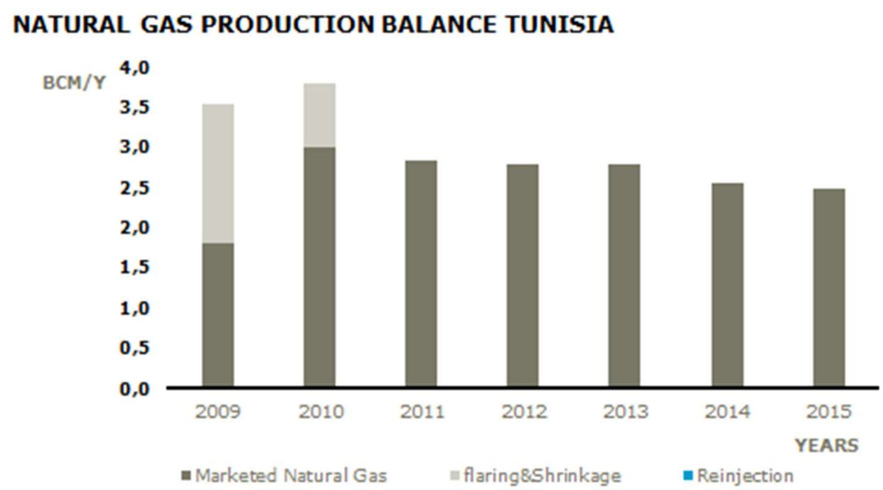
Historic data has been sourced from OAPECs databank. Current production is assumed declining with 2% per year, while new fields have been added. The new fields are the Nawara, Chaal Elyssa. The transit gas is estimated as 7% of 33% of the Algerian projected pipeline export as the future division between MEDGAZ, TransMed, and GME is unknown.

To project demand we used the results from modelling the power sector. For the industrial and residential sectors, results and inputs from the AFESD study have been utilized.

10.10.2 Gas Supply

Tunisia's gas balance is split 50/50 between indigenous production and imports. Additionally Tunisia has been receiving Algerian gas in lieu of transit fees (5.25-6.5 % of throughput[35]) since the commissioning of the Transmed pipeline in 1983, and contracted an additional 0.4 Bcm/year from Sonatrach in 1990, which has later increased. Without Sonatrach's additional deliveries, Tunisia could have suffered a serious supply shortfall in its domestic market. Lately transport in the Transmed to Italy has decreased significantly due to the market conditions, leaving little transit gas for Tunisia and implying that gas has to be bought on commercial terms from Algeria drawing on the agreement with Sonatrach.

Figure 63: Production balance Tunisia



Source: OAPEC

With little own production, and only one external supplier of gas,(Algeria), Tunisia's situation has for years been characterized by increasingly worsening security of supply. . Adding to this, high costs of imports from Algeria have been drawing on the country's' finances, particularly during periods with reduced Algerian exports to Italy. Thus initiatives have been made to increase domestic production, such as the South Tunisian Pipeline Project.

[35] OIES: Natural Gas Markets in the Middle East and North Africa. 2011.

Box 10: South Tunisian Pipeline Project

The South Tunisian Gas Pipeline Project

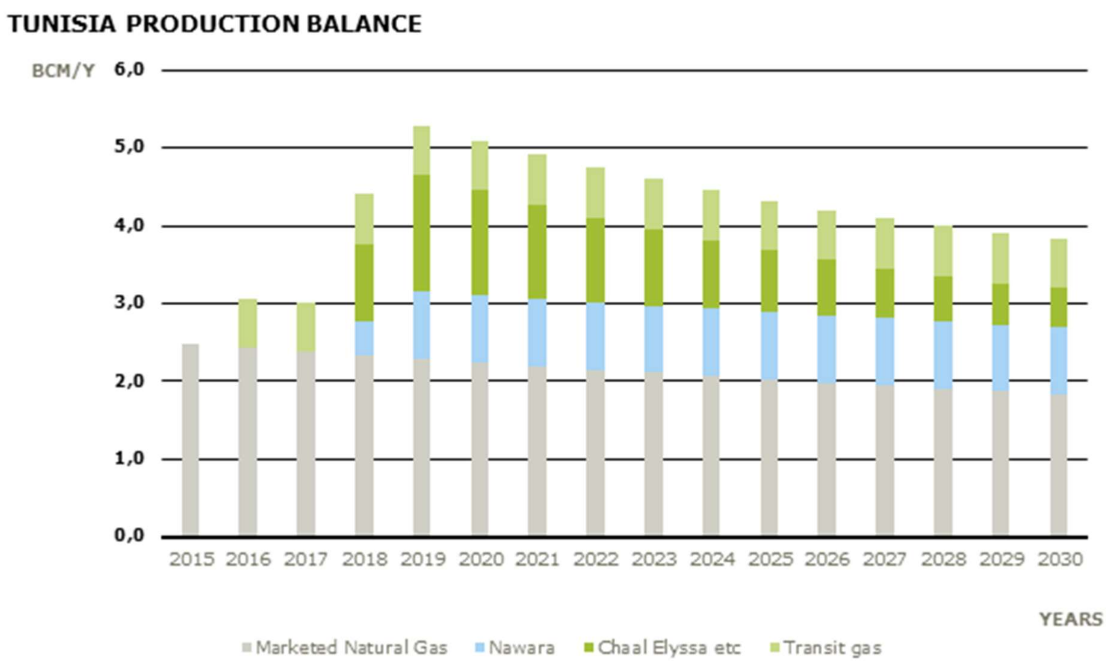
The24” pipeline will have a capacity of up to 10 million cubic metres per day and will run 370 km from Nawara in the south of the country to gas treatment plants at the port city of Gabés.Currently the sales gas available at Gabés is estimated at 2 MCM/d.

It will form part of the South Tunisian Gas Pipeline project (STGP), which also includes a central processing facility at Nawara and a gas treatment plant at Gabés. The project is being carried out by Tunisian NOC Entreprise Tunisienne d’Activités Pétrolières (ETAP) and Austria’s OMV in a 50/50 joint venture. The project CAPEX is estimated at 1.8b USD.

Source: OMV, Interfax, AfDB. 2016.

In addition to the onshore domestic projects there are also new developments offshore which could add to the supply of gas to Tunisia. The status of these is however not known.

Figure 64: Production balance Tunisia



Source: UNECE & ATPG 2015, AFESD 2013

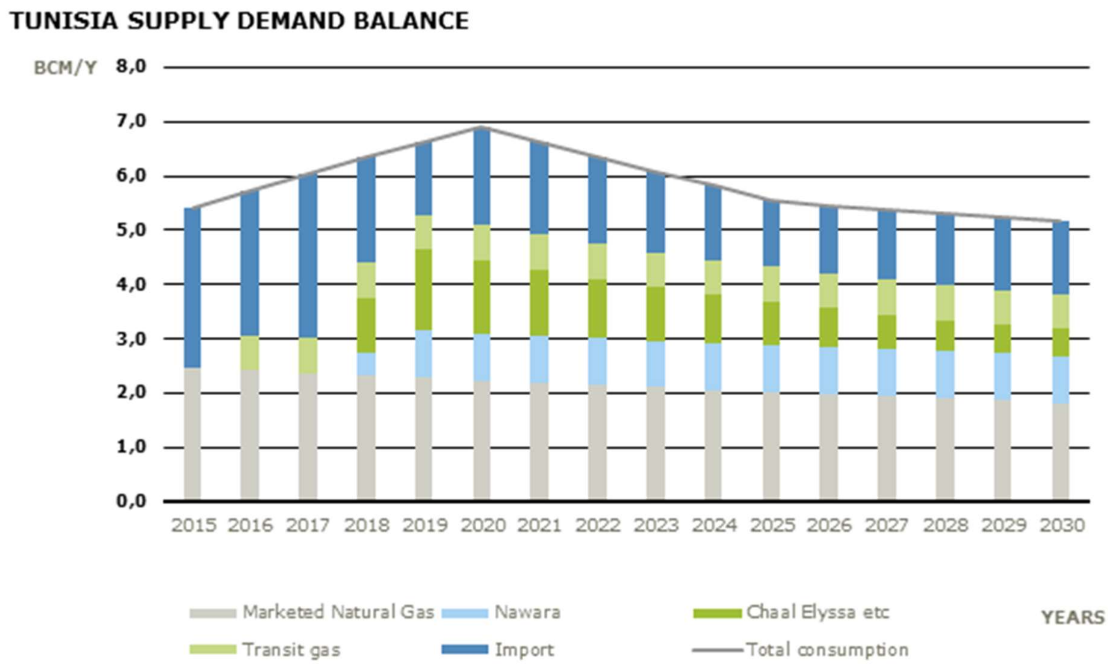
10.10.3 Gas demand

Gas is being used in the power, household and industry sector, with the power sector in particular almost completely dependent on gas. In Tunisia demand is expected to rise in all of the sectors and rise to 8.5 bcm/y in 2030. In particular gas for power is envisaged to grow during this period. Gas is used for baseload over the whole period. However in the summer period additional generation is required. Again, the transit agreements constrain the flexibility in the daily offtake implying that alternative imports must be planned for – or electricity generated by other fuels.

10.10.4 Gas supply and demand

Figure 65 illustrates potential developments of the supply and demand balance in Tunisia.

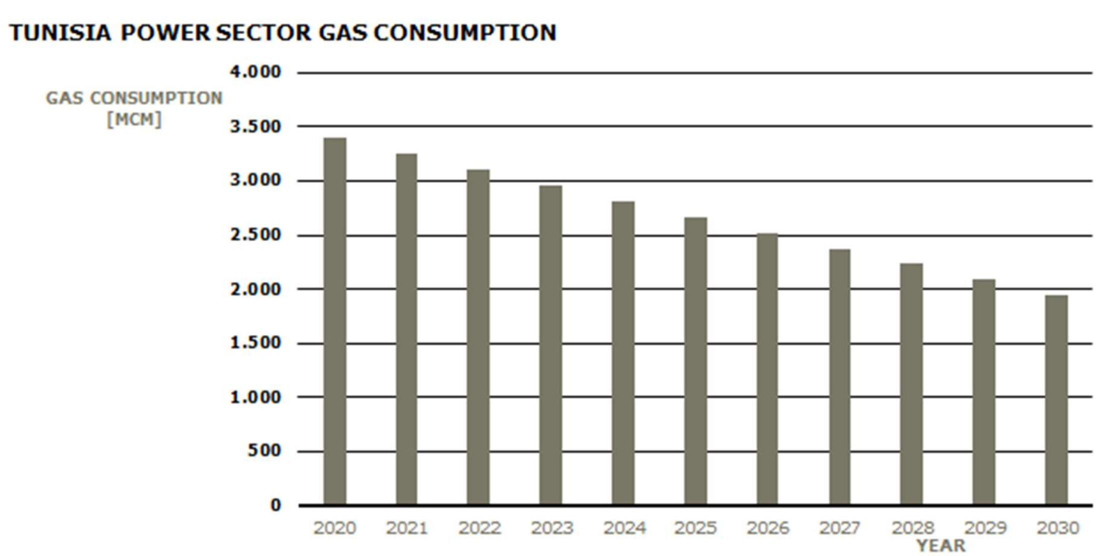
Figure 65: Tunisia Supply and demand balance



Source: Ramboll, CESI, AFESD, field developments see appendix 2.

Current fields are in decline butsome new fields will make up for this as discussed above. The forecasts however assume a stable contribution from the transit revenues. This is not necessarily the case. Recently low utilization of the TransMed from Algeria to Italy has implied low transit revenues in Tunisia. A crucial point is the demand for gas in the power sector. Demand in Tunisia is decreasing in the power sector due to efficiency improvements in power plants. As indicated above, the supply gap, although increasing, will be covered by Algeria.

Figure 66: Tunisia power sector gas consumption



Source: CESI

In addition to the domestic projects Tunisia enjoys several possibilities for diversifying its imports due to its location. The western Libyan fields are very close to Tunisia and a pipeline connection to Tunisia has already been proposed in a number of earlier studies but has so far not been implemented. Another option would be to convert a depleted oil or gas field into a gas storage which would serve as seasonal balancing tool and offer security of supply should the connection from Algeria be disrupted. A third possibility is the import of gas via a dedicated LNG terminal. Tunisia is investigating the possibilities for a FSRU solution but is far from a FID.

10.10.5 Valuation of gas and gas supply pricing

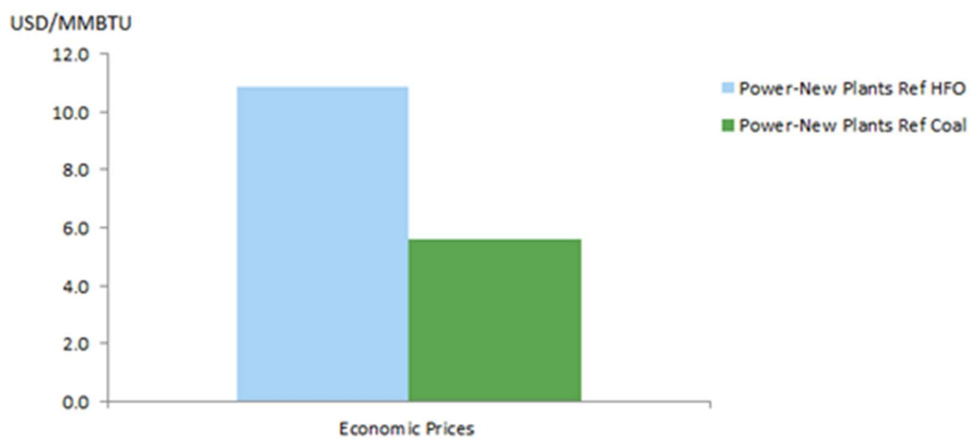
10.10.5.1 Supply of gas

Long run marginal cost of domestic production: The lifetime cost of Nawarra gas field is estimated to be around 3 USD/MMBTU. This is the only estimate we have from Tunisia and may not necessarily be representative.

10.10.5.2 Internal valuation of gas

The higher efficiency of newly installed CCGT plants over Coal fired power plants is reflected in a maximum gas economic value of over 5USD/MMBtu.

Figure 67: Value of gas Tunisia



Source: Ramboll

10.10.6 Subsidies

The Government has increased fuel prices on an ad hoc basis since 2012 albeit with some setbacks. In 2016, the government introduced a reform package that centres on establishing an automatic adjustment formula for petroleum products (gasoline anddiesel fuel), scheduled for implementation in stages and starting from July 2016 on a quarterly basis, then increasing onwards to a monthly basis from January 2017. This will be gradually extended to other petroleum products (natural gas, kerosene).[36]

Since 2003, the government has subsidized gas for the domestic market and for power generation. An estimate from 2008 calculates the subsidy to be 227 USD per toe (USD2.5 per MMBTU).

[36] IMF Country Report No. 16/138, June 2016

The gas subsidy removal program has no target level or date and could be a barrier for expansion of indigenous gas production and future gas trade while it is in place.

10.11 **Iran**

10.11.1 Data and assumptions

Current marketed production is assumed to be constant throughout the period. South Pars and Kish have been added from 2020 in the build-up and phases and the volumes are based on the NIOC.

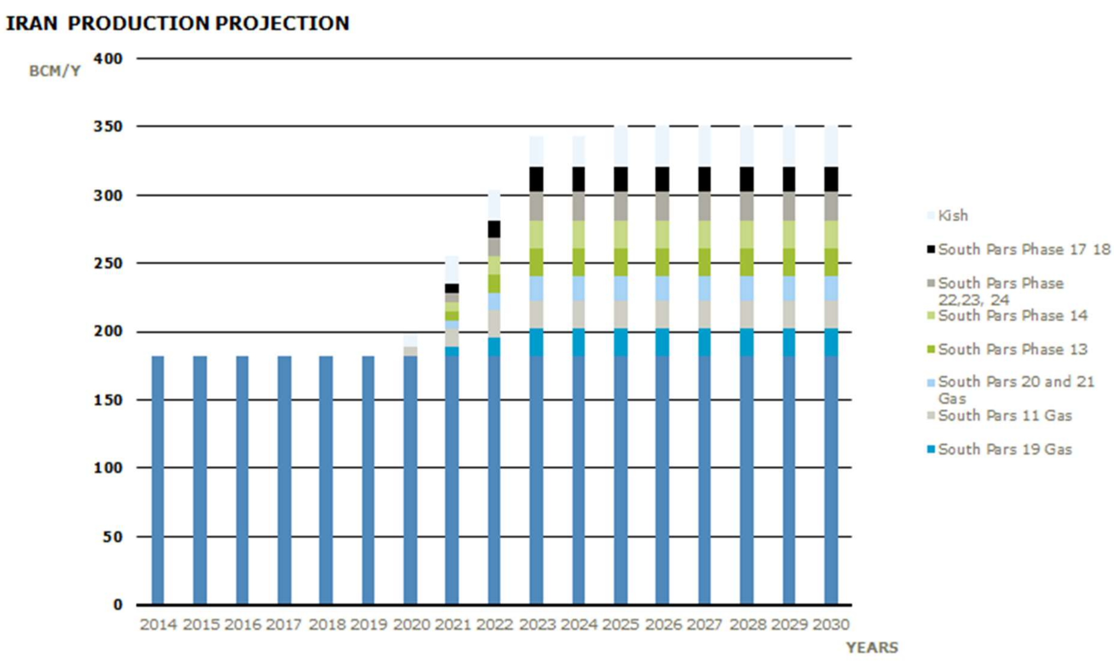
To project demand we used the results from modelling the power sector. For the remaining sectors we have not assumed any developments in the residential consumption as most of the country is already gasified. The industrial sector could increase significantly if Iran choses to monetize gas from products – but no plans have been identified for this. To capture total demand in 2030 we have taken a top-down approach, comparing Iran with Russia and a number in terms of consumption per capita resulting in approximately 250 BCM in 2030.

10.11.2 Gas Supply

Iran holds large reserves of natural gas – and the proximity to the Middle East makes it a natural candidate for supply and interconnections.

Following the lifting of the sanctions, Iran is expected to become a major producer with significant potential for export. However, production is not easily increased and while oil export facilities already exist, natural gas export and production is less developed. The main prospect is the South Pars and the Kish field but even these will take some time to develop further. We expect the earliest significant increase to occur post 2020.

Figure 68: Production projection



Source: Ramboll

10.11.3 Gas Demand

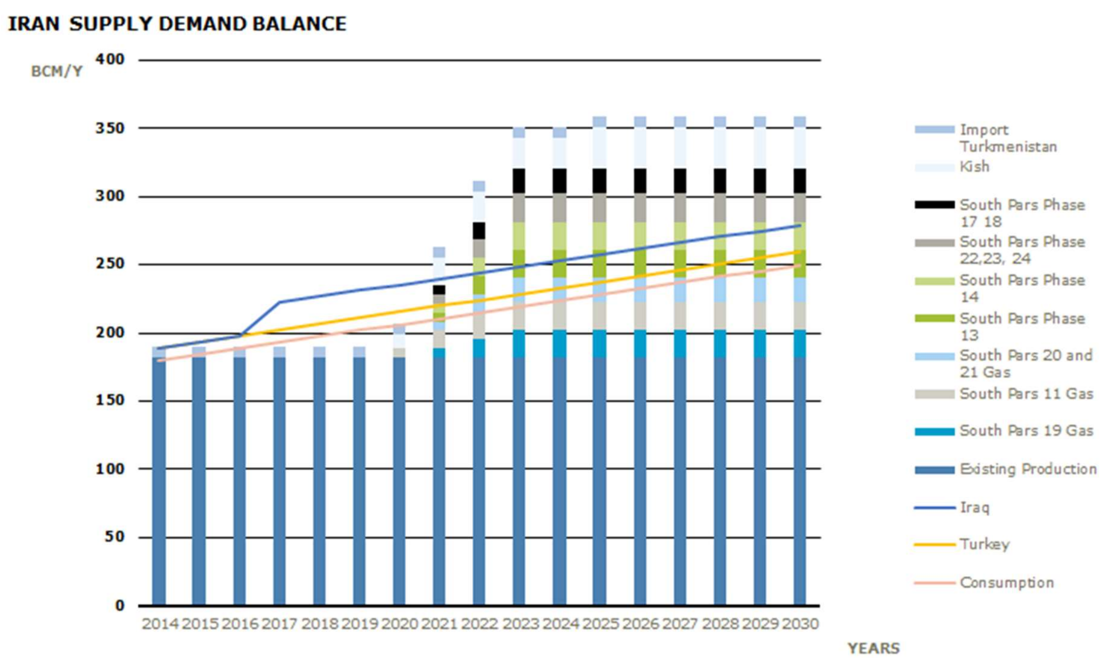
Iran is currently consuming up 180 bcm per year and relies on imports from Turkmenistan and Azerbaijan to meet demand in the northern part of the country. WoodMackenzie estimates that consumption could reach 190 bcm per year in 2025 and we believe that demand can increase

beyond as the population is increasing and will be 10 million higher in 2030 than today. Furthermore
Iran has the potential to export natural gas in the form of industrial products.
Therefore Iran would approach the same levels in terms of gas consumption per capita as Russia, corresponding to 250 bcm per year in 2030.

Because domestic consumption is seasonal, there is a possibility that internal bottlenecks could limit the amount of gas that can be brought to the market. For example, it is estimated by local authorities that the peak demand is around 608 mcm/d, with the power sector consuming 126 mcm/d, the industry 80 mcm/d and the residential sector 402 mcm/d on a peak day in January. These figures will only increase as economic activity increases and may be the reason why Iran is the sole holder of storage capacity in the region.

Additionally, commitments to both Turkey, Iraq and Pakistan have been made, implying that the current production is not covering the demand and export commitments until new phases of the South Pars enters into production. The gas balance below in Figure 69 is a result of the above assumptions. It should be noted that neither deliveries to Pakistan nor Iraq have commenced.

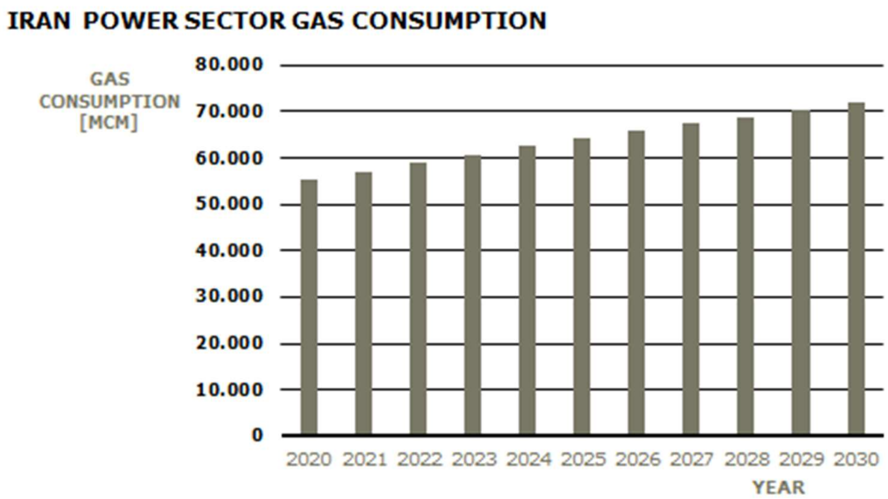
Figure 69: Gas balance Iran



Source: Ramboll

10.11.4 Power sector model outputs
Gas consumption in the power sector rises from just above 50 BCM in 2020 to 70 BCM in 2030 (see Figure 70 below). Today gas consumption is at maximum 45 bcm and probably even lower so the expansion in the power sector would be significant and demand some of the new production being brought online. The results show that demand may easily be higher than the 190 bcm estimated by WodMacKenzie.

Figure 70: Iran power sector gas consumption



Source: CESI

10.11.5 Infrastructure developments

Iran has the ambition to export gas both through pipelines and as LNG. As mentioned commitments have been made to both Turkey and Iraq, while Pakistan is yet to complete their part of the pipeline.

Due to the tight gas balance in the next 4 years we do not see any projects being viable before 2020, unless new gas resources can be made available quickly. Once the South Pars is up and running and the various phases are being developed there could be enough gas to accommodate more trade with the region and the rest of the World.

The following pipeline projects have been identified:

1) Driven by export facilities in Oman which will be idle from 2025. Oman is currently self-sufficient so the rationale behind a pipeline from Iran to Oman is to export the Iranian gas to the world LNG markets and perhaps even to India .

2) Iran – UAE, in the form of an offshore field in the Persian Gulf to UAE. Pricing disputes have stalled this project – supposedly the prices in the contract with Turkey serves as a benchmark for the Iranians, however these prices, do not reflect the current market situation and arbitration has taken place with the result oflower prices for Turkey and Botas.

3) Iran - Pakistan is under construction and could be operational within the next couple of years but construction on the Pakistani side is still not completed.

4) Iran-Kuwait.

5) Additional connections with Turkey – Iran is in talks with Turkey about potentially supplying gas for the domestic Turkish market. This will surely not occur until the price discussions have been resolved.

6) Iran is considering exports to Europe via Turkey as well – feeding into the TANAP pipeline. An estimated 5.1 billion USD investment[37] would be required internally to enhance the network from Assaluyeh in Iran to Bazargan at the Turkish border.

LNG export is also on the agenda in Iran. However, this is not something which we would expect in the short to medium term, although initial investments have been made to prepare the facility. It would make more sense to utilize the LNG export terminals in Oman as they could be idle.

Box 11: Iran – Oman Pipeline

Iran – Oman Pipeline
With capacity of up to 1.5 bcf/year, corresponding to around 15 bcm/year, the pipeline would have the possibility of fully supplying the LNG export terminals. Even nowsome capacity is idle in the terminal –this will only increase over the coming years and by 2025 Oman will abandon LNG export altogether. The pipeline has met several challenges along the way:Oman and Iran have not been able to conclude an agreement on the prices of transport and sale of gas in Oman. The project also faces significant opposition from neighbouring countries and as recentlyas late as October 2016, the routing of the pipeline had to be changed in order to avoid waters controlled by the UAE. This has increased the price of the project from 1 BUSD to 1.5 BUSD as much deeper water depths of up to 1.000 m need to be crossed.

On the other hand several other factors are in favour of the project. Apart from the idle LNG export capacity the project enjoys the attention of both Shell and Total who entered talks with the project promoters in November 2016. From an Iranian perspective Total is interesting as they have been chosen for assisting Iran with development of some of the phases of the South Pars Field. Total is the operator of the North Field in Qatar from 2018.

10.11.6 Valuation of gas and gas supply pricing

10.11.6.1 Supply of gas

All the phases of the South Pars with available information have been investigated the CAPEX and OPEX developments of all phases is equivalent of a breakeven at around 2 USD/MMBTU.

10.11.6.2 Internal valuation of gas

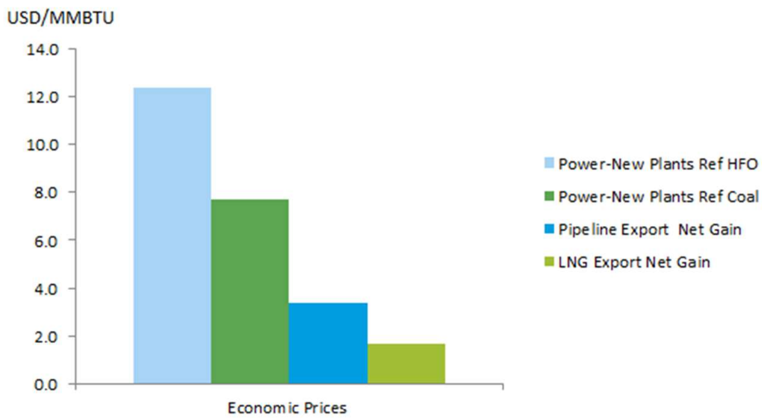
The high efficiency of CCGT plants above 50% offers a remarkable netback value in the usage of gas once compared to coal.

Considering a gas market price of 5 USD/MMBtu, the net gain from LNG export has been calculated based upon the following assumptions:

- Liquefaction CAPEX of 4 $bil and OPEX of 2% of CAPEX for a yearly LNG estimated capacity of 4.5 mtpa
- a WACC of 10%

[37] EIA

Figure 71: Internal netback values of gas -



Source: Ramboll

Another possibility is to export via pipeline to Europe via the TANAP on-shore pipeline towards a gas net gain value has been evaluated under the following cost assumptions:

- 943 kilometers long pipeline with an outer diameter of 48''and yearly capacity of 23 cbm
- CAPEX of 9 $ bil and a OPEX equal to 2% of the CAPEX
- 10% WACC

Based on these figures, the net gain from LNG gas export is equal to 1.65 USD/MMBtu, a value approximately 50% lower than the net gain of gas export via pipeline of 3.3 USD/MMBtu.

10.11.7 Subsidies

Iran experienced surging demand for petroleum products and other energy in early 2000s, selling gasoline at USUSD0.10 per litre, and launched the first phase of a targeted fuel subsidy reform program in December 2010, increasing domestic energy and agricultural prices by up to 20 times. The reform made Iran the first major energy-exporting country to drastically cut indirect subsidies and put in place an across-the-board cash transfer program for households. In the first phase of the reform, the authorities substantially increased the prices of all major petroleum products and natural gas as well as electricity. For details see Box 12.

Unit tariffs for natural gas were set using escalating schedules. Large household consumers were charged prices marginally higher than in international markets. Tariff schedules for natural gas were differentiated by quantity used and region.[38][39].

The consumption of subsidized petroleum products initially declined. Natural gas consumption continued to rise, but its growth significantly decelerated. But despite the initial positive response of demand to price changes, the growth in consumption of energy products rebounded in 2012 as energy prices remained unchanged, and inflation and nominal incomes rose[40].

[38] IMF : CASE STUDIES ON ENERGY SUBSIDY REFORM, Jan 28, 2013.

[39] IMF Working Paper Iran—The Chronicles of the Subsidy Reform

[40] IMF Subsidy Reform in the Middle East and North Africa , 2014.

Box 12: Iran's subsidy removal program[41]

As international oil prices approached USUSD150 per barrel and the FOB gasoline price was approximately around USUSD2 per litre, Iran's domestic price of USUSD0.10 per litre of gasoline was clearly unsustainable. Oil exports were declining while Iran was importing increasing amounts of gasoline to meet domestic demand and the relative price differential was fuelling smuggling to neighbouring countries.

Recognizing the severity of the problems, the authorities launched the first phase of a targeted fuel subsidy reform program in December 2010. The reform made Iran the first major energy-exporting country to drastically cut indirect subsidies and put in place an across-the-board cash transfer program for households. Despite an initial sharp increase in prices, gradual adjustment in prices was a key design feature of the reforms, which planned to increase domestic prices over a five-year period to 90 per cent of international prices. In the first phase of the reform, the authorities substantially increased the prices of all major petroleum products and natural gas as well as electricity, water, and bread.

In advance of the price adjustments, the authorities also deposited cash transfers in new bank accounts for households, which were to be financed by the revenue from price increases. About 80 per cent of the revenue from price increases was redistributed to households as bi-monthly cash transfers. The remaining balance of the revenue from price increases was to be set aside to provide support for enterprise restructuring with a view of reducing their energy intensity. The subsidy reform was also motivated by the authorities' broader structural reform agenda to foster growth and job creation more than to address fiscal concerns. Unlike other countries, Iran's reform was driven by a need to put its valuable hydrocarbon resources to more productive use rather than a need to reduce the direct burden of subsidies on the fiscal accounts. The Iranian authorities were clear from the outset that the main reform objective was to reduce waste and rationalize consumption.

Multitier tariffs on electricity, natural gas, and water were used to moderate the impact of the price increases on small users, mostly the poor. Unit tariffs on electricity, natural gas, and water use were set using escalating schedules. Large household consumers were charged prices marginally higher than in international markets.

The reform was preceded by an extensive public relations campaign to educate the population on the growing costs of low energy prices, and on the benefits expected from the reform. The authorities emphasized that the reform would benefit poor households, which would receive cash benefits.

Despite a good start at the end of 2010, the implementation of the reform program was suspended in late 2012 owing to growing concerns over its financing and the deteriorating macroeconomic situation. In mid-2012 the authorities postponed the implementation of the second phase of the reform because of lack of parliamentary support for the proposed cash transfer budget and implied price increases under the second phase.The initial success of the reform in driving down the consumption of subsidized energy and improving income distribution waned because of the sharp increase in inflation in the absence of supportive macroeconomic policies. The implementation of the reform program was suspended in late 2012 owing to growing concerns over its financing and the deteriorating macroeconomic situation. In mid-2012 the authorities postponed the implementation of the second phase of the reform. In 2015, domestic fuel prices were adjusted upwards by 20 to 40 percent and the deficit of the Targeted Subsidy Organization that administers the subsidies was eliminated in 2014/15

[41] IMF : CASE STUDIES ON ENERGY SUBSIDY REFORM, Jan 28, 2013.

The IEA estimates gas subsidies to be 22.3 BUSD for 2014 in Iran out of a total of 70 BUSD for all energy subsidies in the country. Iran accounts for 44% of all gas subsidies in the MENA countries.

The gas subsidy removal program was halted in 2012 and despite further increases, gas prices are below international market level. This could be a barrier for future investments in new exploration and gas trade by foreign investors if there is a risk the production is diverted to the domestic market. However, under Iran's 6th five-year development plan (2016-2021), the country plans an export of up to 80 bcm of natural gas of which up to 60 bcm will be sent to neighbouring countries (see section on Iraq)[42].

[42] Theiranproject.com, July 25, 2016

10.12 **Saudi Arabia**

10.12.1 Data and assumptions

Current marketed production is assumed to be declining by 2% throughout the period. The Fadhili and Wasit central processing facilities have been added.

To project demand we used the results from modelling the power sector. Since economic prices of gas are applied, Saudi Arabia will be importing electricity instead of generating it as it get too expensive to burn crude, at economic prices, in the power plants. Gas in the industrial sector is assumed to increase by 3% per year.

10.12.2 Gas Supply

Saudi Arabia is a special case in this analysis as it is not connected to the rest of the countries. Historically the oil sector had priority and gas was primarily a by-product from oil production. However, particularly during the past 5 years a change in policy with regards to gas has been observed:

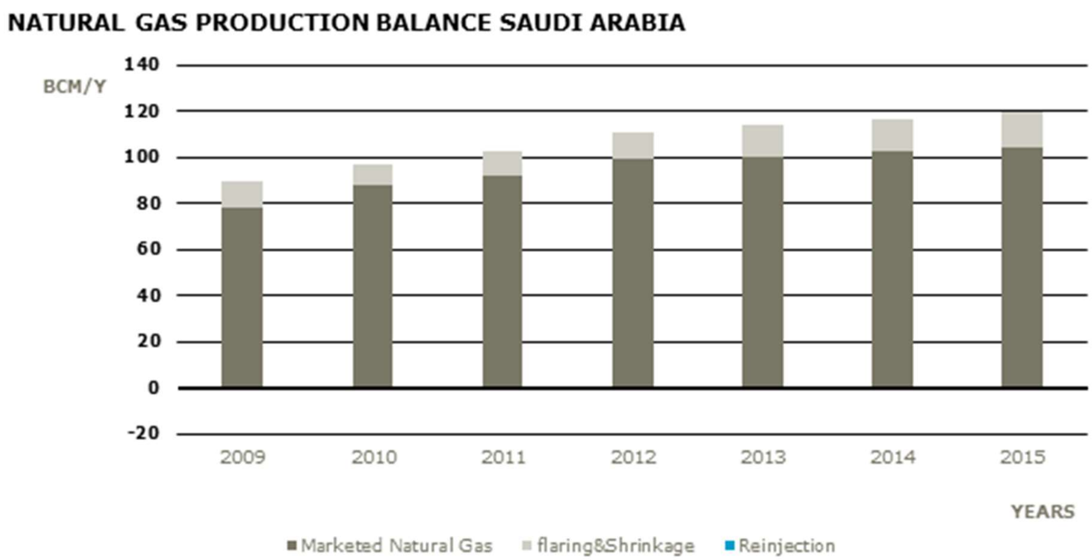
- Gas powered power plants are being constructed to replace old oil fired plants, ideally freeing oil for export.
- Previously Saudi Arabia was not interested in gas interconnections but in 2016 the Ministry of Energy indicated that this could be a possibility.
- Dedicated gas fields are being developed and new central processing plants such as the Fadhili and the Wasit will soon come online.
- It is a dedicated priority in the 2030 Vision to increase gas production capacity from 12 bcf/d today to 17.3 bcf/d in 2020 and 23 bcf/d in 2030. Since no export is planned this translates into a similar consumption.

This indicates that gas is definitely on the agenda and that large investments must take place in order to fulfil the ambitions. The move towards gas is underlined by Saudi Aramco stating that:

"Our maximum sustainable oil production capacity will continue to be maintained at 12 million bpd while we increase our gas production. Unconventional gas will make a significant contribution in our plans to increase gas production". Saudi Aramco.

Production has historically been rising from 80 bcm 2009 to 100 in 2015 and with this comes a relatively large increase in flaring. Some of this flaring could be reduced after the new processing facilities come online

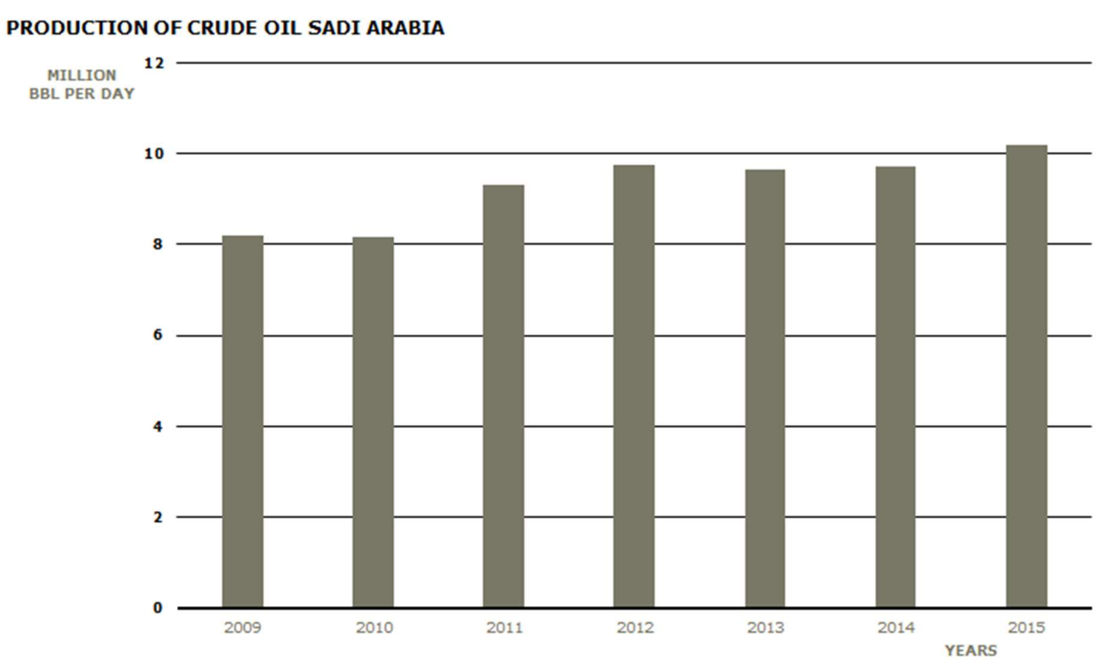
Figure 72: Gas Production Saudi Arabia



Source: OAPEC

Most gas production is associated with oil production. Below in Figure 73 the development in oil production is illustrated and there is clearly a strong correlation with gas production .

Figure 73: Production of crude oil Saudi Arabia



Source: OAPEC

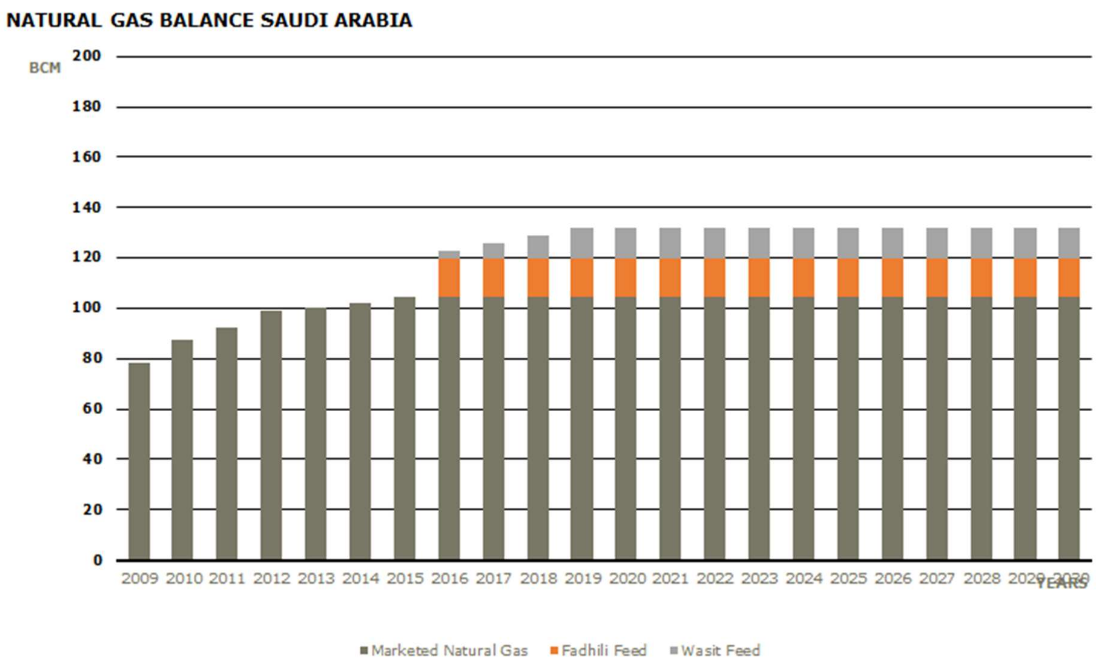
With the high degree of associated gas in the natural gas production, and bearing in mind that no further expansion of the crude oil production capacity is envisaged, it is clear that without new initiatives on the supply side, Saudi Arabia will have troubles meeting its ambitions of 23 bcf/d in 2030.

Looking ahead there seems to be different opinions on the development in production. While Saudi Arabia itself aims at increasing production to 17.3 bcf/d (177 bcm/y) in 2020 and 23 bcf/d in 2030 (235 bcm/y), the IEA estimates 100 bcm in 2020 and 127 bcm in 2030. To qualify this further, we examine the most recent projects announced and their expected production profiles.

New projects in the pipeline

Saudi Arabia is pursuing a number of new projects in order to reach targets for gas production and consumption, most notably the Wasit and Fadhili processing facilities that would enable the country to develop high sulphur fields. Below in Figure 74 the known fields connecting to these facilities have been added, taking into account that 20% of the gross production is lost in processing.

Figure 74: Marketed Natural Gas Production



Sources: Public information on capacity and start-up of fields

Given that the oil production will be maintained at the current levels of 9 to 10 Million barrels per day, we believe that the IEA prediction of 100 bcm in 2020 is too pessimistic. As illustrated above, the addition of the Wasit and Fadhili plants allows for the exploitation of new fields including offshore fields. In this projection we included the Hasbah (phase 1 +2) the Arabiyah and the Khursaniyah fields. However others may utilize the processing facilities in the future. The breakeven costs at the well head are estimated to be1.85 USD/MMBTU, relatively modest compared to other cases. However adding the expensive treatment at Wasit and Fadhili would increase this price. Quantifying the magnitude of the increase is complex as the facilities will enjoy other revenue streams from the sale of sulphur and gas supply to an integrated power plant, and connections from future fields. Thus, attributing the full cost of for example Fadhili to the well head price would be too conservative.

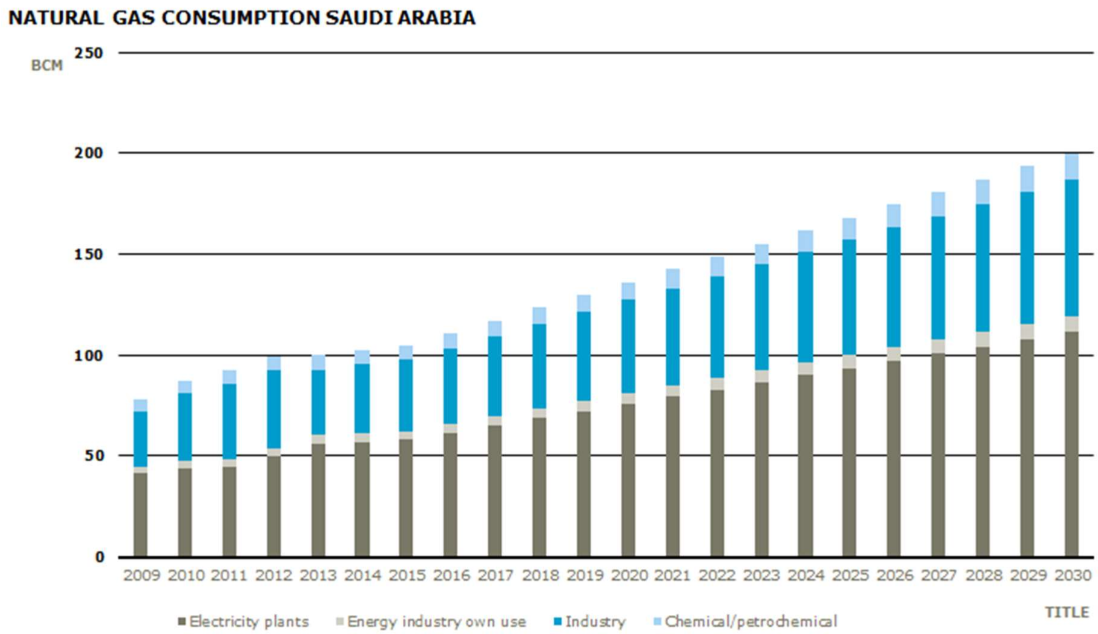
Finally, it should be remembered that Saudi Arabia doubled gas production capacity from 6 bcf/d in 2000 to 12 bcf/d in 2015 – so doubling from 2015 to 2030 is not impossible.

10.12.3 Gas Demand

Consumption in Saudi Arabia is expected to surge, mainly driven by the gas for power sector and the conversion of natural gas into high value products such as ethane and LPG which are also exported in large volumes. Additionally the petrochemical sector and desalination plants are consuming large amounts. It is envisioned that Saudi Arabia will consume up to 200 bcm in 2030 but such a massive amount perhaps not realistic. In the following we look into the consumption of gas in the various sectors.

Current consumption stands at just above 100 bcm. This is distributed in the following sectors: power plants, energy industry own use, industrial use, and chemical & petrochemical. Applying the distribution of consumption from 2014/2015 to 2030 to reach the total of 200 bcm provides the development illustrated below in Figure 75.

Figure 75: Estimated Natural Gas Consumption Saudi Arabia

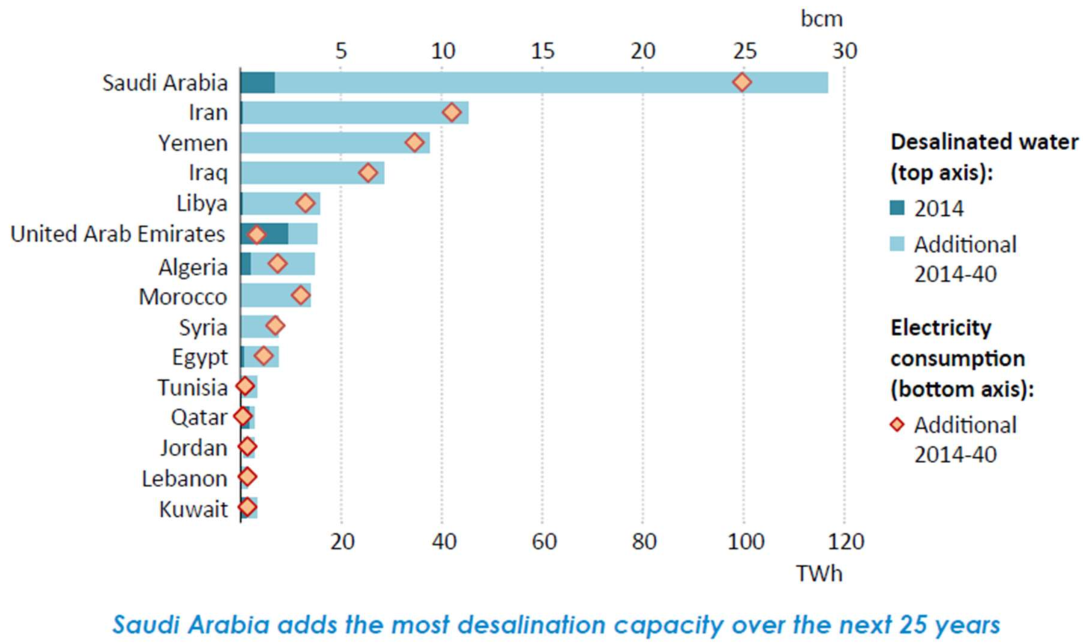


Source: IEA share, OAPEC total historical consumption,

Power Sector Consumption and Desalination

Saudi Arabia in particular will be adding a large amount of desalination over the coming years, as illustrated in the latest World Energy Outlook2016 Edition. In total, up to 100 TWh hours will be needed in order to accommodate the demand for water as illustrated below in Figure 76.

Figure 76: Desalination growth



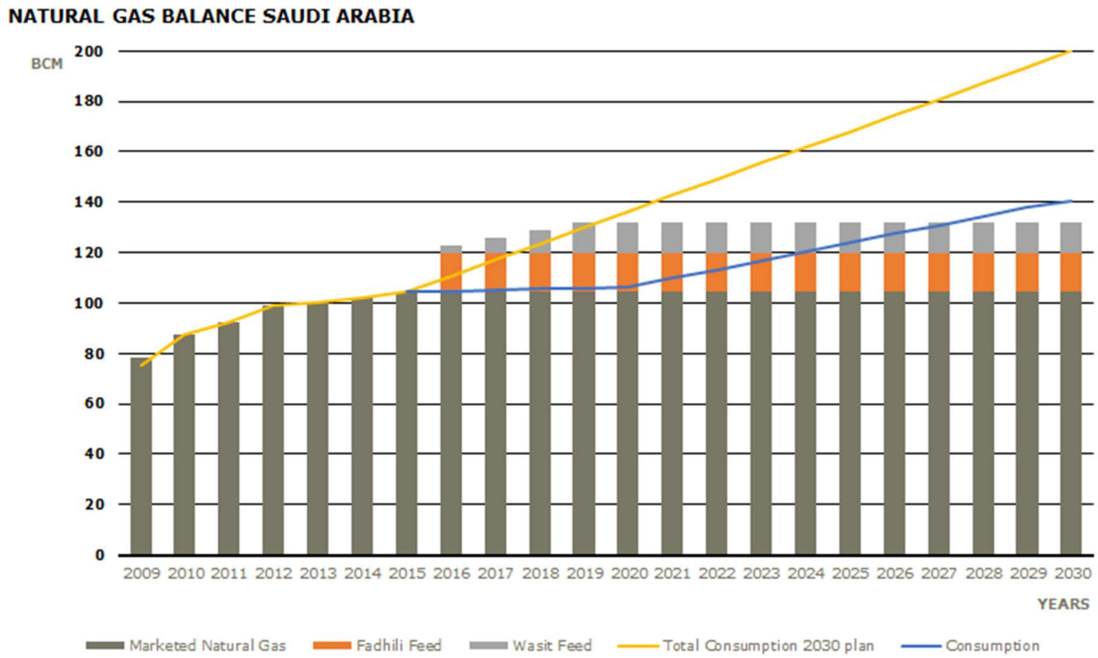
Source: WEO 2016

Conclusions availability of gas

The massive growth in desalination along with the growth in power production adds to the conclusion that demand is likely to outpace supply. The overall figures illustrated below combine current knowledge of production and consumption targets. The figure illustrates some extreme points. Firstly, we do not believe that t consumption in Saudi Arabia will reach levels as high as 200 bcm per year as this would require an exceptional increase of gas consumption in the power and industrial sector. Secondly, gas demand in the power sector in the PromedGrid is in this case, although theoretically correct, probably underestimated as Saudi Arabia would target more gas than 40-45 bcm/y in the power secor. What's more, due to its abundance, oil is not regarded from an economic point of view. Hence figure of somewhere (160 bcm) in between 200 bcm and 130 bcm may be the right outcome.

The supply is also likely to be larger than what is already known to come online. How much is of course uncertain, but keeping the production from known sources constant at their peak of 120-130 bcm a year would be a prudent assumption, given that Saudi Arabia is also investigating their shale resources. Thus the supply gap is realistically likely to be somewhere between around 30 bcm per year (160-130 bcm) in 2030. It should be noted that these high level estimates are subject to a high degree of uncertainty.

Figure 77: Natural Gas Balance Saudi Arabia



Source: Saudi Arabia vision 2030, OAPEX, Saudi Aramco.

Whether the consumption in 2030 is 140 or 150 bcm/y does not matter so much – especially if the vision of 2030 becomes a reality. The point is that if consumption continues to increase the case for start importing gas seems to be clear. This has been recognized by the Government which this year, through the Minister of Energy, indicated that import of gas could become a reality in the future[43]. As is the case in many other countries in the region Governments think of LNG terminals as the primary way of importing, this is the case for Saudi Arabia as well. However, import of gas from Qatar could be an alternative given that the gas would be available.

10.12.4 Valuation of gas and gas supply pricing

10.12.4.1 Supply of gas

10.12.4.2 Internal valuation of gas

Given the higher efficiency of CCGT compared to HFO fuelled power plant, the netback value of using gas in energy generation is above 10 USD/MMBtu taking both new or existing HFO power plants into consideration.

[43] http://interfaxenergy.com/gasdaily/article/20608/saudi-arabia-considers-importing-gas

Figure 78: Value of gas Saudi Arabia

Source: Ramboll

10.12.5 Subsidies
IEA estimates gas subsidies to be USD 8.3 B for 2014 in Saudi Arabia out of a total of USD 78.3 B for all energy subsidies. The IMF estimates minimal explicit energy subsidies for 2015 and subsidies due to pricing below the Benchmark to USD47.3 B, down from USD69.9 B in 2014[44].

Saudi Arabia initiated substantial energy price reforms in December 2015 and plans to gradually increase domestic prices further over the next five years. The government announced an increase in gasoline, electricity and water prices (ranging from a 10 percent to 134 percent increase) for businesses and households. Domestic prices however, are still well below international levels. Saudi Arabia plans to set up an executive committee to launch a national program to review and rationalize energy prices.[45][46].

Natural gas prices were also increased from USD0.75 to USD 1.25-USD1.50 per MMBTU. The price of higher-grade gasoline increased from USUSD0.16 to USUSD0.24 per litre, while regular gasoline increased from USUSD0.12 to USUSD0.20 per litre (40-45% of international level). Diesel prices increased from USUSD0.07 to USUSD0.12 per litre for the transportation sector and USUSD0.09 per litre for the industrial sector around (20-25% of international level). Electricity prices are around international levels (USD 0.10/KWh)[47].

A relatively unknown factor is the implementation of the National Transformation program in Saudi Arabia. Given the objectives for the gas sector, summarized in Box 13, there could be reasons to believe that either Saudi Arabia envisages: substantial increases in internal consumption, an interest in export, and/or security of supply concerns.

[44] IMF Energy Price Reforms in the GCC—What Can Be Learned From International Experiences? Nov. 2015.

[45] IMF: _IMF_Regional_Economic_Outlook_, Oct. 2016.
[46] Fossil Fuel Subsidy and Pricing Policies Recent Developing Country Experience Masami Kojima. Energy and Extractives Global Practice Group, World Bank, January 2016
[47] IMF: _IMF_Regional_Economic_Outlook_, Oct. 2016.

Box 13: Key points of relevance in the 2030 Vision for the Kingdom of Saudi Arabia

""Saudi Arabia's Vision 2030" encompasses—in a number of domains—strategic objectives, targets, outcome-oriented indicators and commitments that are to be achieved by the public, private, and non-profit sectors". Most ministries and governmental institutions in KSA have specific goals and objectives to achieve either in 2020 or 2030. Several of these objectives are relevant for this study, however the most relevant seems to be the fact that an increase in gas production capacity through development of the exploration and research activities is targeted (Strategic objective #11).

Specifically an increase from 12 to 17.8 billion standard cubic feet per day is envisaged in order to increase the volume of gas supplies.

Source: National Transformation Program 2020.

Saudi Arabia is currently not trading gas with other countries. The current large subsidies do put a strain on government budget, but do not pose a barrier to future trade.

10.13 **Qatar**

10.13.1 Data and assumptions

Marketed gas is fixed at the Moratorium level of 189 bcm per year until 2020. From 2020 it is assumed that the increase of 20 bcm/y from the southern part of the North field will enter the market. In 2025 we illustrate the effects from adding the remaining 50 bcm/y which the IEA estimate could materialize if the moratorium was lifted. We don’t know whether this will happen but the likelihood is higher now than one year ago.

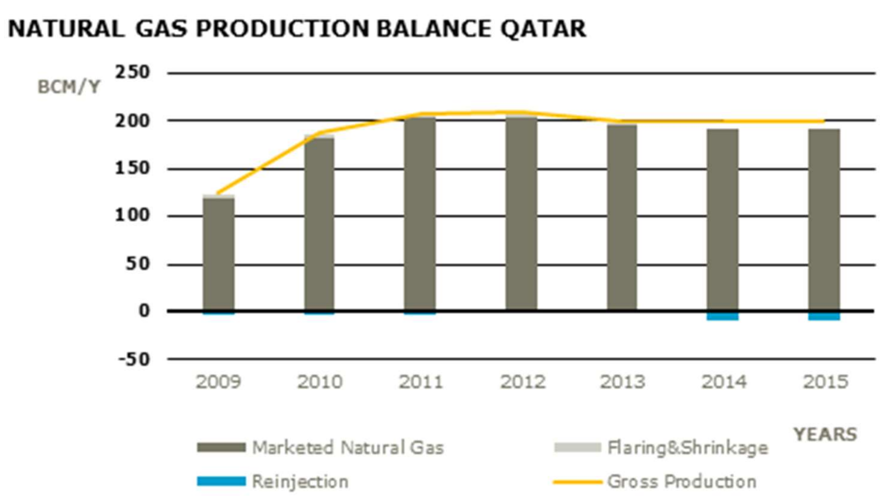
To project demand we used the results from modelling the power sector. Industrial and chemical production sectors have been assumed constant as we understood that the downstream segment will not receive additional investments. Gas in the energy industry (hereunder liquefaction) is assumed to decline 1% per year due to efficiency improvements. This may change, especially if Qatar choses to export the gas which was made available by lifting the moratorium.

OAPEC data is used for historic data. We have some doubts about the reinjection figures in 2015, 42 bcm,as it is unlikely that such large amounts have been reinjected and in our opinion this must be an error in the data. We truncated this to 8 bcm per year as in 2014. Additionally, according to the figures, flaring has been reduced to zero from 2 bcm in 2013. We regard this as a politically influenced figure and not a true picture of the reality.

10.13.2 Gas Supply

Gas production in Qatar is overwhelmingly dominated by the North Field, the largest non-associated gas field in the world. A moratorium established in 2005 is in place until April 2017 and this has restricted further production from the field.

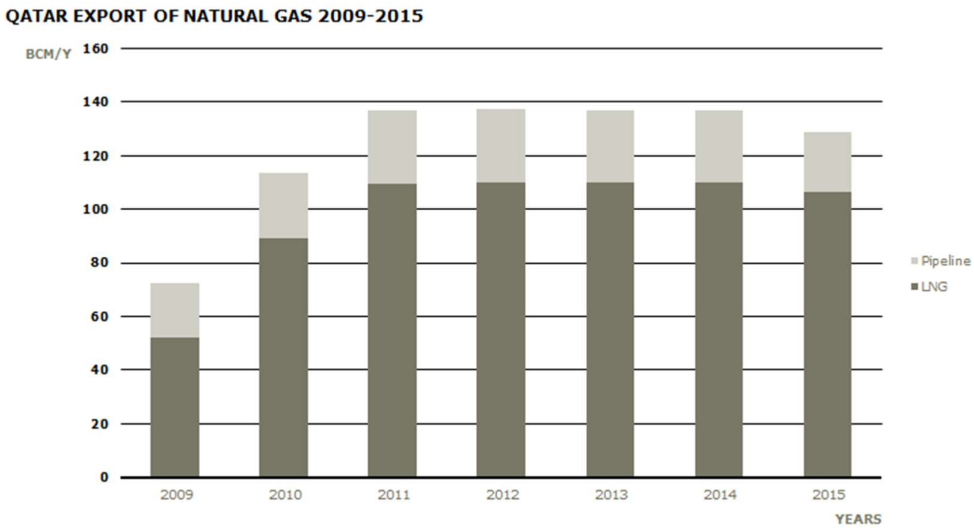
Figure 79: Natural Gas Production Balance Qatar



Source: OAPEC – adjusted figures for reinjection 2015

The data suggest increase export from 2012 to 2013 where sales of LNG surges from 110 bcm to 135 bcm. This seems unlikely given the moratorium and the actual production capacity. We corrected this to 110 bcm per year.

Figure 80: Qatar Export of Natural Gas 2009-2015



Source: OAPEC

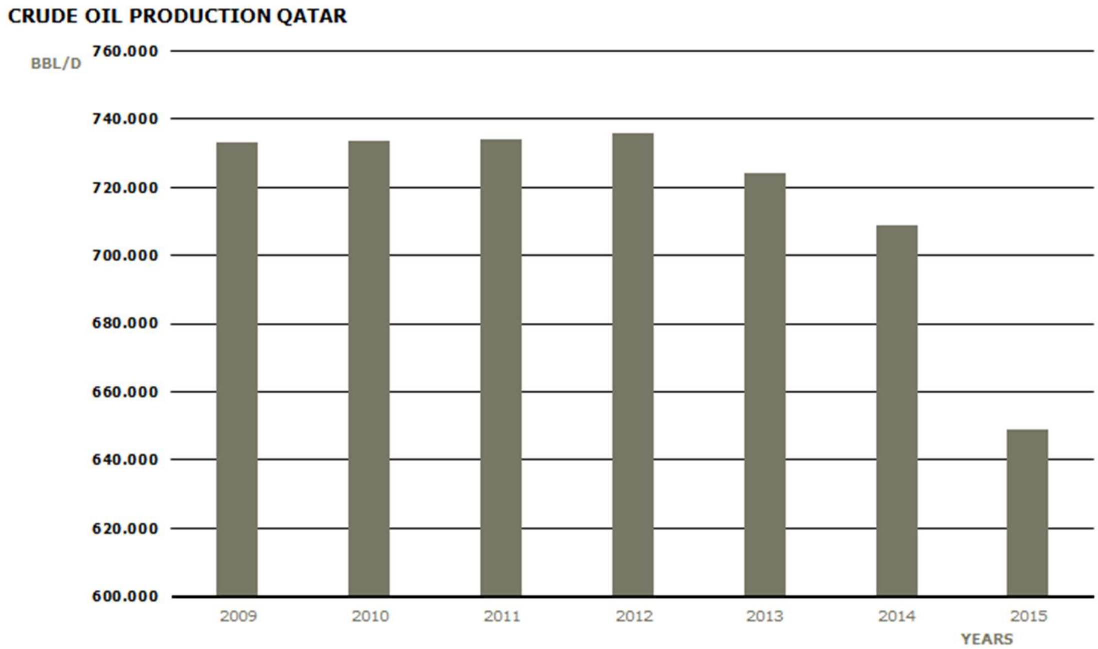
While Qatar is endowed with massive gas resources, oil resources are, although significant, nowhere near those of gas. Therefore to understand developments in the gas sector, it is informative to also bear in mind developments in in the oil sector.

Oil Production

Qatar has 25.1 billion barrels of oil reserves and produces from 10 operational fields, with only one, Dukhan, located onshore. However the age of the oil fields is now starting to become an issue. The onshore Dukhan field has been in operation since 1949, and has seen production decline to 230,000 of bopd from 300,000 bopd. The other two fields operated by Qatar Petroleum (QP), the offshore Maydan Mahzam and Bul Hanine, were brought on stream in the 1970s. All have experienced falling production in recent years.

Because of this, Qatar has embarked on a more aggressive EOR program since 2013, as the existing oil fields are in decline. The last major discovery in Qatar came in 1994 (the Al Rayyan field), and any supply growth in the short term is likely to come from increased output at Qatar's existing fields, particularly through the use of enhanced oil recovery (EOR) techniques. Operators have used EOR techniques in several fields, including Al-Shaheen, Dukhan, Bul Hanine, and Maydan Marzam. Crude oil production comes from just a few fields, led by Al Shaheen, Dukhan, and Idd al-Shargi which combined account for more than 85% of the country's crude oil production capacity. Qatar produced about 650,000 barrels a day of crude oil in 2015, declining from a peak of around 740.000 barrels per day in 2009-2012, a 13% drop within just 2 years.

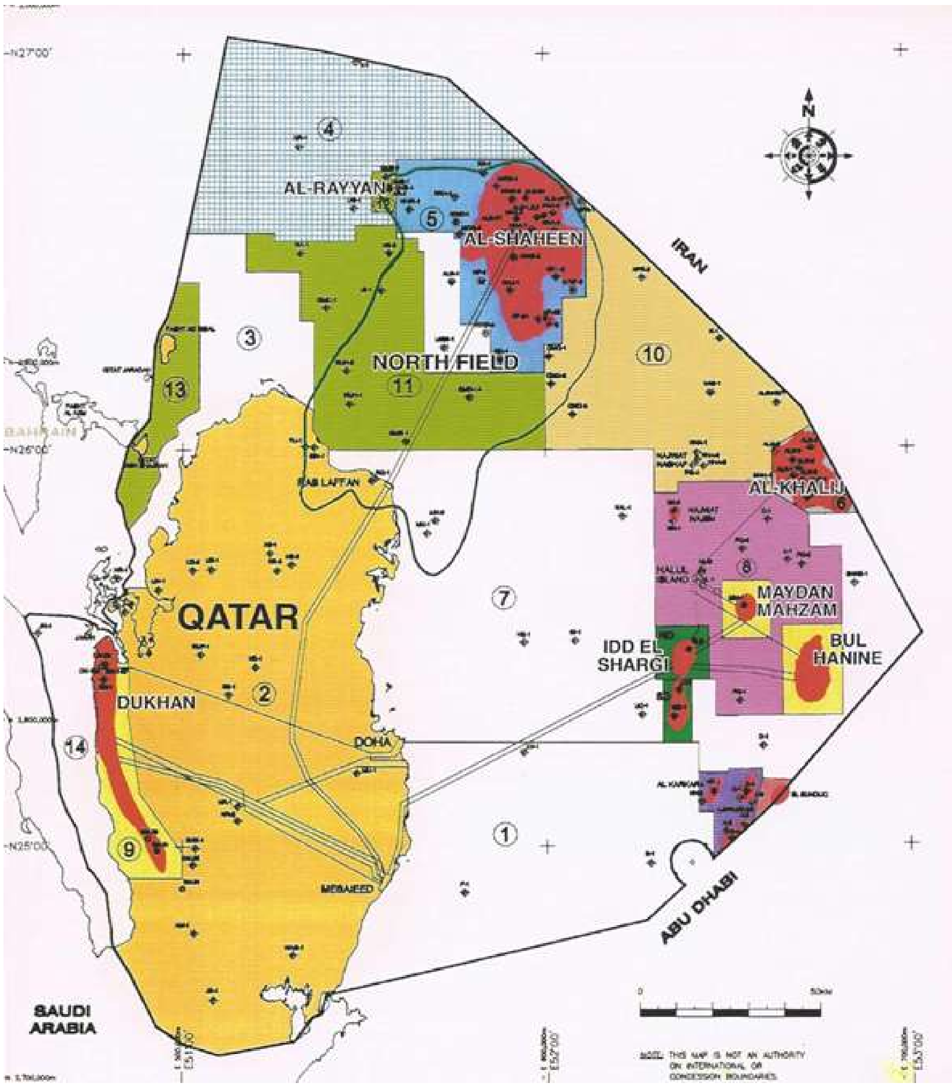
Figure 81: Crude oil production Qatar



Source: OAPEC

The most successful oil field is arguably Al-Shaheen, operated by Maersk Oil. The company has ramped up production from just 20,000 barrels per day in the mid-1990s, to about 300,000 barrels per day today, amounting to, 45% of Qatar's total oil output. Figure 82 below reveals the various fields and the associated infrastructure.

Figure 82: Map of Oil and Gas Fields Qatar



Natural gas developments

As mentioned, the North Field will see no further expansions, with the possible exception of the Barzan project, jointly developed by QP and Exxon Mobile. The project was the last to be sanctioned from the North Field in 2005, prior to the imposition of the moratorium. Barzan has been delayed for a year due to leaking pipelines. Specifically it is the upstream 40-48" pipeline which is leaking, despite being brand new. The leakage is thought to originate from the incorrect selection of materials which did not take into account the local conditions and the corrosive nature of the gas from the field. When online, the field is intended to make up for the natural decline in the North Field and function as a supply source for local demand. The price of Barzan is high, up to 10 BUSD, thus there is a possibility that the cost of production will be higher than the 2 USD/MMBTU which we originally estimated for the North Field.

We believe that Qatar may start to look into floating LNG production and that this may become a major initiative. Qatar is currently converting some of their Q-max ships to accommodate for this and in a practical sense, this would open up the possibilities for QP (Rasgas and Qatargas) globally, as they would not be restricted to the domestic gas resources. Additionally it confirms the decision to keep the moratorium in place. Floating LNG production could be beneficial for trade amongst the MENA and Qatar primarily.

Infrastructure
It is our impression that Iran is seen as a credible threat and could easily become an exporter of gas. The pipeline from Iran to Oman is a possibility. There are no indications that additional capacity in the Dolphin pipeline is underway. Currently the capacity is maxed out and if gas was to be delivered to UAE and Oman, a new pipeline would have to be constructed. A sub-sea connection to Bahrain is technically a possibility but has not to our knowledge been studied..

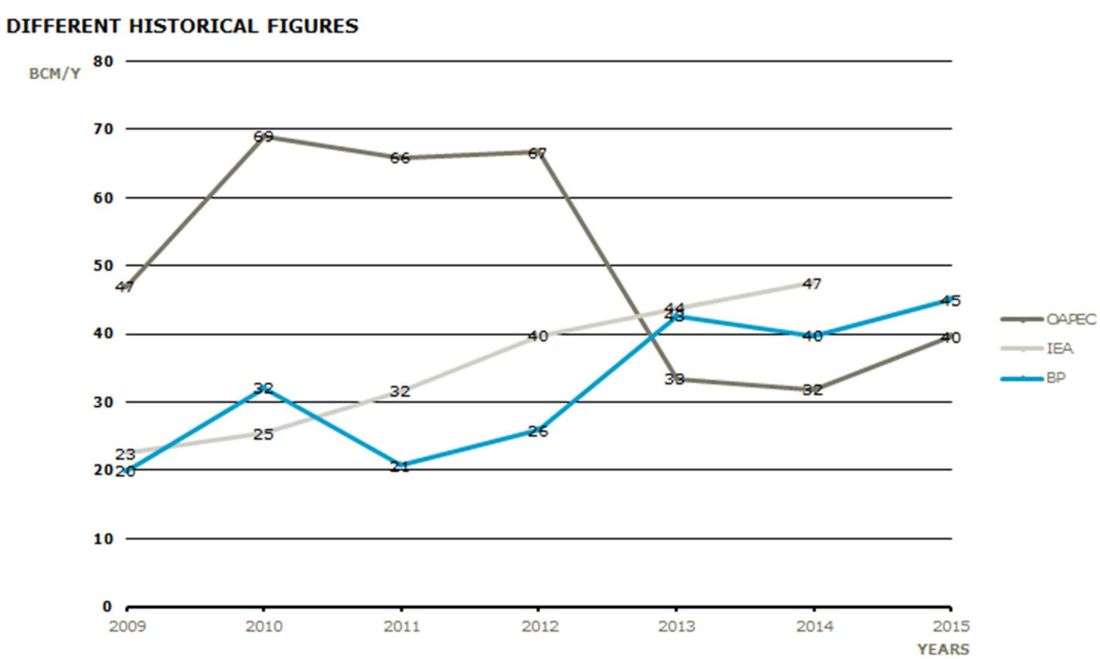
We believe that it could be in Qatars interest to import crude oil via pipeline or sea from Saudia Arabia, for example while supplying Saudi Arabia with natural gas (pipeline), in a swap deal - a quick win for both parties. Similarexamples have been seen internationally, such as the gas for power deal between Iran and Armenia. However, Qatar may not find it attractive to rely on Saudi for oil for security of supply reasons.

When it comes to expanding the horizon and options for production, several possibilities exist:

- Activities in other fields, such as Morocco and Egypt where QP has taken a position, could make sense for QP in order to diversify their production.
- FLNG could free up volumes in the North Field if supplied to existing customers and these volumes could in principle be used for regional trade. However for the business case to work they would have to increase net sales substantially to make up for the lower margins (arising from higher cost of production from FLNG). Additionally QP possesses a number of idle Q-max ships which could be converted to FLNG. So looking in the crystal ball there is a possibility that FLNG technology could free up gas resources specifically in Qatar for regional trade (provided that customers in the regional market pays the market prices).

10.13.3 Gas Demand
In comparison to the gas supply demand is a lot less transparent. Official statistics can be found from OAPEC, BP, and IEA, each showing sometimes very different figures for the individual years. See Figure 83 below.

Figure 83: Historical accounts of gas consumption in Qatar

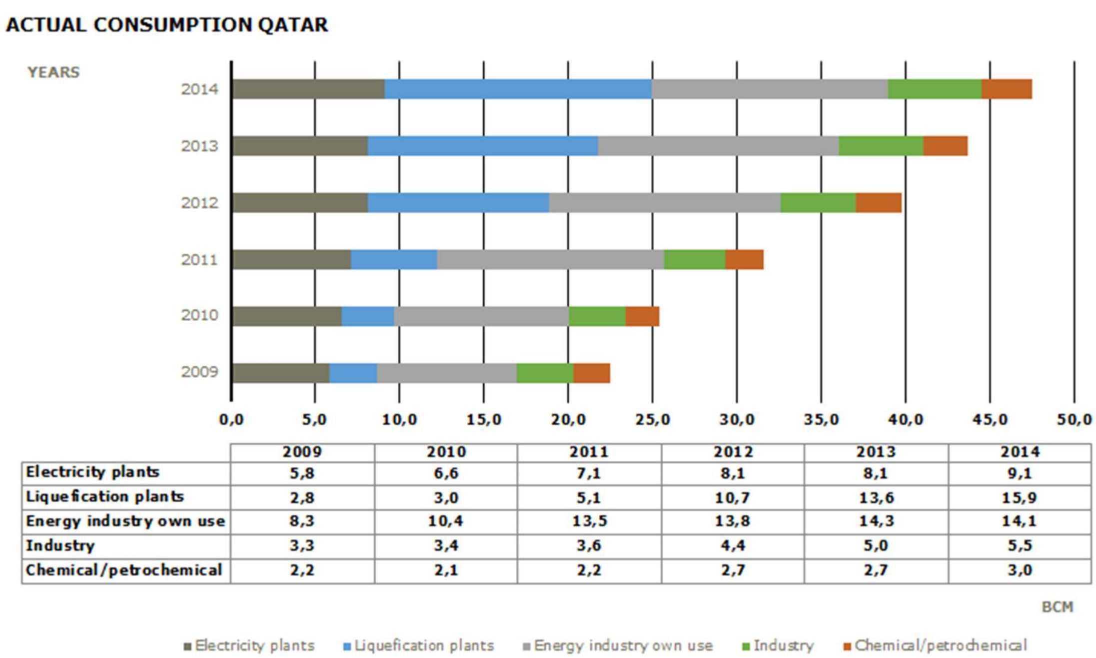


Source: IEA, BP, OAPEC

In our opinion the reason for this stems from differences in energy content, inclusion of gas in the liquefaction facilities and energy consumed on the platforms and at production sites. The huge drop from 2012 – 2013 indicates to us different approaches to measurements in OAPEC or Qatar. Thus for consistency reasons, we chose to go with the data from IEA which is almost consistently higher than the estimates from BP, and which makes I sense as these include the consumption from the liquefaction plants as well. Another advantage of this is that IEA delivers sector consumption as well.

The distribution of consumption developed is depicted in Figure 84. It is seen how gas in the liquefaction process has increased significantly over time with the additions of additional trains in Ras Laffan.

Figure 84: Actual consumption Qatar

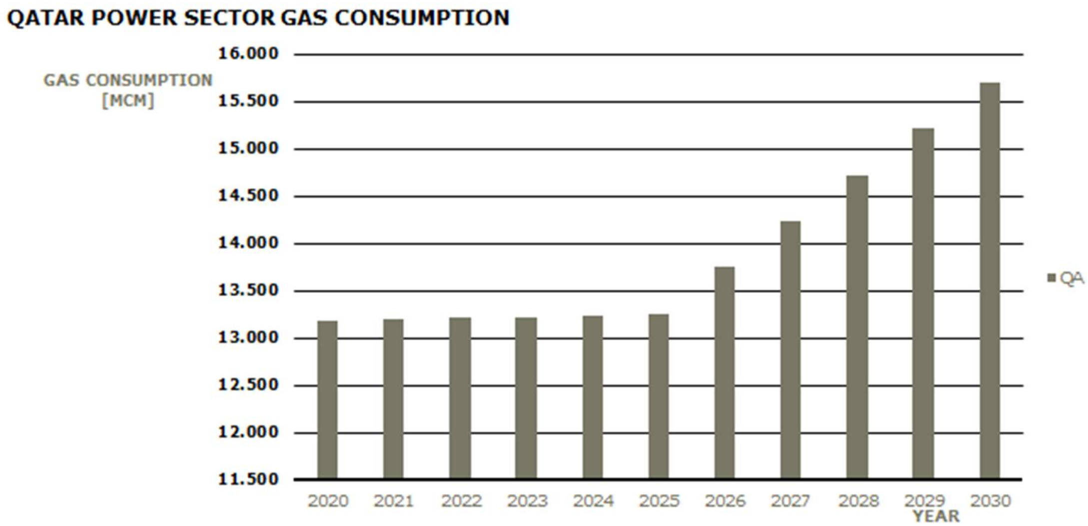


	2009	2010	2011	2012	2013	2014
Electricity plants	5,8	6,6	7,1	8,1	8,1	9,1
Liquefication plants	2,8	3,0	5,1	10,7	13,6	15,9
Energy industry own use	8,3	10,4	13,5	13,8	14,3	14,1
Industry	3,3	3,4	3,6	4,4	5,0	5,5
Chemical/petrochemical	2,2	2,1	2,2	2,7	2,7	3,0

Source: IEA

Future gas consumption is divided in the above sectors. The power sector is expected to increase while the other sectors are constant.

Figure 85: Qatar Power sector gas consumption



Source: Ramboll/CESI

Liquifaction plants

Given that the m,oratorium is in place, we do not foresee any increase in the gas consumed in the liquefaction of gas. In fact, due to the potential decline in export of gas and increase in domestic consumption andefficiency improvements, the consumption in this sector is expected to stagnate if not decline. In order to capture possible efficiency improvements we apply a factor of 1% reduction in gas consumption per year.

Energy industry own use

We assume that this covers the refining sector. A modest increase could be envisaged but no significant changes will occur here either. The same efficiency improvement as in the liquefaction has been applied.

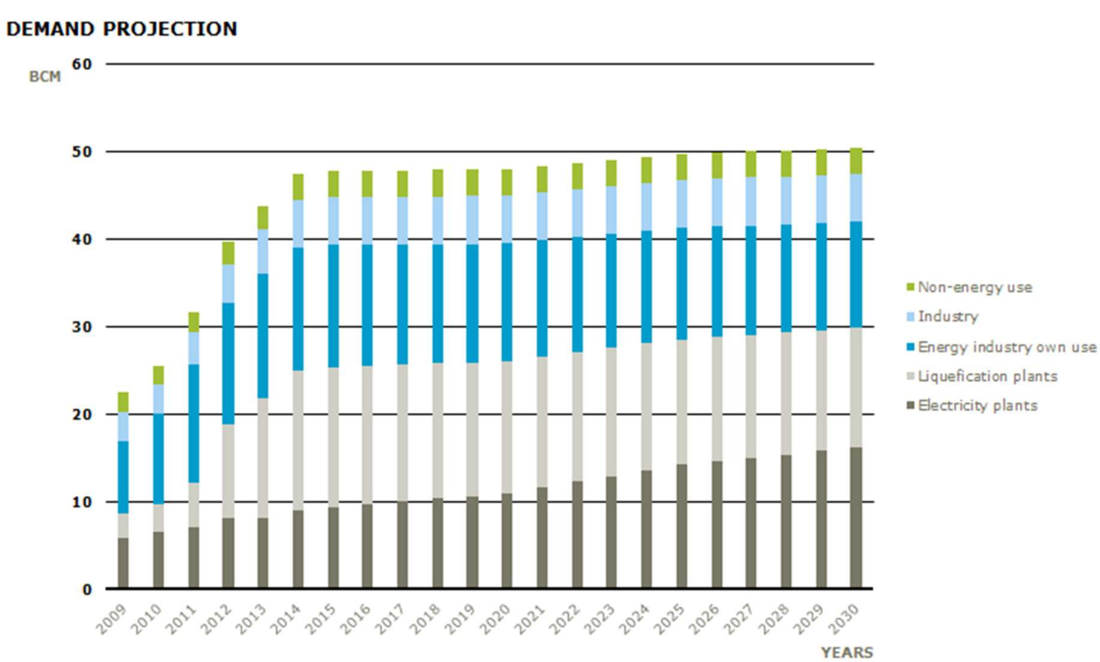
Industry

Downstream there are clear indications that no further investments will be made. This includes fertilizer, NGL, aluminium, plastic fabrication and all other petrochemical industries. This is a clear indication that value creation is seen in the upstream segment at the moment. As mentioned above, several crude oil projects are proposed, most notably the Bul Hanine and the expansion of the Al Shaheen field. For Al Shaheen it is our firm understanding that production of crude oil will be increased with up to 200,000 bbl/d. Total won the contract based on this promise and investment program. Bul Hanine is going ahead with a request for tenders – however the project is not yet finally sanctioned yet and the 12 Billion USD investmentcould be spent elsewhere in the current situation. Industrial use of gas is set to stabilise at the 2015 levels due to the freeze in downstream investments.

Petrochemical sector

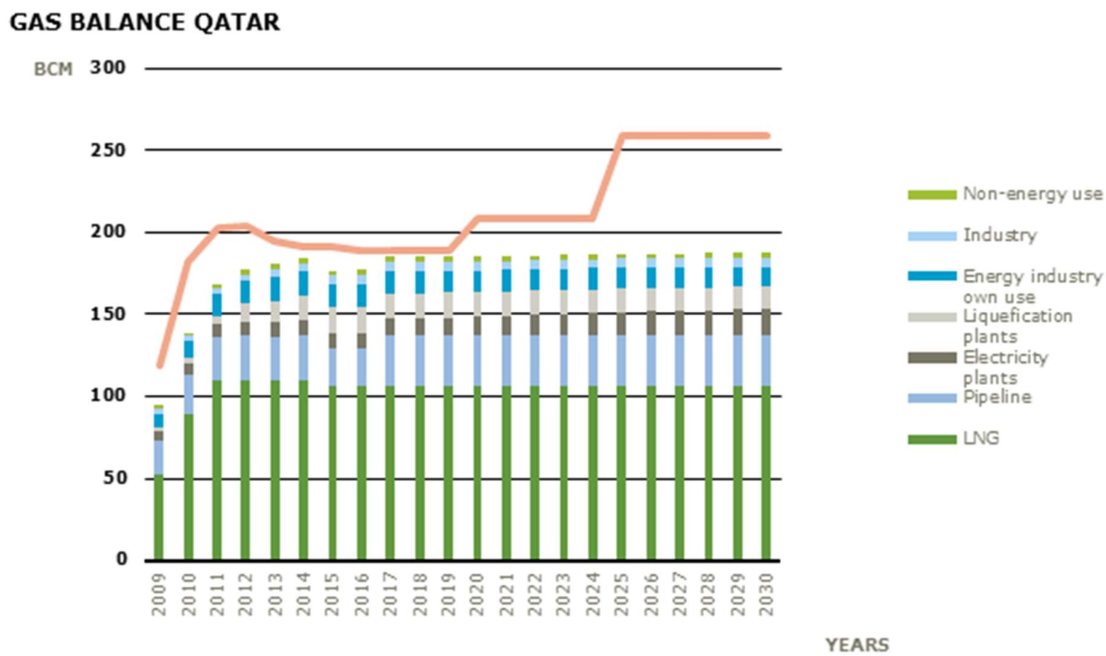
The indications are that no additional investments will be undertaken in Qatar, therfore we keep gas demand for this sector constant over the period. Overall we expect that gas demand in Qatar will most likely only increase in the power sector, where power will be produced for both internal use and for export to neighbouring countries.

Figure 86: Demand Projection Qatar



Combining the demand projection with the expected marketed gas from Qatar with the lifting of the moratorium shows by definition that up 70 bcm per year could be available from 2025.

Figure 87: Gas balance Qatar



Availability of gas for trade

Production

1) Estimates by IEA suggest that up to 70 bcm per year could be available post 2020 if the moratorium was lifted. Qatar decided to lift the moratorium with the addition of 20 bcm/y from 2020.
2) FLNG could be a game changer, if cost could be brought down, and deliveries to customers across the world from FLNG (or stakes in other liquefaction projects) could free up production in the North Field for neighbouring countries.

Consumption

1) gas and oil is prioritized for the world market and own consumption, for gas this is primarily the power sector
2) Qatar sees value creation in upstream projects and not downstream projects. Thus no further allocation gas for downstream projects should be expected.
3) Up to 8 bcm is used in the downstream industry and this would not increase in the future. Any declines could be utilized for trade.

Infrastructure

1) We would suggest that if the volumes could be made available to export gas to Saudi Arabia then they could export crude oil in the other direction.
2) With the announced expansion of the Dolphin Pipeline there is no more capacity available. If new capacity is to be brought online, a new pipeline parallel to the existing must be built.
3) Qatar could be contemplating investigating possibilities for gas storage in the old Dukan oil field. This would make good sense to meet peak demand.

A major game changer is the moratorium on gas production in Qatar. The moratorium has been in place since 2005 and restricts any new exploration development in the North Field. Qatar reaffirmed its commitment to the moratorium as recently as 2015. However several factors have most likely forced Qatar to revisit this decision:

- The lifting of the sanctions in Iran – this would in all likelihood enable Iran to start developing its part of the field. This could start a race for production between Iran and Qatar. On the other hand, both countries have a long-term interest in preserving the integrity of the reservoir.
- Sustained low oil and gas prices. Government budgets are presumably pressed, although substantial funds have been saved in various funds and increased volumes could help maintain the revenue.
- Geopolitical tensions. It is well known that Iran has ambitions to export from the region and to deliver gas to countries such as Oman. For Oman in particular it would be quite possible that the gas received would be allocated for export through the LNG export terminal which is running out of supply. The recent decision to utilize the option to increase the export through the current Dolphin pipeline could be seen as an attempt from Qatar to gain the upper hand.

If the moratorium is lifted and volumes become available there are a number of possibilities for export of the gas:

- Increasing LNG export capacity. With the current outlook for the LNG market and the potential for oversupply created by the US and Australian LNG export facilities coming online soon in 2016-2020, we do not believe that this will be a possibility which will be pursued. Previously it was shown that the profitability of Greenfield LNG export facilities in terms of the return on investment would in most cases not be high enough to motivate new LNG export.
- Export of gas as feedstock. Over the past years several projects relying on gas for feedstock have been shelved. Originally the gas to be produced from the Barzan project was destined for this sector. However it is now being used for internal power production and desalination projects to meet the internal demand for gas.
- Export of gas through pipelines. Pipelines are often a cheaper and more efficient way of transporting gas. The lifting of the moratorium would imply that there are more export pipeline possibilities between Qatar and the surrounding countries and regions. This could lead to Dolphin 2 or 3.
- A barrier for pipelines from Qatar to Egypt is Saudi Arabia, but Saudi Arabia itself may have an interest in receiving Qatari gas.

In the following we present the available options for pipeline export from Qatar -a large-scale pipeline export out of Qatar overview:

- 2A: Route to Turkey: Onshore Saudi Arabia, Kuwait, Iraq, Turkey
- 2B: Route to Turkey: Offshore, Kuwait, Iraq, Turkey
- 2C: Route to Egypt: Onshore, Saudi Arabia
- 2D: Route to Arab Gas Pipeline: Onshore Qatar, Saudi Arabia, Jordan

2A Onshore Saudi Arabia, Kuwait, Iraq, Turkey

A pipeline connection could be established from Qatar to Turkey by first deviating the pipeline from route 'M' at the point of Al Rumaila in Iraq. The entire pipeline route would consist of the following sections:

Section	Description	Length km
N	Qatar to Turkey via Iraq (1.974 km)	

Turkish border to Baiji pipeline (291 km)	190
Baiji to An Nasiriyah pipelines (553 km)	N/A
Al Rumaila to An Nasiriyah pipelines (127 km)	127
Kuwait City to Al Rumaila, Iraq (171 km)	N/A
Ras Laffan to Kuwait City (832 km)	832

* Assumed constructed

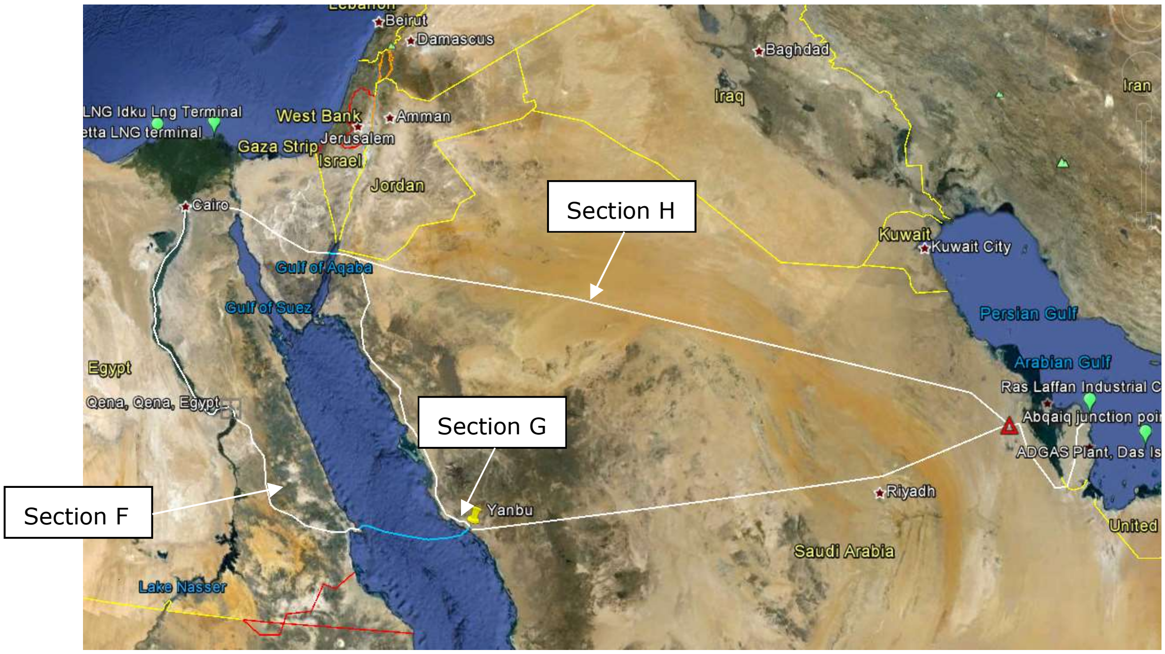
Figure 88: Onshore Saudi Arabia, Kuwait, Iraq, Turkey

2.B – onshore from Qatar to Cairo

Three different pipeline routes have been investigated:

F. Ras Lafan, Qatar, to Cairo, Egypt, via Abqaiq and Yanbu, Saudi Arabia, Red Sea crossing, through the Nile Vally to Cairo (2874 km)
G. Ras Laffan, Qatar, to Cairo, Egypt, via to Yanbu, Aqaba and Sinai (2679 km)
H. Ras Laffan, Qatar, to Cairo, Egypt, via offshore Aqaba and Sinai (2281 km)

Figure 89: Route options of major transmission pipelines, Qatar to Egypt



The pipeline sections are indicated below:

Section	Description	Length km
F	Qatar to Egypt via offshore Yanbu (2.874 km)	2874
	Cairo to Asyut, Egypt (357 km)	N/A
	Asyut to Qena, Egypt (223 km)	223
	Qena to offshore Egypt (458 km)	458
	Yanbu, Saudi Arabia, to offshore Egypt (258 km)	258
	Ras Laffan to Yanbu (1578 km)	1578
G	Ras Laffan to Yanbu, Aqaba and Cairo (2679 km)	2679
	Ras Laffan to Aqaba via Yanbu (2302 km) Offshore Aqaba (20 km)	2302
	Offshore Aqaba to Cairo (357 km)	20
		357
H	Qatar to Egypt via offshore Aqaba (2.281 km)	2281
	Ras Laffan to Aqabau (1904 km)	1904
	Offshore Aqaba (20 km)	20
	Offshore Aqaba to Cairo (357 km)	357

* Assumed constructed and in service

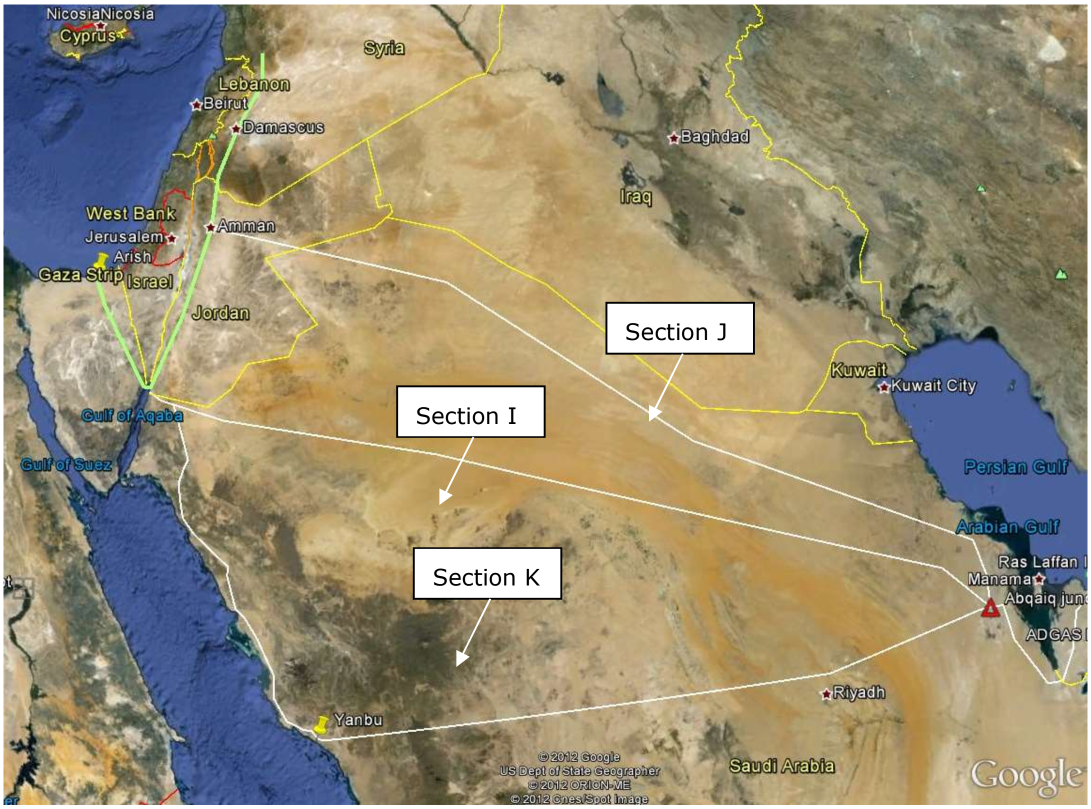
2C Qatar Arab Gas Pipeline

Natural gas could likewise be transhipped from the gas rich Qatar to link up with the Arab Gas Pipeline (AGP) in Jordan. The routes considered are:

F. Ras Laffan to Aqabau (1904 km)
G. Ras Laffan to Amman (1943 km)
H. Ras Laffan to Yanbu and Aqaba (2302 km)

Section	Description	Length km
I	Ras Laffan to Aqabau	1904
J	Ras Laffan to Amman	1943
K	Ras Laffan to Yanbu and Aqaba	2302

Figure 90: Route options major gas transmission pipeline, Qatar to Arab Gas Pipeline.



10.13.4 Valuation of gas and gas supply pricing

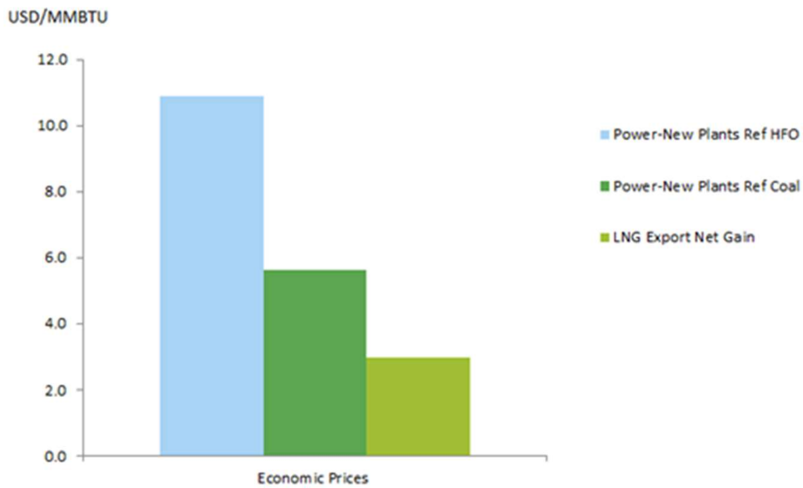
10.13.4.1 Supply of gas

There is no doubt that the current costs of production are very low, most likely in the range of 0.25 – 0.50 USD/MMBTU. Looking ahead, only 1 additional field, the Barzan field, will materialize over the studied period. Given the known Capex and Opex we estimate this to be around 3 USD/MMBTU. This could beat the high-end of the scale and should be regarded as an upper bound.

10.13.5 Internal valuation of gas

Qatar's primary source of energy is gas which employed in both CCGT and OCGT plants. The value of gas in LNG export is estimated to be 3 USD/MMBtu if capital costs for the LNG cycle are assumed as "sunk".

Figure 91: Value of gas Qatar



Source: Ramboll

10.13.6 Subsidies

Domestic gas is supplied as fuel and feedstock to power plants, petrochemicals and industries across Qatar. The price is set at 0.75 per MMBTU. Qatar is the largest consumer of energy on a per capita basis.[48]

IEA estimates gas subsidies to be USD 1.6 B for 2014 in Qatar out of a total of USD 6.2 B for all energy subsidies. IMF estimates explicit energy subsidies for 2015 of B 1.2 B, and subsidies due to pricing below Benchmark to USD 7.7 B, down from USD 10.6 B in 2014.

Qatar raised pump prices for gasoline by 25 percent and diesel by 30 percent in January 2011. Diesel prices were raised again in May 2014 by 50 percent. Water and electricity prices were raised and tiered according to consumption in October 2015. In January 2016, gasoline prices were increased again by 30 percent. The government has set up a committee that makes recommendations on whether prices should be adjusted, based on global markets and regional developments, and prices were increased again slightly by 4 percent in August 2016[49], reaching 70-85% of the international benchmark.

The low domestic gas price has not proved to be a barrier to developing gas exports and Qatar has become the largest LNG exporter in the world.

[48] BP Statistical Energy Review. 2016

[49] IMF_Regional_Economic_Outlook_, Oct. 2016.

10.14 **Egypt**

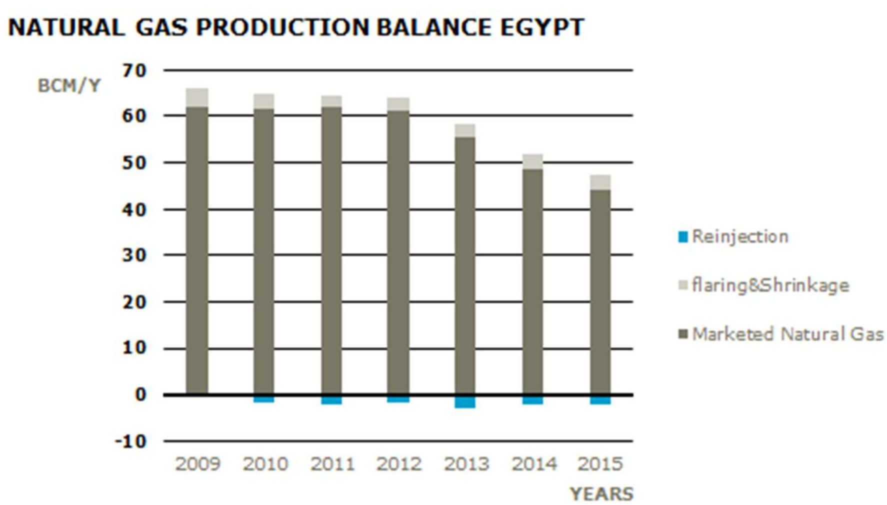
10.14.1 Data and assumptions

OAPEC data has been used for historic data and it is in line with our expectations. Existing production has been falling, and we assume a 5% annual depletion rate for the rest of the period. A number of new fields have been identified. These fields are added to the production. Demand in the power sector is estimated by the power market simulator. Industrial demand is assumed increasing by 3% per year.

10.14.2 Gas Supply

Egypt is one of the most important countries for the study. It is a link between North Africa and the Middle East and is a potential regional hub for gas flows as it has one of the largest gas markets in the region. According to BP 2015, it has 77 tcf of natural gas reserves and produced 1.8tcf of natural gas per annum. Similar numbers are quoted by OAPEC. The development in the gas production balance in Egypt is dominated by the decline in the production observed from 2009 to 2015.

Figure 92: Natural Gas Production Balance Egypt



Source: OAPEC

Several explanations for declining production exist: political instability, lack of security, lack of investments in production and the fact that several large consumers have not been able to pay for their consumption. This has in turn led to disincentives for producers as they risk not getting paid. The government still owes substantial amounts to producers.

10.14.3 Future fields and production

As production declined the government made a decision to import LNG and gas from Israeli fields. In 2014, ENI discovered the Zohr field in offshore Egypt. The Zohr field is expected to have almost 30tcf of gas reserves and can produce up to 0.99tcf or around 30 bcm of gas per year. A number of other fields have reached advanced stages Box 14 summarises the fields investigated and included in the supply projections. .

Box 14: Fields investigated in the supply projections

Zohr (Shorouk block) A super giant, in a new play, located in a mature area and close to existing facilities. Estimated 850 bcm in place, 1500 meters of water depth.

Satis (North El Burg)
North El Burg is located in the central part of the Nile Delta. The concession covers 483 square miles (1250 square kilometres) of shallow water ranging from 197 to 328 feet (60 to 100 metres) deep.

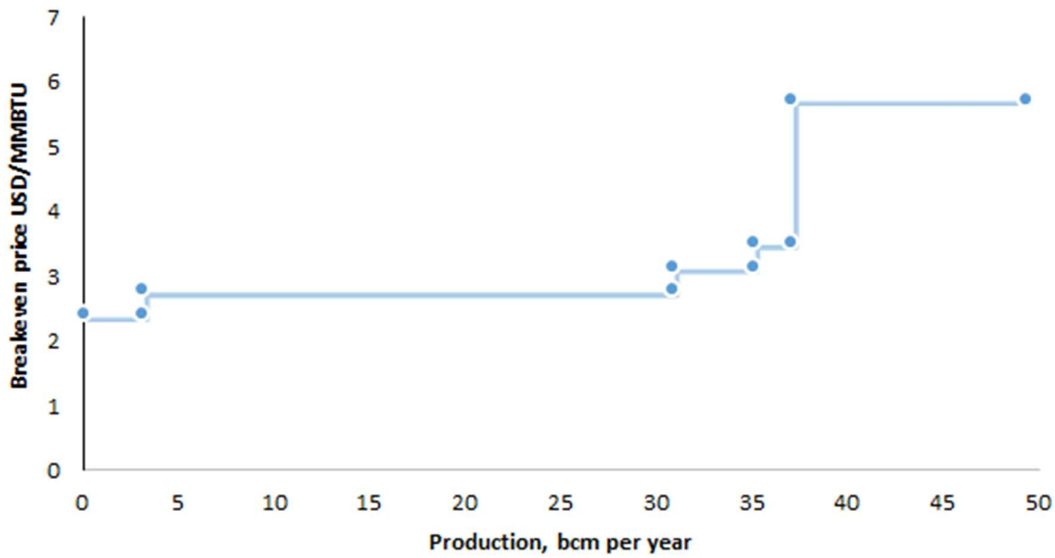
Nooros (Greater Noroos Area)
Nooros, Abu Madi West concession in the Nile Delta, about 120km northeast of Alexandria.

West Nile Delta domestic (Taurus/Libra, Giza/Fayoum/Raven)
The West Nile Delta (WND) Project involves the development of gas and condensate fields located within the North Alexandria (N Alex) and West Mediterranean Deepwater concessions in the Mediterranean sea, approximately 65km to 85km off the coast of Alexandria, Egypt.

Atoll Phase I (North Damietta conc,)
Deep-water field in the North Damietta Offshore concession. Water depths of 923 metres

To understand the likelihood of these projects depends on the individual breakeven prices. Below the fields are illustrated showing breakeven prices of 6 USD/MMBTU can be realized.

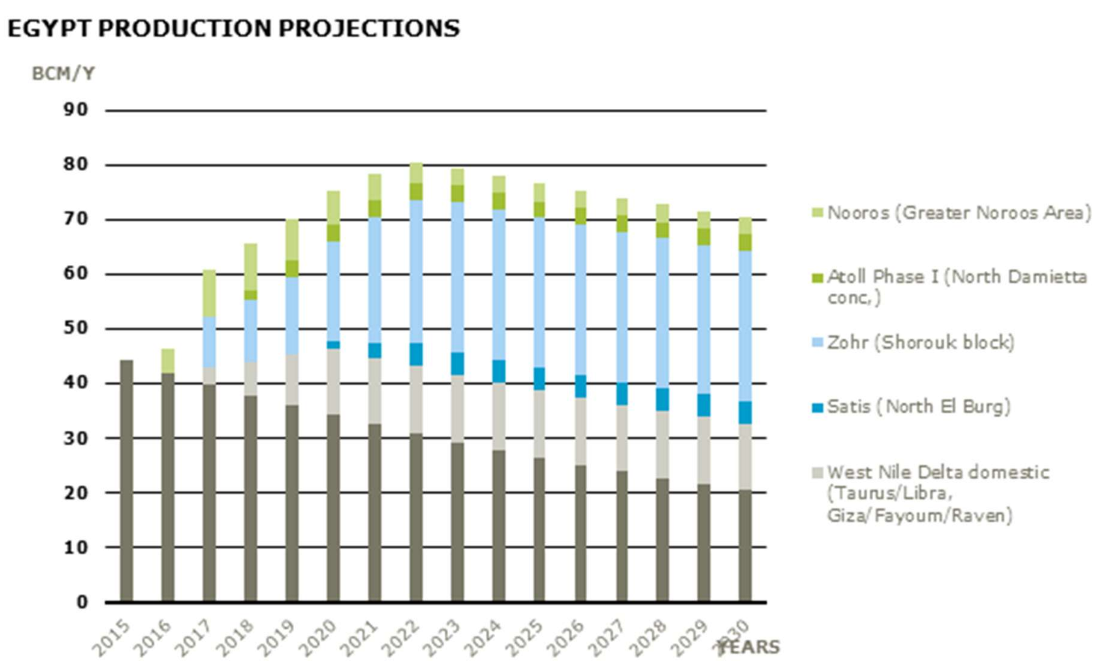
Figure 93: Breakeven price of 5 selected new fields in Egypt



Sources:Annual accounts, CAPEX, OPEX

Given that the production decrease of 5% per annum is continuing adding the 5 investigated fields could reach 80 bcm per year see Figure 94.

Figure 94: Potential future production key fields



Source: Own production profile and company data

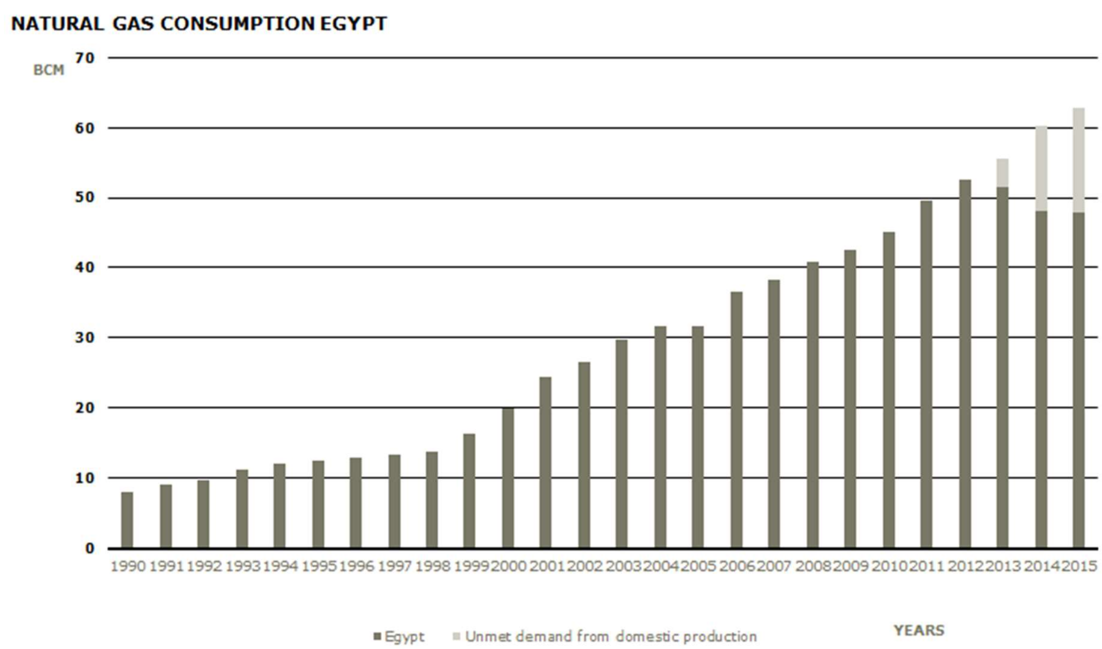
Imports

From being an exporter of LNG, Egypt currently imports LNG to address domestic demand. In the face of acute gas shortages and growing power outages, the government began diverting gas produced by foreign companies to the domestic market and by 2014, gas exports had all but ceased. BP declared force majeure in January 2014 for failing to meet its export commitments. These development eroded investor confidence in upstream oil and gas, turning Egypt into an importer of LNG in 2015[50][51]. In the following we investigate whether this is supply is sufficient to meet the future potential demand.

10.14.4 Gas demand

Gas demand in Egypt is divided on many different sectors including cement, iron and steelteel, fertilizer, petrochem, methanol, CNG, domestic and power. Total consumption has increased rapidly in the past 10 years – only to stall in the last 3 years due to unavailability of gas and reforms. Minor amounts have been imported but the fact remains that if this trend continues Egypt will face a consumption of approximately 100 bcm per year in 2020. The potential unmet demand (if Egypt had followed the trend from the past 8 years) is illustrated below.

Figure 95: Natural Gas Consumption Egypt and Unmet Demand



Source: BP and own calculations

There are several reasons to believe that consumption will not follow an ever increasing trend for a sustained period of time. Much of the historic increase has been attributed to the fact that gas prices were subsidized for almost the entire population. As previously discussed this did not incentivise additional investments in production and supply fell only to be partly supplemented by LNG.

Future demand could in our opinion be curbed by several developments:

- Pricing reforms. The closer prices are brought to prices which reflect the actual cost and value of gas ("market" prices) the less will be demanded by the market. The ongoing reforms have sought to protect the social consumers (such as the domestic market and

[50] [50] Egypt's Recent Subsidy Reforms, Kieran Clarke, IISD-GSI

[51] Jordan Times March 29, 2016

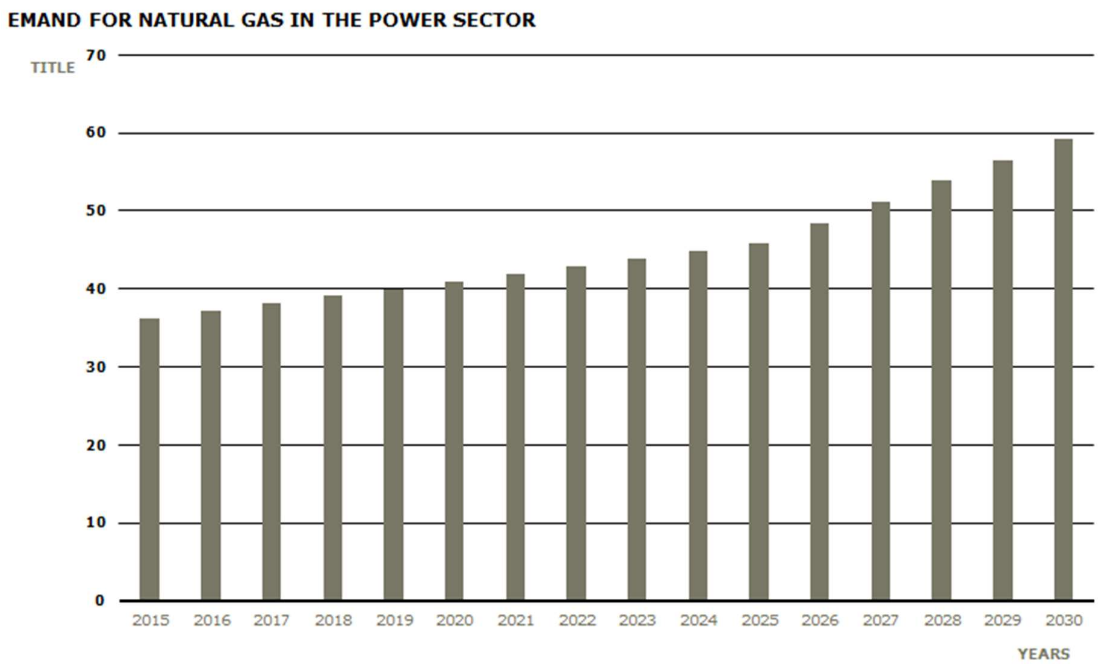
the power sector), from exposure to market prices. For industrial sectors, such as cement and fertilizer it is our understanding that prices are set according to market benchmarks.

- Increased efficiency in power generation. Currently a number of high efficiency plants are planned including the on 3 x 4,800 MW combined cycle power plants at Burullus, New Capital and Beni Suef and the Assiut and West Damietta CCGT Power Plant Extensions.

10.14.5 Power sector

The future demand for gas in the power sector is illustrated below in Figure 96. Our results indicate an increase from 40 bcm in 2020 to 60 bcm in 2030, almost equivalent to the total current consumption of Egypt 2015.

Figure 96: Egypt power sector gas consumption with economic prices



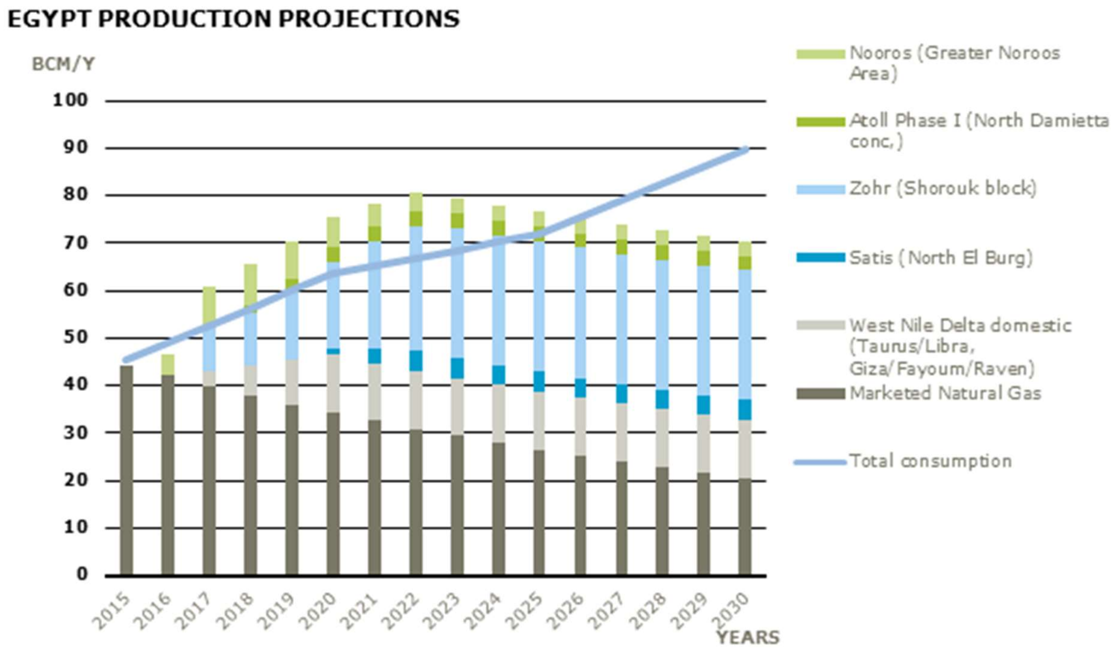
Source: CESI/Ramboll

10.14.6 Industrial sector

With the current pricing regime industries will pay market prices for gas in Egypt. Many of them rely on exports to the world market and are thus dependent on global demand for their products. In our opinion they could face a competitive advantage in the event that Egypt again becomes self-sufficient with gas as competitors may face even higher energy costs (taxes included) and do not have the same advantages with respect to population and geography. In order to keep things simple we assume an annual growth rate of the industries of 3% p.a.

7) The undersupply from domestic sources may continue into 2017 depending on the developments in new production.
8) Some surplus production may be available from 2017-2025.

Figure 97: Egypt Natural Gas Demand and Supply



Source: Power sector modelling, annual accounts of companies, ECA.

It must be emphasised that several uncertainties exist in these high level projections:

9) The decline by 5% per year may be too conservative
10) Additional supply that we do not know of today will surely be added over the coming years.
11) Most of the supply increase origins from the Zohr field.

Regulatory developments

A new draft gas law was submitted to the State Council in November 2015 and has now passed the review in Dec 2016. Itis now been handled in Parliament where it will be presented to the Committee on 12 December. The law is expected to pass the Parliament in Q2 2017.

The law includes elements like third-party access, network code, licences, transparency etc. inspired by the EU gas regulation. There will also be accounting unbundling. The law concerns onshore pipelines only, with upstream offshore pipelines exempted.

10.14.7 Energy hub

The government wants Egypt to become a hub for oil, gas and electricity. Oil is high on this agenda, due to the natural advantage of the location the Suez Channel. This can include export of oil from Iraq and refining in Egypt for the sale of products. Here Egypt could be compensated in oil. In the longer term there could be an oil pipeline from Iraq to Egypt while in the short termoil will be delivered on tankers from Basra.

For gas the main driver is the idle LNG liquefaction plants, where gas from the new fields in the Eastern Mediterranean and e.g. Iraq can be liquefied and sold on the global market. Supply from Iraq would require a new pipeline between Iraq and Jordan and use of the Arabic pipeline, which is now partly idle. The new oil and gas pipeline could be routed in the same corridor.

The trilateral agreement between Cyprus, Israel and Greece on export of gas to Egypt is still valid.

The Arabic pipeline is presently only partly used – from the Jordan LNG plant to Jordan and as reverse flow to Egypt (100 mmscf/day). No pipelines between Saudi Arabia and Egypt and between Libya and Egypt are being discussed at present.

Possibilities for offshore pipelines exist, and the Law of the Sea allows for pipeline installation outside territorial waters. The technological development was also discussed and as Nord Stream with 1200 km length, the same length as from Egypt to Italy, is an example. However the problem is the depth of the water.

For electricity there are connections around the Eastern part of the Mediterranean. A connection between Saudi Arabia and Egypt is planned to be used mainly for daily balancing as peak loads take place at different times of the day. No net export/import is foreseen.

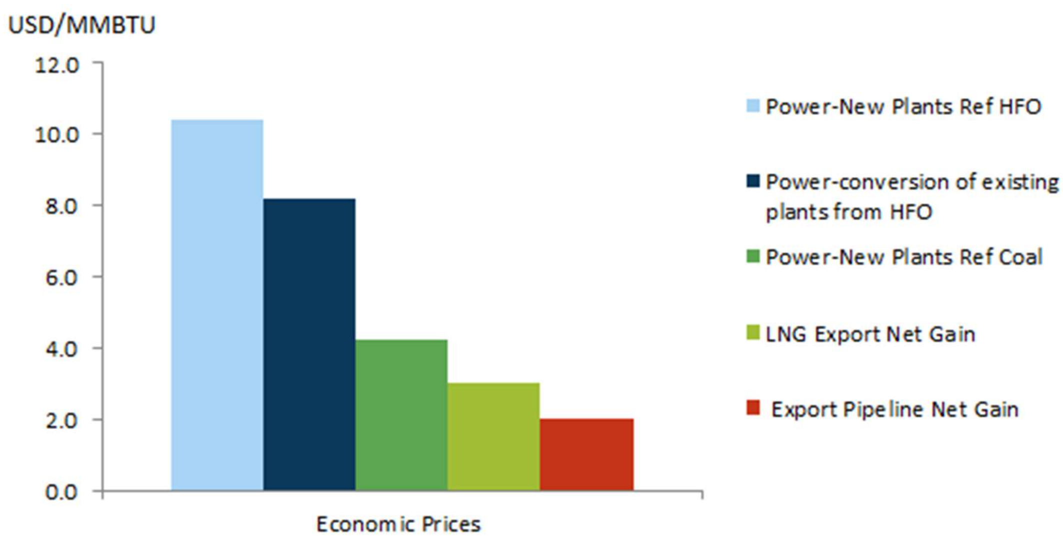
10.14.8 Valuation of gas and gas supply pricing

10.14.8.1 Supply of gas

Long run marginal cost could go as high as 6 USD/MMBTU, see Figure 93.

10.14.8.2 Internal valuation of gas

Assuming an efficiency of 41% and 43% for a newly constructed HFO and Coal power plant respectively, Egypt presents a relative favourable netback value of gas over both primary sources. Based on the assumption of LNG liquefaction related "sunk" cost, the net gain from LNG gas export considering 2020 market gas price in Europe will reach a 2$/MMBtu value.



For the HFO plant operating, the capital expenditure has been treated as sunk. This justifies a slightly lower netback value for gas compared to newly built power plants.
Observing the variation of efficiency values in the table of efficiencies, it has been assumed that Egypt will introduce new and more efficient CCGT plants by 2025. Leveraging higher efficient power plants means Egypt could be able to cater to growing energy demand while saving gas for LNG export trading in the international market.

10.14.9 Subsidies

Gas prices are set by the government and are subsidized. This includes general subsidies as well as cross-subsidies between different customers.

It has been decided to phase out subsidies over 5 years and we are now in the second year. For the power sector, the period of introduction may be extended to 7 years as the higher gas prices means that there is a need for more increase.

The basis for the prices is average supply cost, which is presently around 5 USD/MMBTU. The new Zorn field price will be in the order of 6 USD/MMBTU and is the most expensive indigenous produced gas. New LNG import prices are in the order of 8-9 USD/MMBTU.

The principles of gas prices are a.o.

- Industry based on net back from world market (e.g. fertilizer)
- New power plants – cost reflective prices
- Household (very small sector – only 3 percent) has life-line tariffs

Gas prices are based on prices in USD/MMBTU, which means that currency fluctuations are automatically taken into account. International gas prices are not included in the pricing. This raises the question if some kind of indexation to international prices for gas or other commodities could be made until the market start to function.

For the offshore Zorn field the operator will be able to sell gas directly to consumers in the market for their part of gas, profit share and cost, which is not expected to exceed 20 percent of the volumes.

For oil products, there is now free pricing for high octane gasoline.

The consultant ECA has recommended to start with price reform – to lower gas consumption – before making third party access possible to ensure that there is enough gas in the market.

The IEA estimates gas subsidies to 1.6 BUSD for 2014 out of a total of 23 BUSD for all energy subsidies in Egypt. This is down from 2.5 BUSD in 2013 as a part of the reform process and lower oil prices. The IMF estimated total fuel subsidies to 7.6 BUSD in 2015, down from 9.8 BUSD in 2014. Only imported fuels are valued at market prices, while domestic fuels are valued at production costs. The government estimates that, if valued at international prices, the economic value of energy subsidies would be more than double the financial subsidy figures reported in the budget.

According to the IMF these estimates undervalue the true economic costs as the Egyptian General Petroleum Company (EGPC) receives free crude oil and natural gas as part of its production-sharing contracts. Moreover, when international prices exceeded budget assumptions, the excess cost was borne by EGPC, affecting its financial performance and resulting in large arrears to foreign partners and suppliers. The negative feedback loop between subsidies and FDI in the energy sector stems from the diversion of an increasing share of energy production to satisfy the domestic market. This has led to external arrears to foreign energy companies and a reduction of their investment in new exploration. Moreover, despite large subsidies from the government, SOEs in the energy sector have generally not been able to meet the high energy demand resulting from low prices.

Since July 2014 natural gas prices to industries range from about 3 USD per MMBTU for the power sector (up from US 1.77 USD per MMBTU) to 8 USD per MMBTU for cement (up from 6 USD per MMBTU). Natural gas tariffs for households begin at about 1.70 USD per MMBTU for the lowest of the three increasing tariff blocks to 6 USD per MMBTU.

Following the July 2014 increase, the government intended to continue raising fuel and electricity prices over the next 4–5 years. The government however, failed to implement the fuel price increases planned for July 2015 and announced in December 2015 that at the end of the five-year subsidy program in 2019, 30 percent of the subsidy amount in 2014 would be retained[52].

The authorities' strategy also included a rolling out of smart cards for liquid fuels to target subsidies and limit smuggling.

The gas subsidy removal program is on hold and the target level reduced to 70%. This could be a barrier for future investment in new exploration and gas trade by foreign investors if there is a risk the production is diverted to the domestic market.

[52] Fossil Fuel Subsidy and Pricing Policies Recent Developing Country Experience Masami Kojima. Energy and Extractives Global Practice Group, World Bank, January 2016

10.15 **Bahrain**

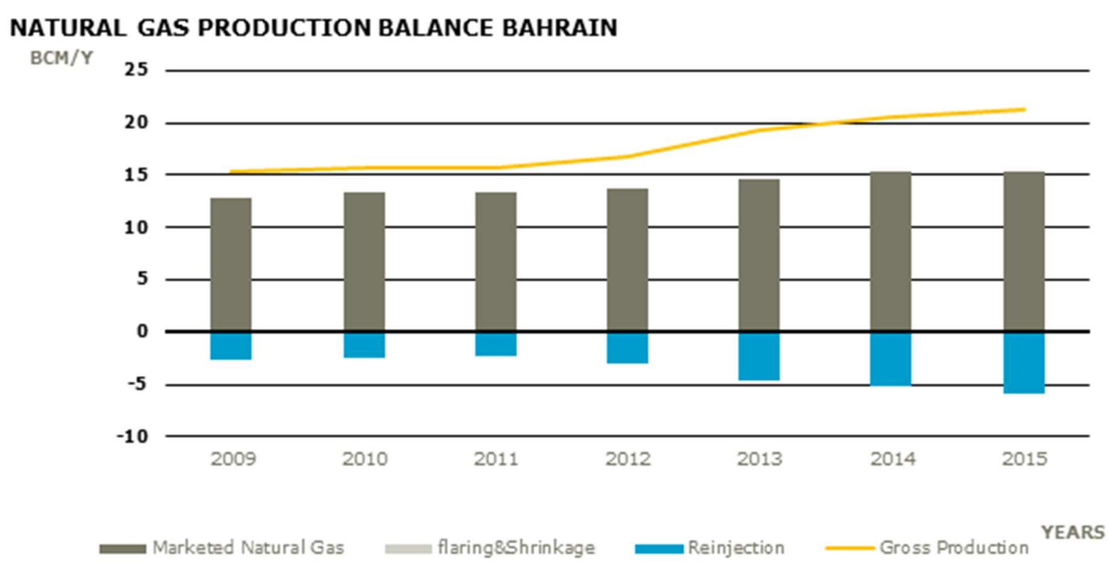
OAPEC data is used for historic data. Supply has been projected by adding the LNG terminal Bahrain is planning for 2018. Additionally, current production is assumed to be declining by 2% per year. Bahrain is pursuing increased domestic production and has a target of 27 bcm per year. This may be too optimistic. Currently there are plans of a dehydration plant as well as gas processing. However in total this would not be enough for an increase of up to 27 bcm/y. The official reserve figures of 92 bcm (OAPEC) do not support much more production in Bahrain; however the reserves might not be updated.

To project demand we used the results from modelling the power sector and added 2% growth in the industrial demand from 2018.

10.15.1 Gas supply

In 2015, Bahrain produced 15.5 bcm of gas, which is consumed in power generation, aluminium and other industries. The growth in gas production has not been able to keep up with surging demand for gas and is becoming increasingly difficult as old fields go into decline and new fields have to be developed at greater depths than previously. Thus the Bahrain Oil & Gas Authority has awarded a contract for a BOOT LNG import terminal which is under construction. The project is scheduled for completion by July 2018 and will have the capacity to import up to 8.3bcm per annum[53]. The aim is to optimize and expand gas production by adding 2 facilities for processing and dehydration of the gas. It is expected that the discovery of new fields will be insufficient to replace current production.

Figure 98: Natural Gas Production Balance Bahrain

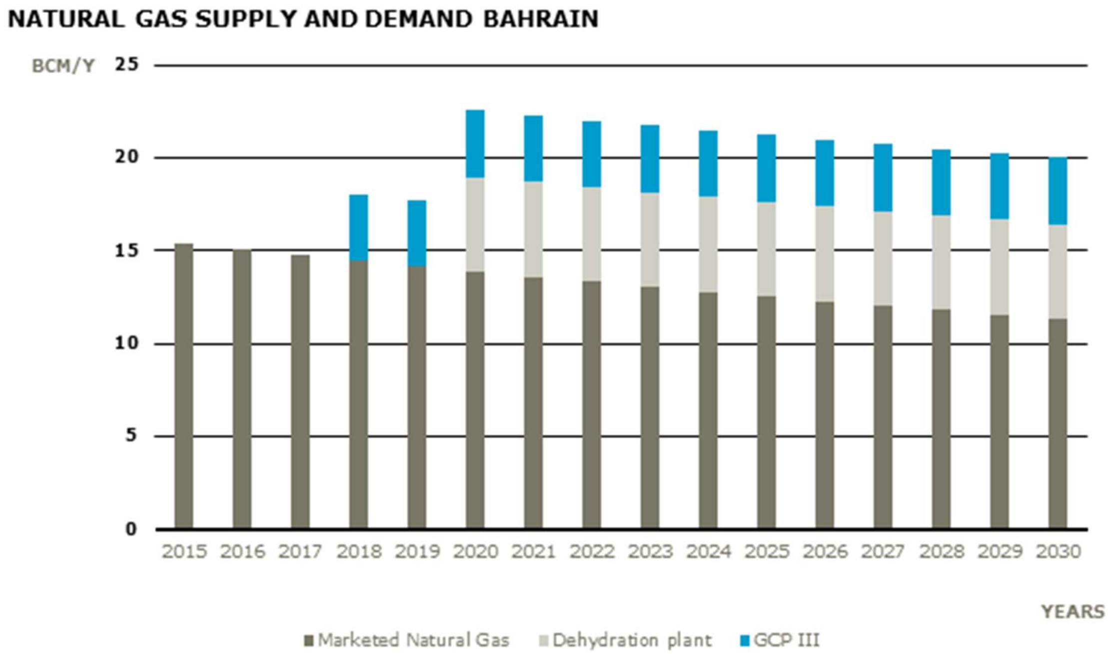


Source: OAPEC

Adding the two processing plants is expected to increase production capacity significantly as illustrated in Figure 99 below. Total production could decline to 20 bcm per year in 2030.

[53] Bahrain Oil & Gas Report. BMI Research

Figure 99: Projected natural gas production Bahrain

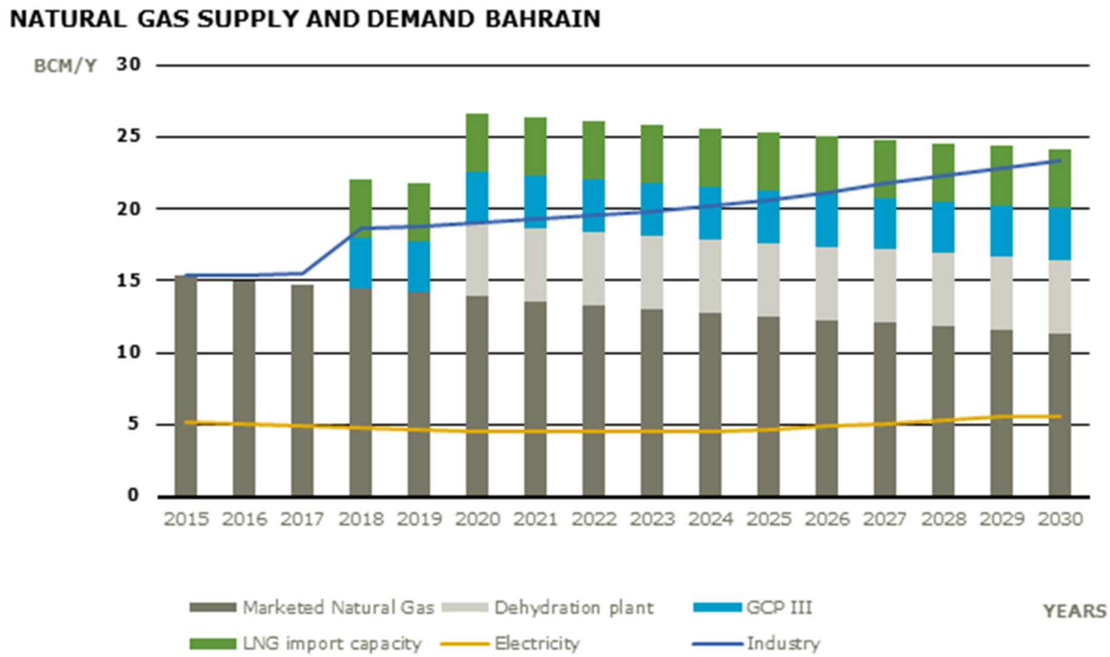


Source: Tatweer Petroleum, Ramboll, oxfordbusinessgroup. http://www.oxfordbusinessgroup.com/news/bahrain-meet-domestic-energy-demand-new-lng-terminal

10.15.2 Gas demand

Demand in the industry sector is set to increase steadily over the study period with increases of 2 % per annum mainly driven by the aluminium industry which will require 3-4 bcm additionally by 2018. The power sector is not projected to increase consumption significantly due to efficiency improvements. Adding gas demand to our supply picture shows that Bahrain seems well supplied under the assumption that the gas production can be increased.

Figure 100: Natural Gas Supply and Demand Bahrain



Source: Tatweer Petroleum, Ramboll, oxfordbusinessgroup. http://www.oxfordbusinessgroup.com/news/bahrain-meet-domestic-energy-demand-new-lng-terminal

10.16 Infrastructure development

Several projects are physically possible both with both Qatar and Iran just around the corner. Qatar in its new position could easily supply Bahrain now without sacrificing LNG export going elsewhere. In principle Iran could also supply but is still years away any large-scale exports as the South Pars field would have to be developed first. As a response to this supply situation, Bahrain initiated studies of the possibilities for import of LNG see Box 15.

Box 15: LNG import project in Bahrain

LNG Import Project

"The USD600-million Bahrain floating LNG project, which will be developed on a build-own-operate-transfer basis as joint venture between NOGA Holding (30%) and a consortium of Teekay LNG Partners LP, Samsung C&T Corp., and Gulf Investment Corp. (70%, combined). Designed to handle and process gas imports into Bahrain, the project will be located off the country's northeast coast and include: a floating storage unit (FSU); an offshore LNG-receiving jetty, breakwater, and regasification platform; subsea gas pipelines from the platform to shore; an onshore gas-receiving facility; and an onshore nitrogen-production plant. To be equipped with an initial capacity of 400 MMcfd but expandable to 800 MMcfd, the terminal will be owned and operated under a 20-year agreement beginning in third-quarter 2018."

Source: Oil&Gas Journal 2016

10.16.1 Valuation of gas and gas supply pricing

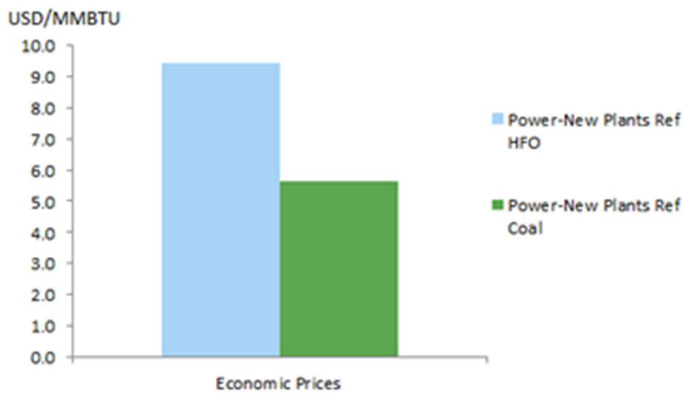
10.16.1.1 Supply of gas

Once the LNG is finalized the price of importing LNG will become the reference price in Bahrain.

10.16.1.2 Internal valuation of gas

Based on its maximum power capacity on CCGT and OCGT plants, Bahrain presents an undiscussable advantage in shifting to gas to meet domestic demand. Import of gas via the LNG terminal under construction will augment resilience to emergency of supply and add flexibility in energy supply.

Figure 101: Value of gas in Bahrain



Source: Ramboll

10.16.2 Subsidies

IEA estimates gas subsidies to be zero for 2014 in Bahrain out of a total of USD2.3 B for other energy subsidies (electricity and oil). IMF estimated explicit subsidies in the 2015 budget to USD 1.1 B[54].

Bahrain's gas price for existing industrial customers was increased by 50 percent starting in January 2012, from USD1.50 to USD2.25 per MMBTU, while the price for new industrial customers remained at USD2.50 per MMBTU (prices for new customers were increased from USD1.30 to USD2.50 In April 2010). In March 2015, the authorities announced annual increases of USD0.25 per MMBTU in the gas price for industrial users starting in April 1, 2015 until the price reaches USD4.0 per MMBTU by April 2021.[55].

Bahrain announced in December 2015 that it would raise the prices of diesel and kerosene to (USUSD0.32) per litre on January 1, 2016 and increase them by (USUSD0.05) per litre each year until January 1, 2019[56]

We conclude that there are no gas subsidies and as a result they do not pose a barrier for future gas trade. Petroleum products are scheduled to move close to international level.

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[54] IMF Energy Price Reforms in the GCC—What Can Be Learned From International Experiences? Nov. 2015.

[55] IMF Energy Price Reforms in the GCC—What Can Be Learned From International Experiences? Nov. 2015.

[56] Fossil Fuel Subsidy and Pricing Policies Recent Developing Country Experience Masami Kojima. Energy and Extractives Global Practice Group, World Bank, January 2016

10.17 **Oman**

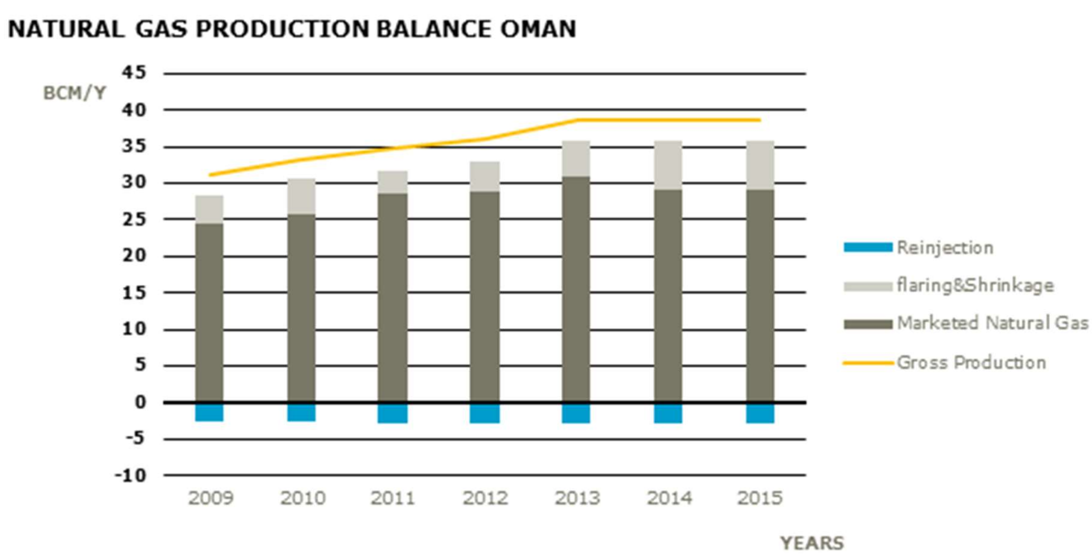
OAPEC data is used for historic data. Current production is assumed declining with 5% per year. A few field with the Khazzan as the largest have been added to the declining production.

To project demand we used the results from modelling the power sector and add 2% growth in the industrial demand and 1% improvement in efficiency in the energy sector.

10.17.1 Gas Supply

Oman produced 34.9 bcm of gas in 2015 and imported 2.1 bcm from Qatar through the Dolphin pipeline. Oman exported 10.2 bcm of LNG from two liquefaction facilities (of which 95% went to Asia, but also to Kuwait). Domestic gas consumption in power plants and industries has been outpacing supply in recent years and the LNG plants are running at low capacity. Much of the gas production is from non-associated fields. The current division of gas production is not crystal clear. It is known from international statistics that the country is producing just below 40 bcm per year, however this includes flaring and reinjection which in total could amount to as much as 10 bcm, implying that marketed gas is around 30 bcm per year.

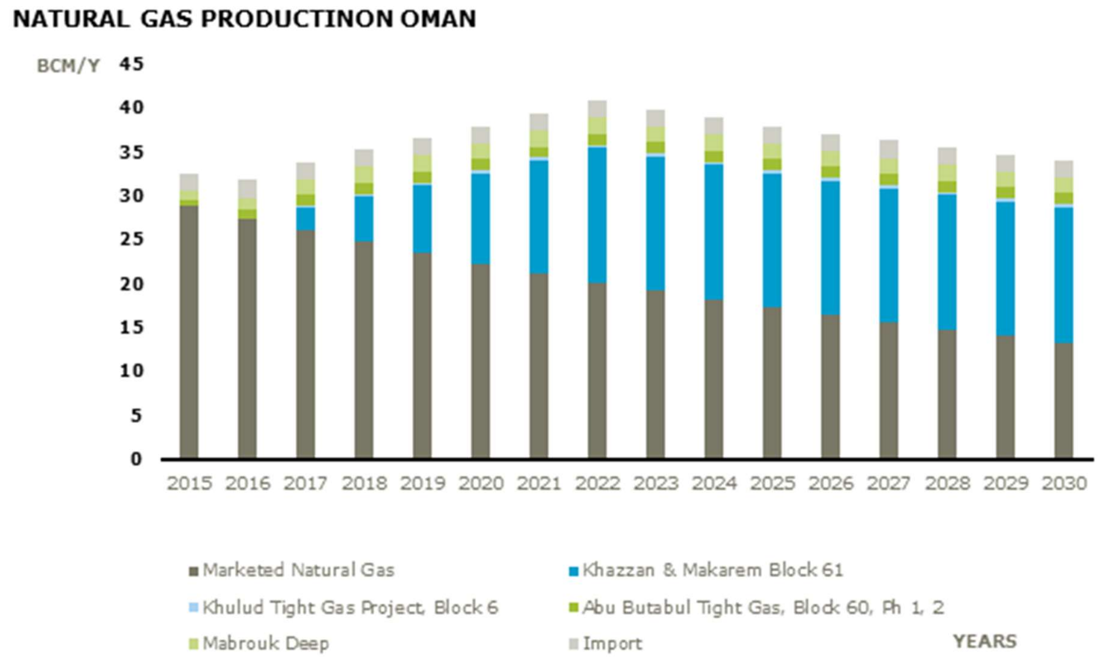
Figure 102: Natural Gas Production Balance Oman



Source: OAPEC

Focus in the upstream sector has been to provide IOCs incentives for E&P activities additionally the price of gas in Oman is amongst the highest in the region at about USD 3 per MMBTU. These efforts have paid off and in 2017 the largest field development in the history of Oman will be concluded with the first phase of the Khazzan field, delivering up to 28 mcm/d or approximately 10 bcm per year. The Khazzan field along with other major fields has been illustrated below. Additionally existing production is assumed to decline with 5% per year.

Figure 103: Oman Natural Gas Production



Source: own calculations. Assumptions 5% annual decline in existing fields and all 5 fields are brought into production.

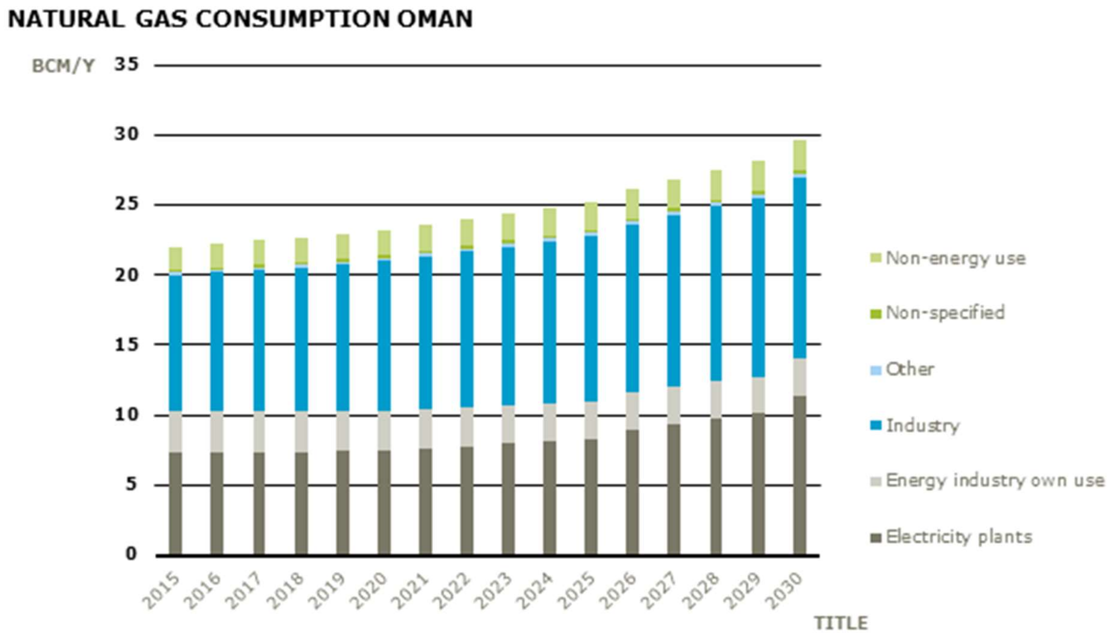
It is assumed that the gas produced is market gas as most of the fields are dedicated gas fields.

In addition to the marketed gas, Oman also imports and exports gas. For a number of years gas has been exported as LNG to Asia and the export agreements amount in total to 12 bcm/y and terminate in 2025. The government has announced that gas will not be exported as LNG post 2024. A Volumes of around 2 bcm annually are received through the Dolphin pipeline from Qatar transiting the UAE and we expect this to remain in place.

10.17.2 Gas Demand

Demand in Oman is concentrated on the power and the industry sector. For some years the supply situation to these sectors looked tight due to a very high need for gas in both sectors. The power sector is expected to increase from around 7 bcm a year today to 11 in 2030

Figure 104: Natural gas demand Oman

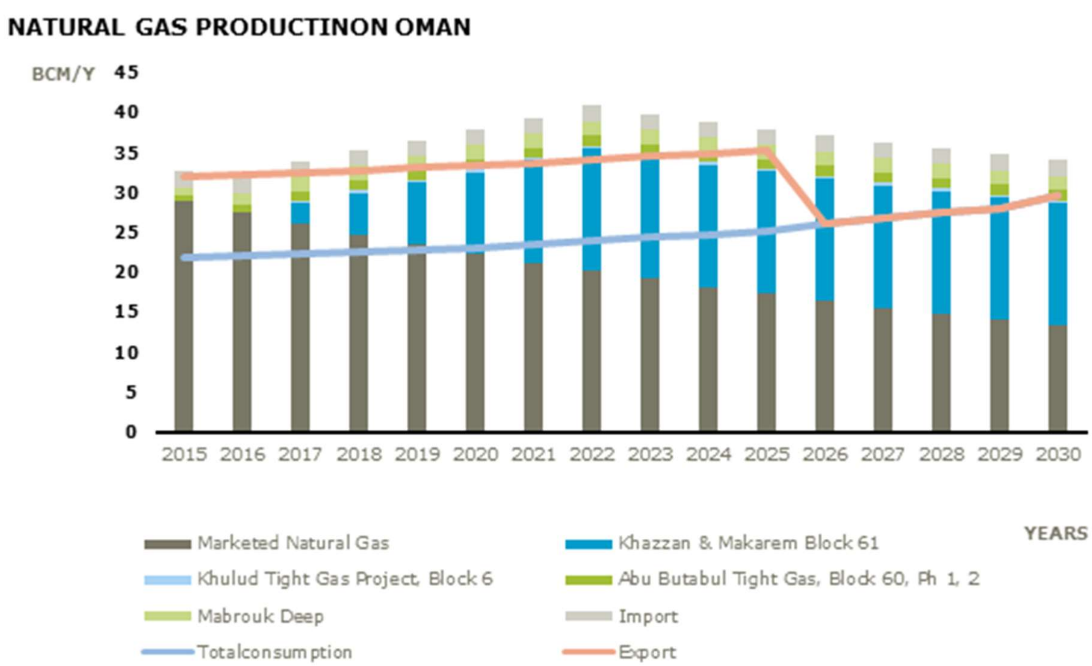


Source: Ramboll

10.17.3 Gas Balance Oman

The government has previously promised availability of gas for all sectors until 2019. However with new production coming online it seems that demand and volumes for export will be secured beyond 2019.

Figure 105: Gas Balance Oman



Source: Ramboll

10.17.4 Potential for new infrastructure

Although Oman may seem self-sufficient with gas there are a number of infrastructure developments which may increase trade across borders:

Gas storage:

Oman has a potential for gas storage providing flexibility during the summer and filling up either with import from the Dolphin pipeline or with own production during winter.

This is supported by:

- The demand side is highly seasonal.
- LNG demand in Asia peaks during the summer this leaves less gas for Oman during the summer than during the winter.
- Optimization of the import from Dolphin
- Possibilities for planning the production better
- Security of supply concerns.

Pipelines import infrastructure:

Iran – Oman has been on the drawing board on several occasions. The purpose of this pipeline would primarily be to utilize the LNG export facilities of Oman. The decision not to focus on export of Omani gas must thus stem from an expectation that the surplus which Oman seems to have when looking at the production forecast must be reserved for potential increases in consumption or saved for later generations.

10.17.5 Valuation of gas and gas supply pricing

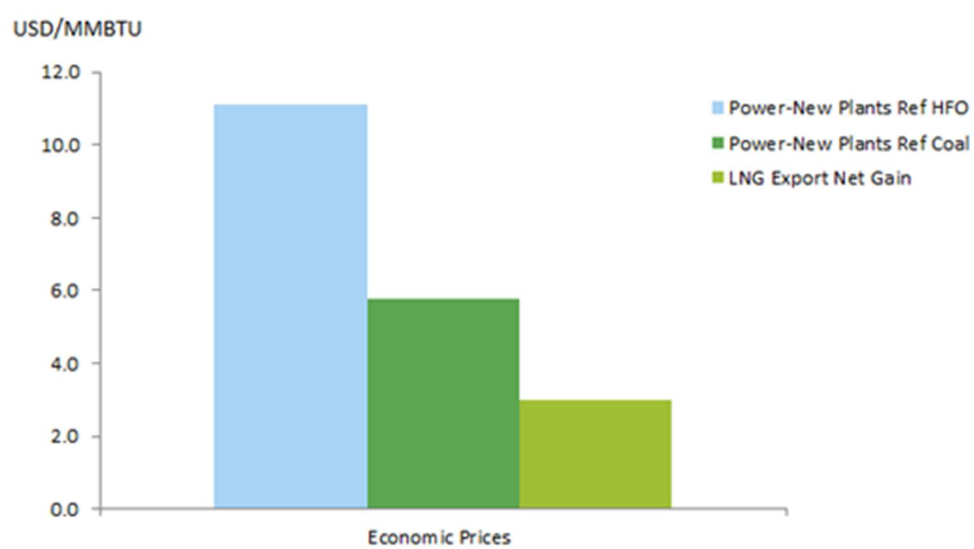
10.17.5.1 Supply of gas

Long run marginal costs of additional domestic gas in Oman was estimated to be in the range of 8 USD/MMBTU.

10.17.5.2 Internal valuation of gas

In the energy mix of Oman natural gas is the only primary energy utilised. Therefore the netback values herein presented are considered as fictitious values derived from considering generic assumed efficiencies for new HFO and coal power plants of 35% an 40% respectively. The relative high value of gas export via LNG has been derived assuming "sunk" capital cost in the LNG cycle overall cost estimate.

Figure 106: Value of gas Oman



Source: Ramboll

10.17.6 Subsidies

IEA estimates gas subsidies to be USD 2.5 B for 2014 in Oman out of a total of USD 7 B for all energy subsidies. IMF estimates explicit energy subsidies for 2015 of B 0.8 B, and subsidies due to pricing below Benchmark to be USD 2.8 B, down from USD 5.8 B in 2014.

Natural gas prices in Oman are the highest in GCC, USD 3/MMBTU after a doubling in 2015. Petroleum products are 80% to 95% of international levels, also the highest in GCC. In 2016, the government implemented fuel subsidy reform, linking prices to international prices with monthly revisions to consumer prices. Electricity prices however are low. There is a proposal to increase electricity tariffs for these users.

We conclude that there are no gas subsidies. The gas price is USD 3/MMBTU, the same as the benchmark for the US gas price 2016-20 in this report and higher than netback from LNG exports. The IEA estimates for the gas subsidy are from 2014 and do not capture the latest gas price increases. We see no barrier for future gas trade from subsidies.

10.18 **UAE**

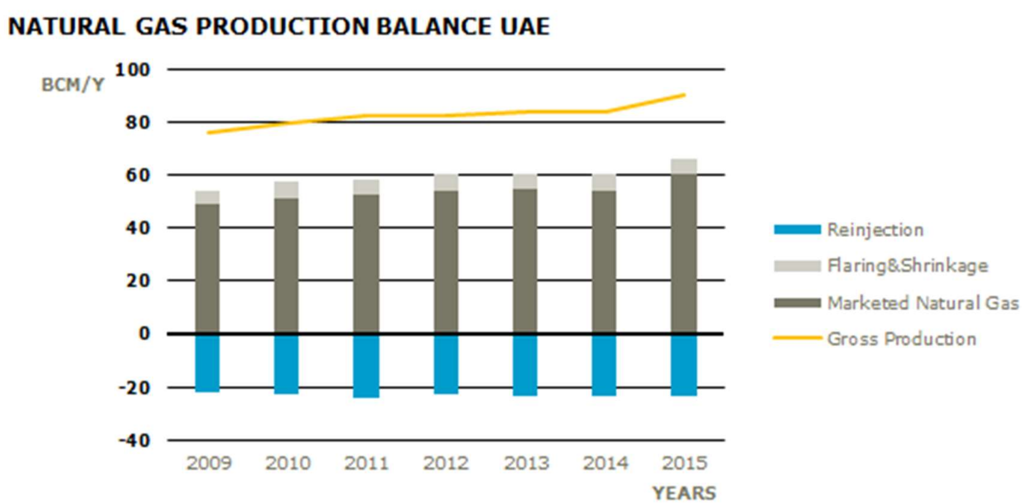
OAPEC data is used for historic data. Current production is assumed declining by 5% per year. 2 dedicated gas fields have been added to the declining production.

To project demand we used results from modelling the power sector and did not include expansions in the industrial sector, therefore this was kept constant until 2030.

10.18.1 Gas supply

In 2015, UAE produced 55.8 bcm of gas, consumed 69.1 bcm, and imported 19.8 bcm through the Dolphin pipeline from Qatar (some of which went to Oman). An agreement to increase the import through the Dolphin pipeline from Qatar was signed recently.

Figure 107: Natural gas production balance UAE



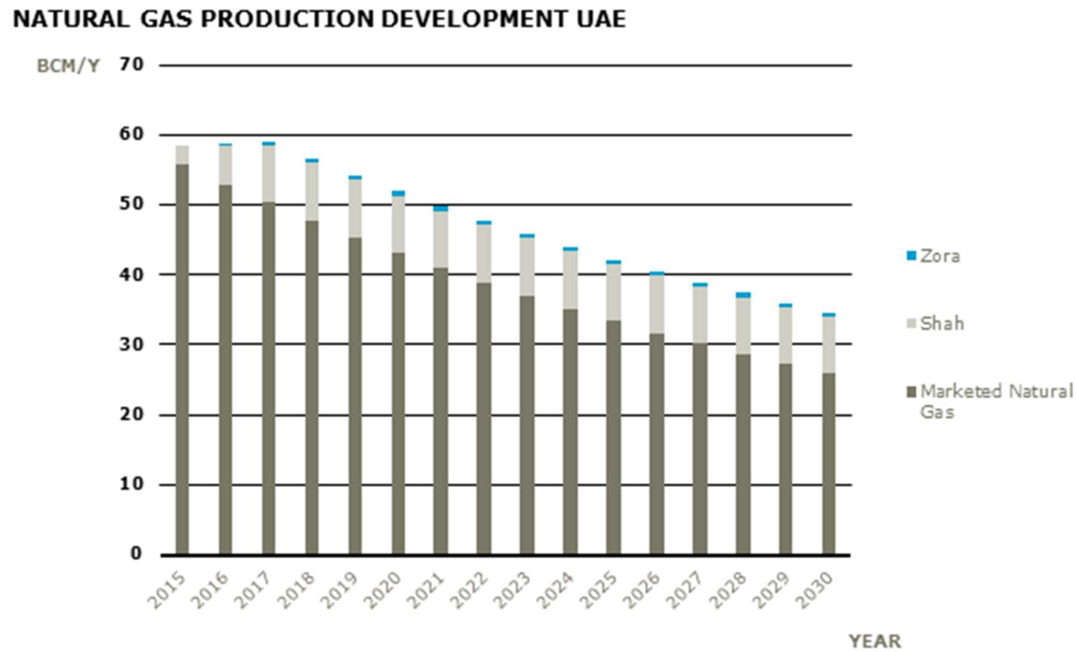
Source: OAPEC

Future production is expected to derive from the associated gas production and some new fields being brought into production. The UAE's natural gas has a relatively high sulphur content that makes it difficult to process and making it hard for the country to develop its extensive reserves.

The only major field included in the projections is the Shah field. The Shah field's hydrogen sulphide (H2S) content is 23%+. The reservoir temperature is about 150 degrees Celsius, with a pressure as high as 5,500 pounds per square inch. Thus although the Shah field was discovered in the mid-1960s, its remoteness and the technical complexity previously made development challenging. It is located about 210 km south-west of Abu Dhabi in the Empty Quarter. In addition to the Shah field,the minor Zora field has been included as well.

The Bab Sour gas field development has been postponed by Shell due to technical challenges and costs, mainly caused by the high sulphur content and is not considered in the analysis.

Figure 108: Natural gas production development

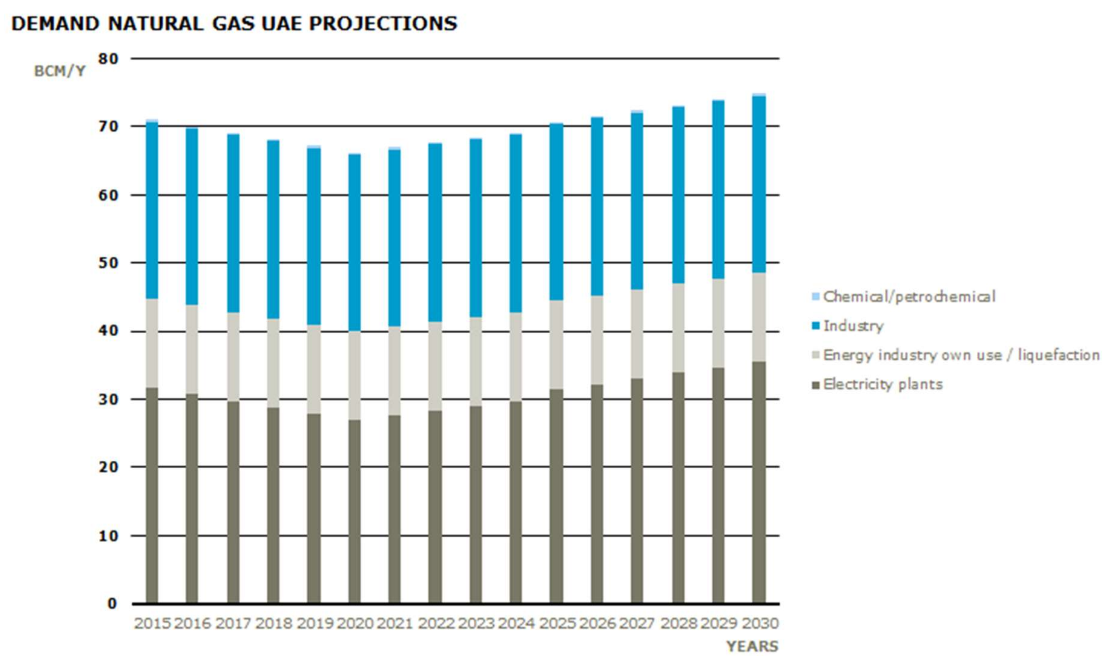


Source: Ramboll

10.18.2 Demand

Gas demand in UAE stems from the power sector, industrial use, and reinjection for enhanced oil recovery. This development is illustrated below.

Figure 109: Demand Natural Gas Projections UAE



Source: Ramboll

The power sector will be decreasing slightly only to increase in the latter half of the period.

Import - export

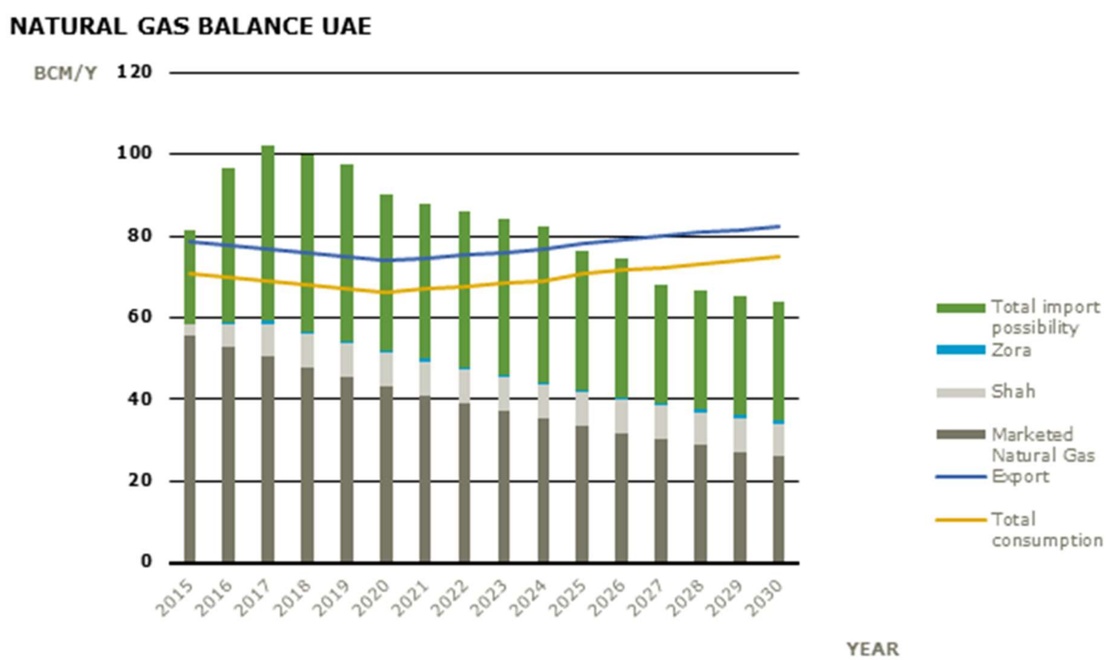
The Emirates were also active in the LNG trade: Abu Dhabi exported LNG and Dubai imported LNG. Abu Dhabi exported 4.3 mtpa LNG (6 bcm) to Japan under Long-term contract and sold 0.84 mtpa (1.2 bcm) spot/short term from the LNG plant in Das Island in 2015. Dubai imported 2.210 mtpa (2,8 bcm) LNG from seven countries, of which 1.290 mtpa was from Qatar and 0.11 mtpa from Abu Dhabi. The following lease expiry dates have been taken into account for the FSRUs.

LNG-Dubai-excelerate: expires: 2024
LNG-Dubai-Golar Freeze: expires: 2019
LNG-Abu Dhabi- Excellerate: expires: 2026

10.18.3 Gas balance

With the FSRUs there should be plenty of capacity to cover annual demand.

Figure 110: Natural Gas Balance UAE



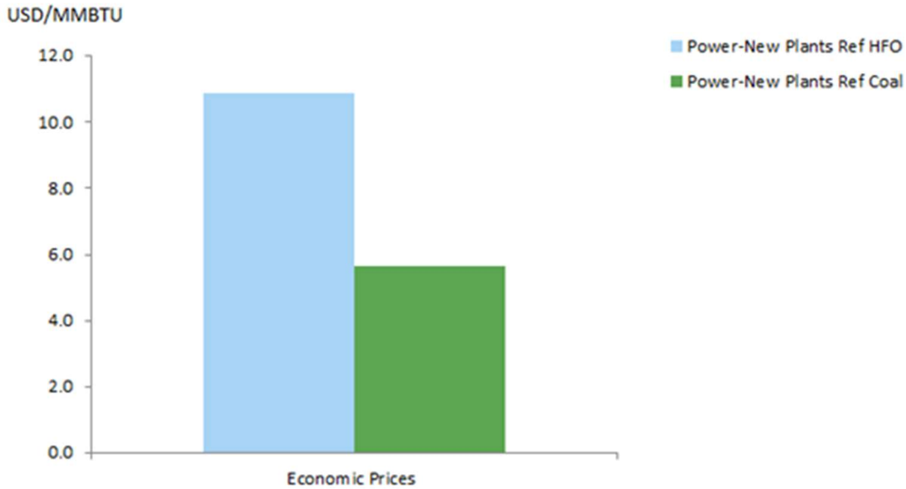
Source: Ramboll

10.18.4 Valuation of gas and gas supply pricing

10.18.4.1 Supply of gas

The long run marginal costs for the Shah field have been estimated to between 5 and 6 USD/MMBTU which corresponds well with the expectations.

10.18.4.2 Internal valuation of gas



Source: Ramboll

10.18.5 Subsidies

IEA estimates gas subsidies to USD 9.4 B for 2014 in UAA out of a total of USD 17.6 B for all energy subsidies. The IMF estimates USD 3.8 B of explicit energy subsidies for 2015, and subsidies due to pricing below benchmark to USD3.8 B, down from USD9.6 B in 2014 as a result of lower benchmark and price reform.[57]

Natural gas is still viewed mostly as a waste product associated with oil production and gas is delivered to Abu Dhabi Water and Electricity Company without a contract and without specifying quantity or price[58], which explains the high estimate of the gas subsidy. Domestic industries pay 0.75/MMBTU for natural gas. The LRMC of domestic gas production in the UAE was estimated at USD 5-6 /MMBTU due to high sulphur content[59]

Petroleum product subsidies were terminated August 2015, with pump prices of gasoline and diesel set on the basis of world prices and adjusted automatically every month. Electricity prices are around USD 0.10 per KwH, which is comparable to the US prices.

The government/power utilities bear the burden of low gas prices and pays international prices for imports of pipeline gas and LNG. Petroleum and electricity prices are at international levels. This puts a strain on government finances and can be a barrier to further trade.

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[57] IMF_Regional_Economic_Outlook_, Oct. 2016

[58] Reforming Energy Subsidies Initial Lessons from the United Arab Emirates TIM BOERSMA AND STEVE GRIFFITHS, Jan 2016

[59] OIES: Natural Gas Markets in the Middle East and North Africa. 2011

10.19 **Iraq**

10.19.1 Data and assumptions

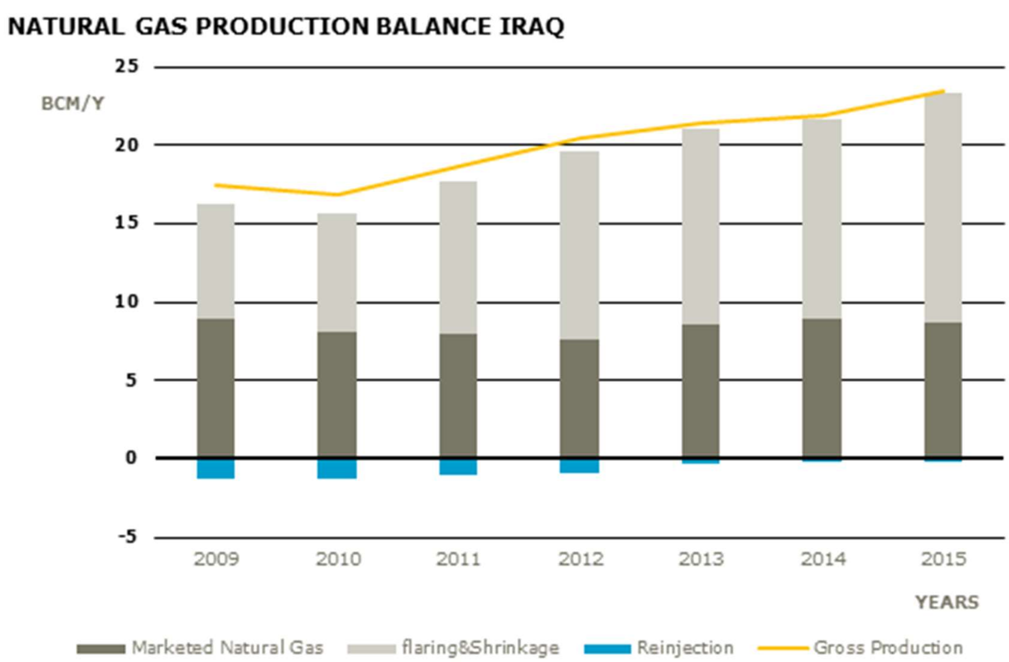
OAPEC data is used for historic data. The data deviates from BP quite significantly on marketed gas. Our data was reconfirmed by benchmarking against specific World Bank knowledge. While many other countries would face declining production Iraq will increase production, the question is whether gas can be evacuated and saved from flaring. We assume a gradual transition from flaring to reach 10 bcm in flaring in2025 down from just below 20 today. Additionally, 3 dedicated gas fields have been added to the declining production.

To project demand we used results from modelling the power sector and did include expansions in the industrial sector of 10% per year due to the current low level.

10.19.2 Gas supply

Iraq has three gas companies with different geographical areas, but non-associated gas production is small and Iraq flares most of its gas associated with oil production (17 bcm[60]). Gas sales production is reported by BP to be only 1 bcm[61] and oil is the main fuel for power generation. The 1 bcm is in our view too conservative and figures from OAPEC support this. The production balance for Iraq is presented below confirming the high flaring figures but in the other side rejecting the reports from BP of just 1 bcm in production of sales gas. The correct figure is 7-8 bcm per year.

Figure 111: Natural Gas production Balance Iraq



Source: OAPEC

New production is planned and we have identified the following fields:

- Bina Bawi - Onshore, low-cost, large anticlinal structure.
- Miran Onshore - low-cost, large anticlinal structure.
- Kurdamir gas cap Phase 1-3 - Onshore, associated gas cap, conventional gas.

In addition we assumed a base production of 27 bcm/y with continuous (slow) reduction in flaring.

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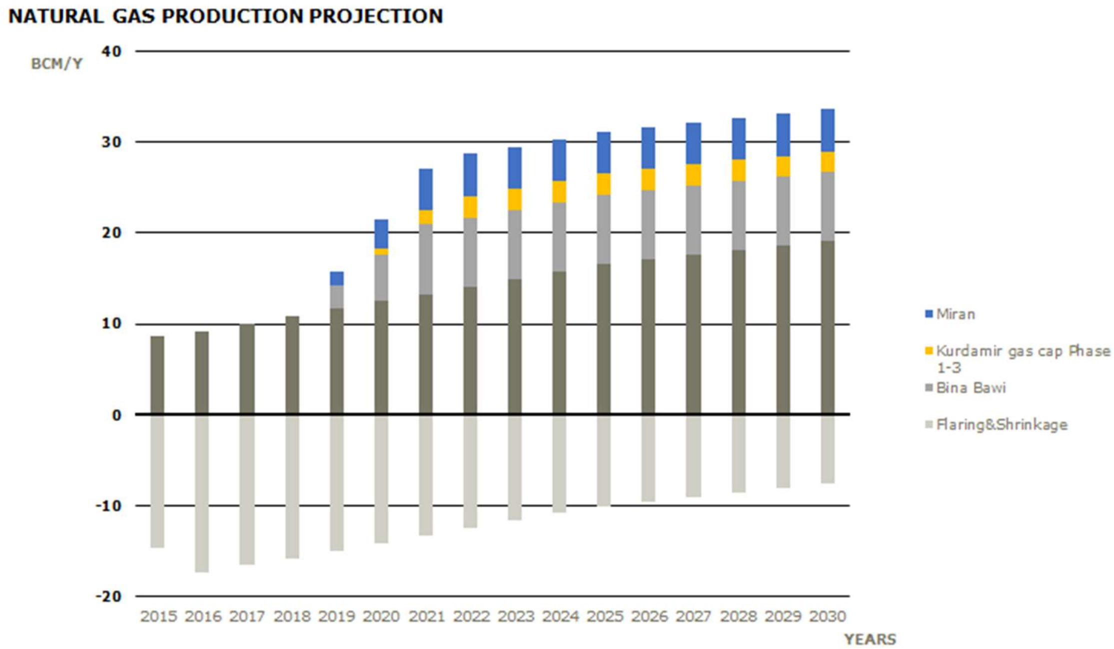
[60] GGFR estimate

[61] BP statistical review of World energy. Excludes gas flared or recycled

Figure 112: Natural gas production projection



Source: Ramboll

Imports

Iraq is planning to import gas from Iran by pipeline: A 10-year contract was agreed in 2013 for 14 bcm/year. Iran is making use of existing pipelines for exports. The delivery was planned to start in 2015, but has been delayed due to security matters[62]. Reports indicate that the contract was modified in 2015 to export additional 20mcm/d for 6 years (7.3 bcm on an annual basis) of natural gas to Iraq in cold seasons and 35mcm/d (12.7 bcm on an annual basis) in hot seasons, bringing the total to 40 to 65 mcm/d. (14.6- 23.7 bcm on an annual basis). The price of the gas has been kept confidential, but it has been set "in accordance with regional market's norms"[63]. It is unclear who will pay for the gas imports, which is mainly for power generation, but we assume it is the government.

10.19.3 Gas demand

Demand has been divided into the power sector and industrial sector. The power sector is the output of modelling while industrial demand is assumed to expand with 10% per annum.

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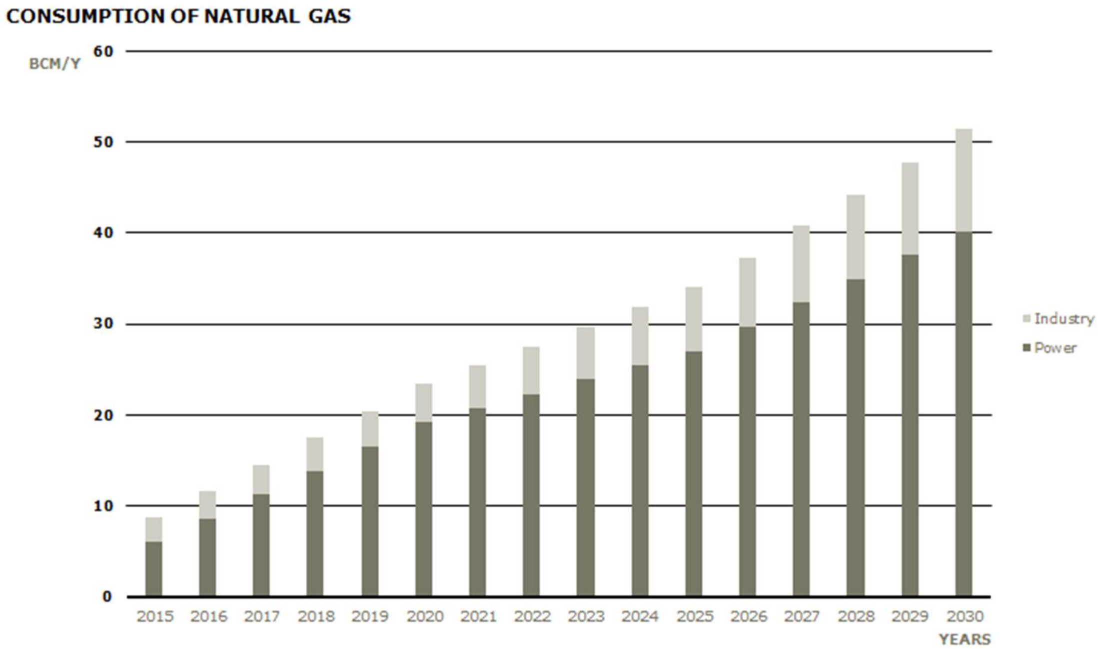
[62] IEA: Gas Medium Term Market Report, 2016

[63] en.farsnews.com Nov 15, 2015.

Figure 113: Demand of natural gas Iraq

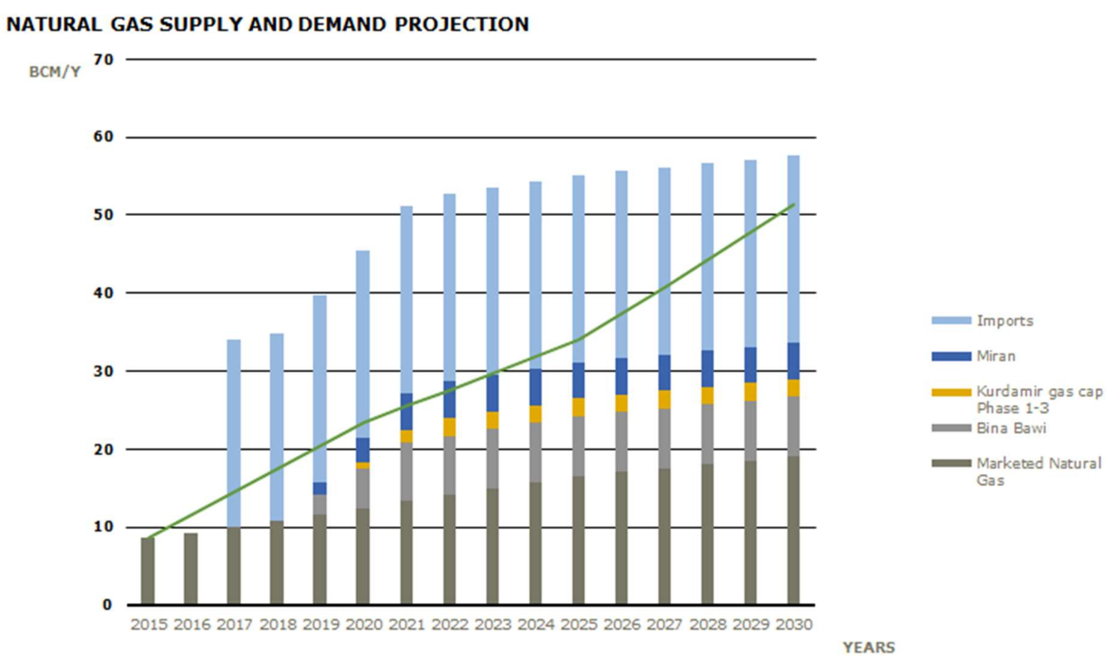


Source: Ramboll

10.19.4 Gas supply and demand balance

Adding the import capacity from Iran to the current supply outlook shows that potential volumes are significant and capable of covering the supply gap.

Figure 114: Natural gas supply and demand projectoion



Source: Ramboll

10.19.5 Valuation of gas and gas supply pricing

10.19.5.1 Supply of gas – LRMC

The breakeven prices of the 3 identified fields all lie between 1-2 USD/MMBTU indicating that gas resources are relatively cheaply developed - especially onshore.

10.19.5.2 Internal valuation of gas

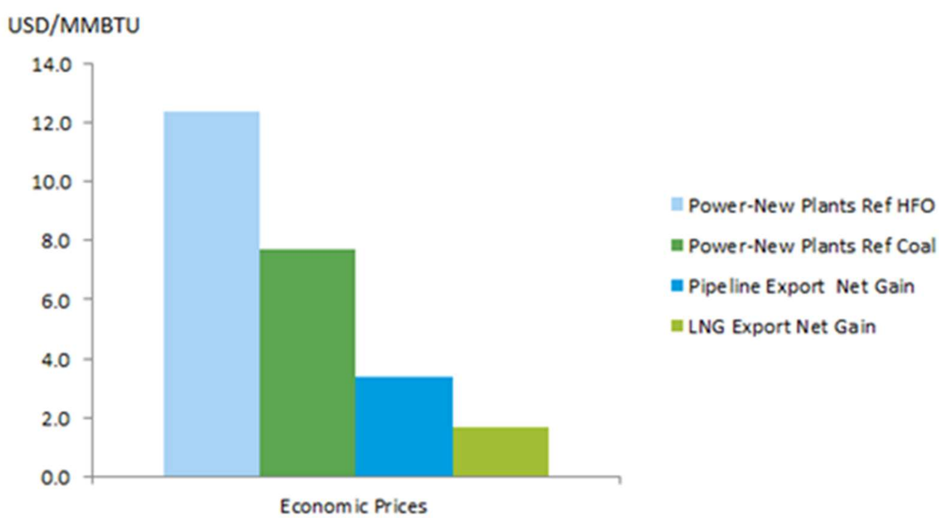
The high efficiency of CCGT plants above 50% offers a remarkable netback value in the usage of gas compared to coal. Considering a gas market price of 5USD/MMBtu, the net gain from LNG export has been calculated based upon the following assumptions:

- Liquefaction CAPEX of 4 USDbil and OPEX of 2% of CAPEX for a yearly LNG estimated capacity of 4.5 mtpa
- a WACC of 10%

To evaluate the potential gas value related to export via TANAP on-shore pipeline towards entry points to the European gas market., a net gain has been evaluated under the following cost assumptions:

- 943 kilometres long pipeline with an outer diameter of 48’’and yearly capacity of 23 bcm
- CAPEX of 9 BUSD and a OPEX equal to 2% of the CAPEX

Figure 115: Value of gas Iraq



Source: Ramboll

10.19.6 Subsidies

IEA estimates gas subsidies to be only USD0.1 B for 2014 in Iraq out of a total of USD12.4 B for all energy subsidies in the country, mostly for oil. The IMF estimates that direct costs of energy subsidies for fuel products are roughly 2.5 percent of GDP and the electricity subsidy bill is estimated at roughly 5 percent of GDP (USD 17.5 B). Gasoline is sold for USD 0.386/litre, diesel USD 0.343/litre[64], around 75% of the international level.

The government has started implementing reforms of electricity subsidies. These reforms are expected to increase electricity tariffs for energy-intensive consumers and improve service delivery.

[64] IMF Country Report No. 15/235. Aug. 2015.

Iraq is planning to import gas but has potential to be an exporter of LNG through the Basrah Gas Company JV in the long term when associated gas is utilized rather than flared and new gas fields developed. The large subsidies for electricity and petroleum fuels are unsustainable and when gas imports start up, the government's subsidy bill will increase, which can be a barrier to further trade.

10.20 **Kuwait**

10.20.1 Data and assumption

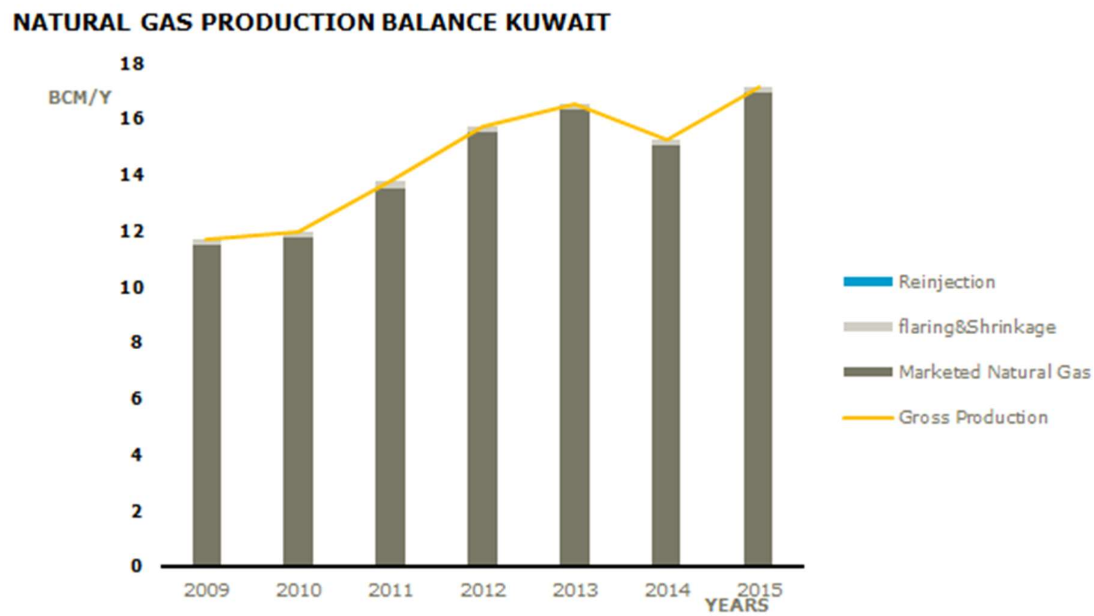
OAPEC data is used for historic data. Current production is assumed increasing with 5% per year. from 2020. No dedicated gas fields have been added to the production.

To project demand we used results from modelling the power sector and included a 2% yearly expansions in the industrial sector.

10.20.2 Gas supply

Supply is predominantly from associated fields. The northern part of the country is known to contain possibilities but so far Kuwait has been reluctant to invite foreign companies to develop these resources. Generally, marketed gas has been increasing. The associated nature of the production is revealed in 2014 when production declined – most likely due to low oil prices.

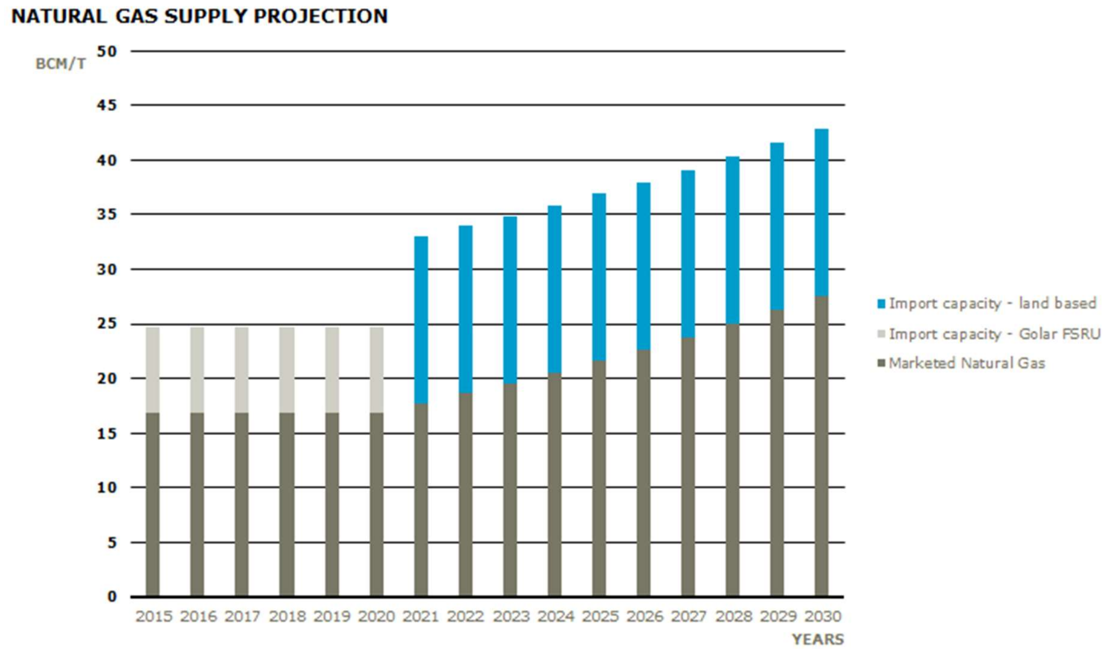
Figure 116: Natural gas production balance Kuwait



Source: OAPEC

Kuwait was the first country in the MENA region to begin imports of LNG in 2009. Since then gas demand has grown rapidly outpacing Kuwait own gas production, which is mostly associated gas, and LNG imports have increased. In 2010, Kuwait Petroleum Corporation (KPC) signed a LNG supply agreement with Shell and Vitol for 2010-2014 at prices indexed to Brent with a 10% slope. Kuwait was also active on the spot/short term market. Following this contract, KPC signed a contract with Shell for delivery of 1.07 mtpa (1.4 bcm) 2014-2019. In 2015, Kuwait imported a total of 3.04 mt LNG (3.85 bcm), from eight different countries, of which 0.45 mt came from Oman and 0.81 mt from Qatar, as well as re-exported LNG from France and Spain. The imports from Oman were spot/short term purchases, and almost half of the imports from Qatar were spot/short term purchases.[65] This implies that a little over half of the imports from Qatar were delivered under the Shell contract.

Figure 117: Natural gas supply projection

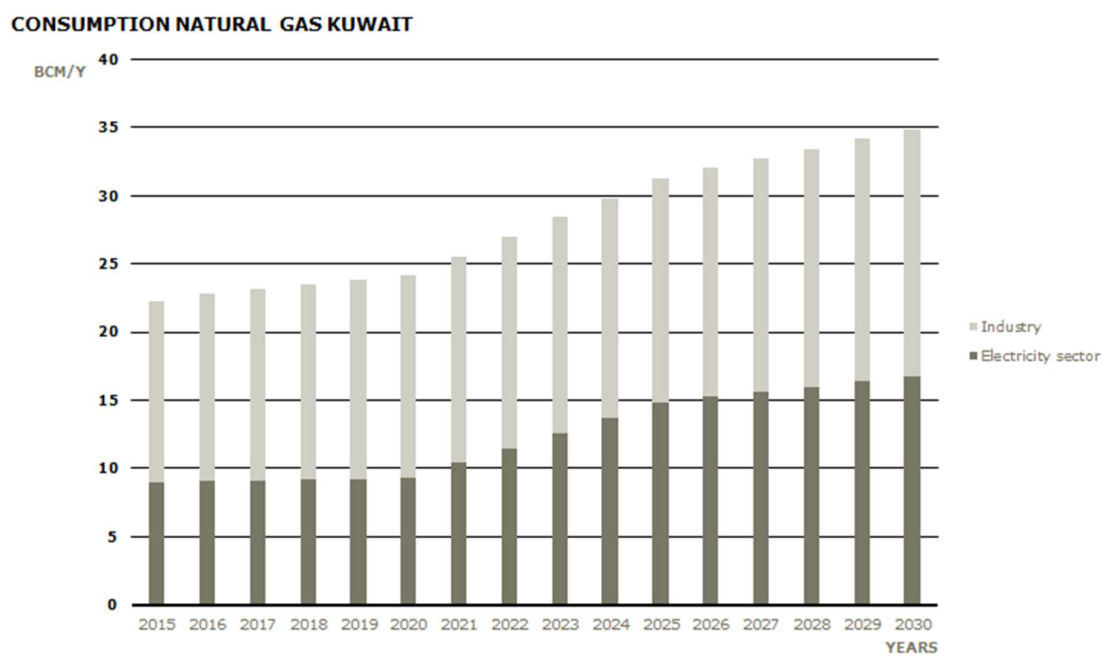


Source: Ramboll

10.20.3 Gas demand

Gas is consumed in power stations, the petrochemical sector and in the oil sector. Demand in the power sector is expected to almost double up to 2030. Additionally we would expect more moderate increase in the industry from 14 to 18 bcm per year.

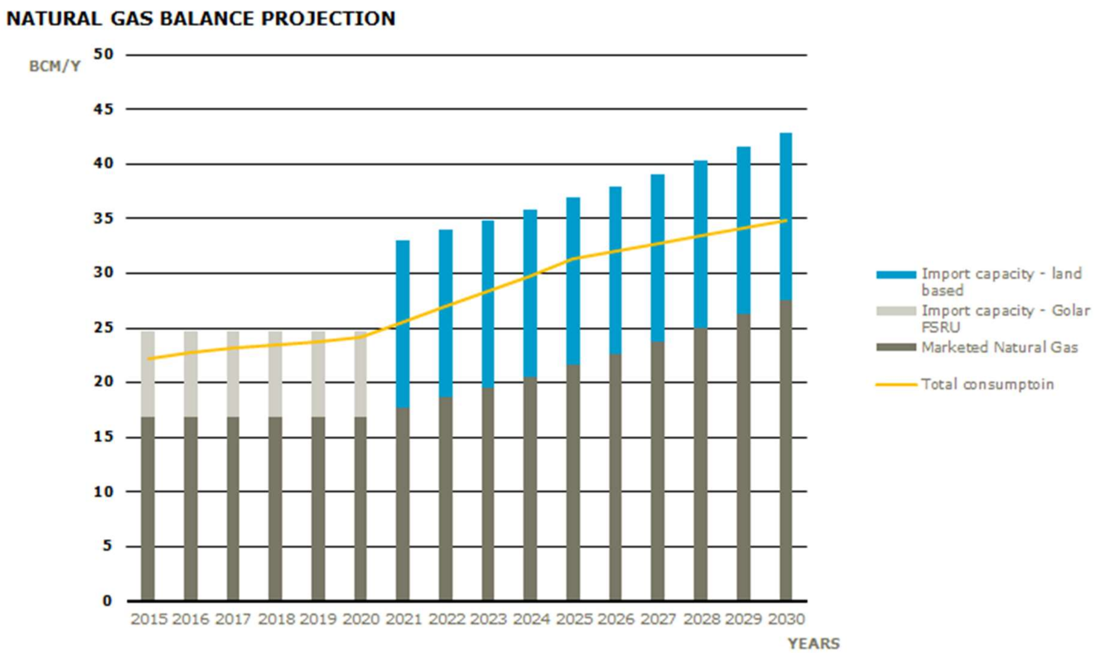
Figure 118: Consumption Natural Gas Kuwait



Source: Ramboll

10.20.4 Gas balance

Figure 119: Natural gas balance Kuwait



Source: Ramboll

10.20.5 Valuation of gas and gas supply pricing

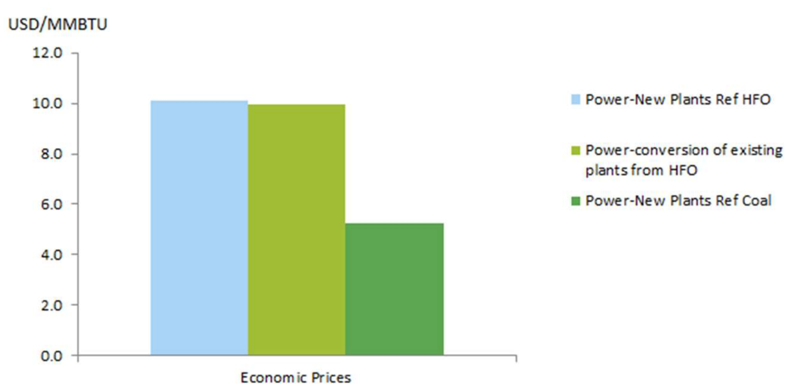
10.20.5.1 Supply of gas – LRMC

No new gas fields were identified

10.20.5.2 Internal valuation of gas

The thermal efficiency value of new CCGT allows for higher value of gas in energy generation compared to HFO and coal.

Figure 120: Value of gas Kuwait



Source: Ramboll

10.20.6 Subsidies

IEA estimates gas subsidies to be USD1.3 B for 2014 in Kuwait out of a total of USD 8.8 B for all energy subsidies in the country. The IMF estimates that Kuwait's on-budget costs for low energy prices (including water) were USD 7.8 B in 2014, of which 35 percent corresponds to petroleum products subsidies. The opportunity cost for selling energy products (gasoline, diesel, natural gas, and electricity) at prices below international prices is estimated at USD12.7 billion in 2014, and USD9.3 billion in 2015 due to lower energy prices in 2015[66].

The government announced an increase in gasoline prices of about 70 percent on average, effective September 2016. Additionally, a government committee will revise the new gasoline prices every three months depending on international oil prices. The government's plans to introduce gasoline subsidy reforms in 2016 were stalled when the cabinet resigned and parliament was dissolved following disputes between MPs and the government over fuel price increases. Gasoline prices are around 40% of international levels and diesel around 75%.

The price for natural gas charged to the power stations and petrochemical sector is indexed to Kuwaiti crude oil prices. Up to an oil price of USD 46, the gas price is USD1.0, USD47-60: USD 1.3, USD 61-80: USD 1.5, USD 81-100 USD 1.7 and USD2.0 and USD2.2 above USD100. In 2015 they were on average USD1.50[67].

The government/KPC bears the burden of low gas prices and pays international prices for imports of LNG. This puts a strain on government finances and can be a barrier to further trade.

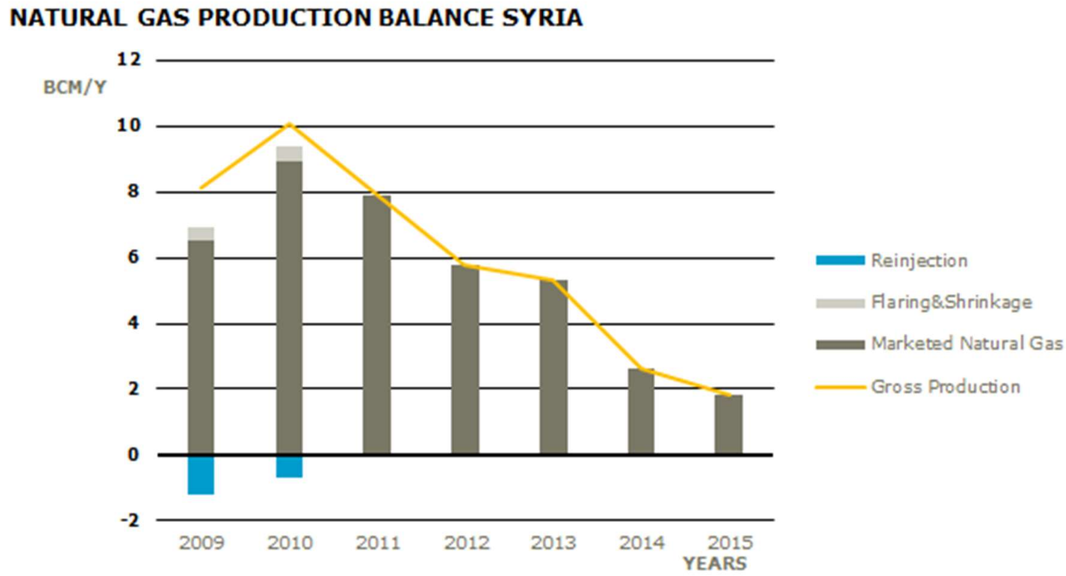
10.21 **Syria**

10.21.1 Gas supply

Syria produced almost 10 bcm of gas in 2010 before the war broke out. Today production is down to 2 bcm per year. It is likely that repairs to the fields are years ahead in the future. Thus we do not make any projections until 2020 but assume that the war is over by then and that a build-up of the country has been initiated.

[66] IMF Country Report No. 15/327, Dec. 2015
[67] [67]IMF Energy Price Reforms in the GCC—What Can Be Learned From International Experiences? Nov. 2015.

Figure 121: Natural gas production balance Syria



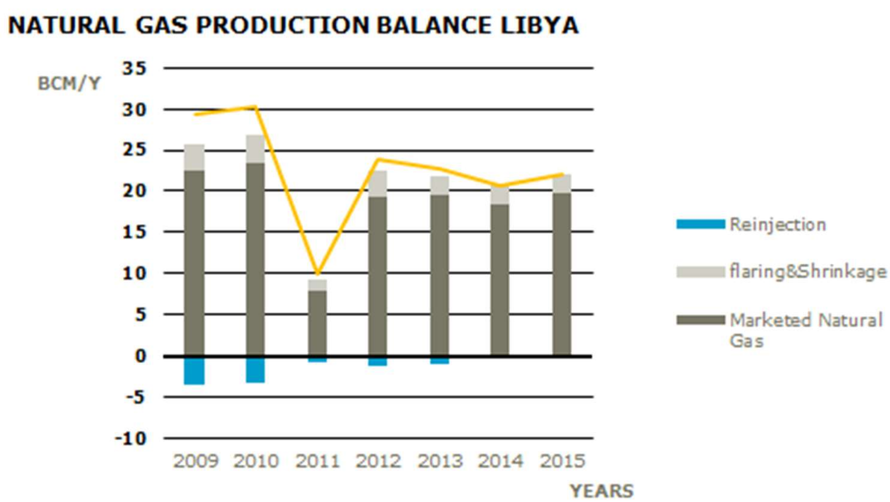
Source: OAPEC

10.22 **Libya**

10.22.1 Gas supply

OAPEC data indicates that marketed production in Libya is at 20 bcm per year. We do not believe that this is correct. The correct figure should be somewhere between 10 and 13 bcm/y. Thus we correct our starting point to 12,8 bcm 2015.

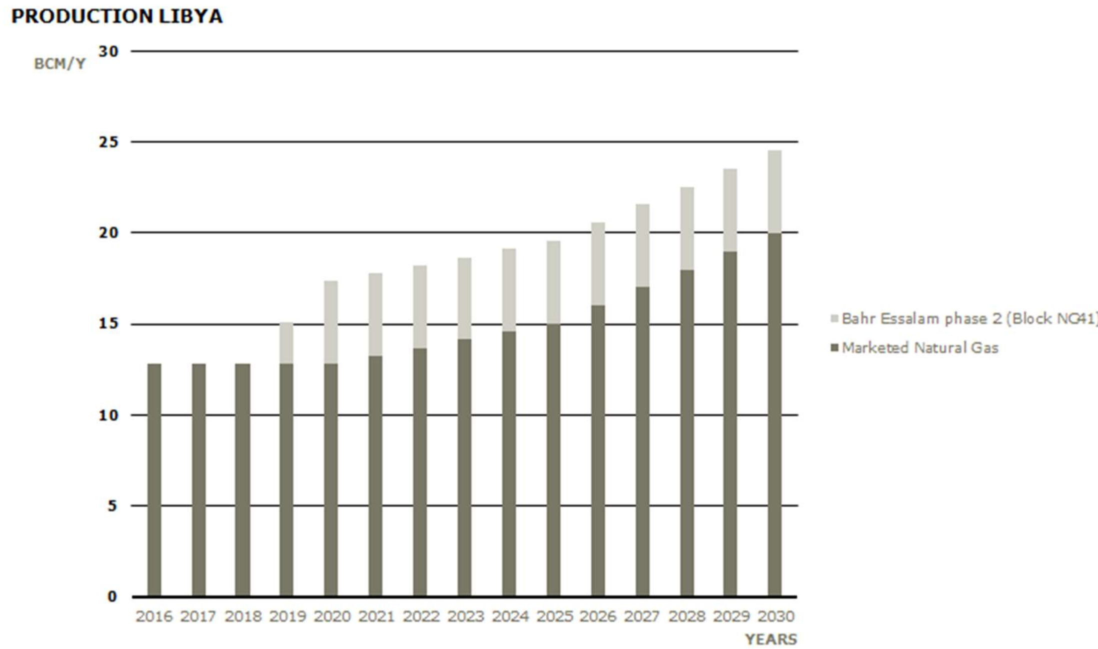
Figure 122: Natural gs production balance Libya



Source: OAPEC

Adding the only identified field and increasing production generally to 20 bcm year in 2030 which given Libyas resource situation does not seem impossible.

Figure 123: Production projection Libya



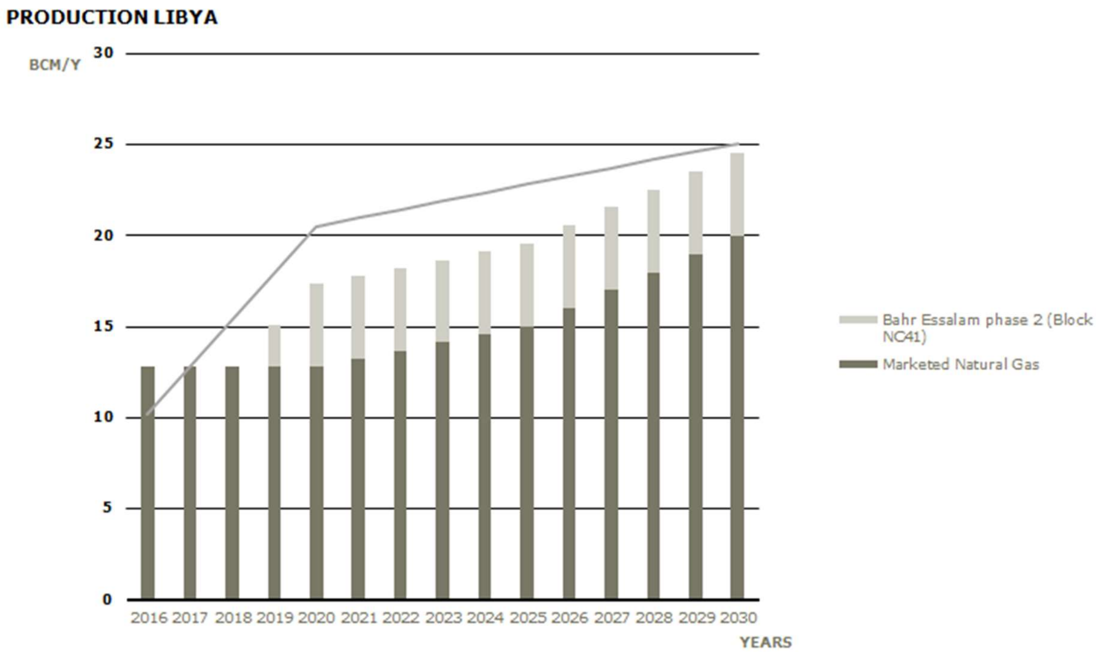
Source: Ramboll

10.22.2 Gas demand

Demand for gas will surge in the power sector from 2020 (16 bcm) to 5 additional bcm in 2030 according to the simulations. Additionally industrial demand will add to this but the level is very uncertain. Assuming 4-5 bcm for the industry constantly implies that there will be a deficit of gas, this deficit will be even larger if the export of gas is maintained and holds priority over domestic consumption.

10.22.3 Gas Balance

Demand will substantially increase in the power sector and therefore some deficit is expected in the short term unless production is increasing.



10.22.4 Valuation of gas and gas supply pricing

10.22.4.1 Supply of gas

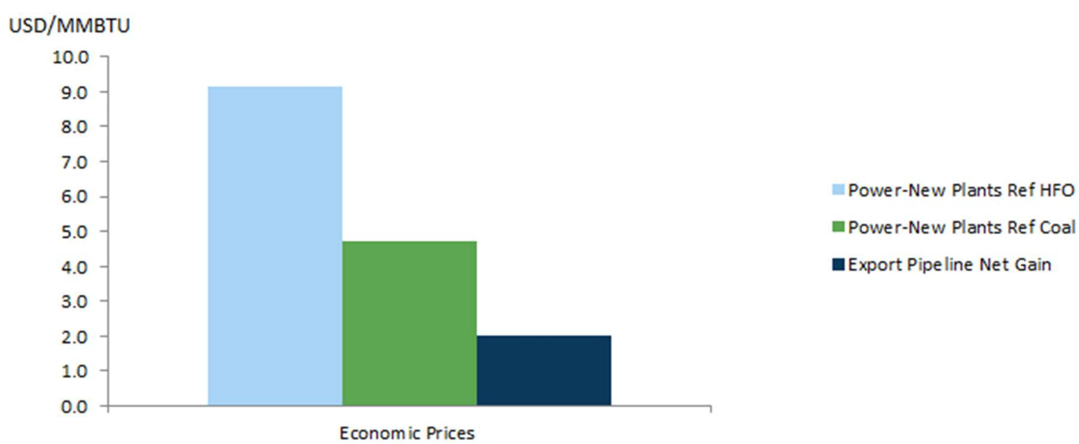
Only one field is known to come on-stream and we estimate the cost of this to around 1 USD/MMBTU

10.22.4.2 Internal valuation of gas

Libya presents a net gain from gas export towards European gas market hubs via a hypothetical offshore pipeline of circa 1,500 Km of 2 USD/MMBtu. This estimate hinges on the following cost assumptions:

- Pipeline capacity and outer diameter of 10 bcm per year and 36''
- CAPEX 9.4 USD B. and 2% of CAPEX as OPEX estimate
- WACC of 10% and a 2020 European market price of 5 USD/MMBtu

Figure 124: Value of gas Libya



Source: Ramboll

10.22.5 Subsidies

The IEA estimates energy subsidies at USD 7.4 B for 2014, up from USD 6.9 B in 2013. Libya had some of the lowest gasoline prices in the world and most of the subsidies are for petroleum products, USD 6.6 B in 2014 and USD 6.0 B in 2013. Gas subsidies are estimated to be only USD 0.1 B in both years and subsidies for electricity USD 0.8 B in both years..

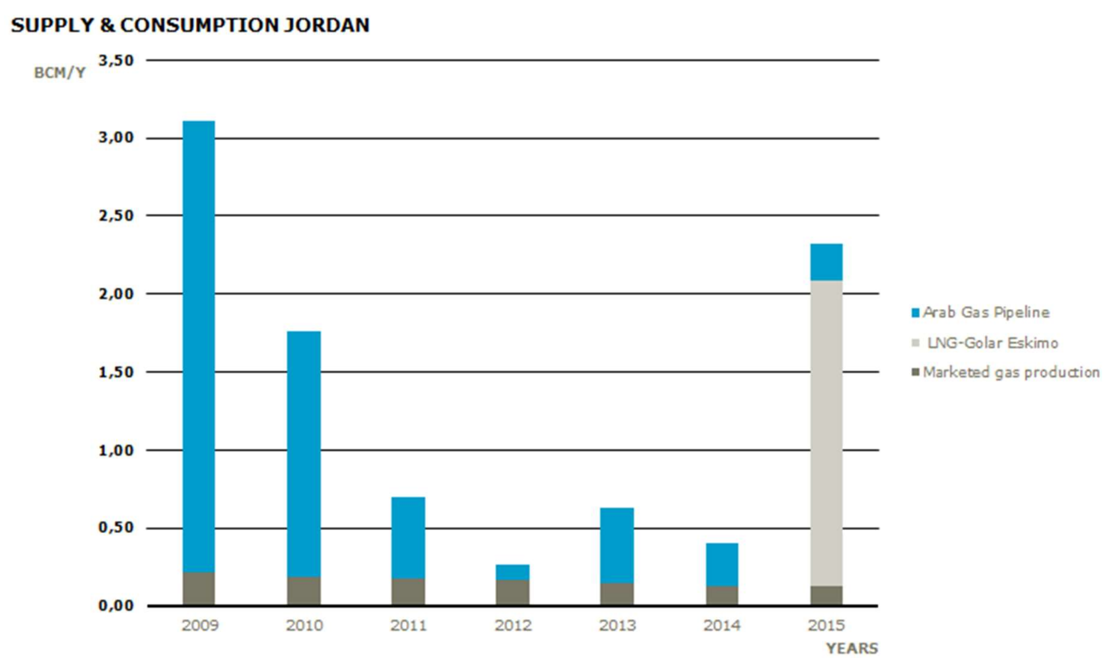
10.23 **Jordan**

10.23.1 Gas supply & demand

Jordan produces around 12-13 MMcf/d (0.12 bcm/y) from the Al Risha gas field[68], which feeds a power plant and started importing gas from Egypt through the Arab Gas Pipeline (AGP) in 2003. As the gas stopped flowing in the pipeline, Jordan turned to LNG imports in 2015.

Jordan signed an agreement for a ten-year time charter for a floating storage and regasification unit (FSRU) in 2013[69]. The FSRU was moored off the Red Sea port of Aqaba in 2015. Jordan signed a five-year contract for LNG supply in 2015 for the FSRU with Shell for 150 million cubic feet/day of LNG (reportedly paying USUSD500m annually[70]) and additional 78-cargoes LNG for deliveries in 2016 and 2017[71].

Egypt signed a MOU with Jordan for the use of excess capacity at the FSRU and booked 200 mmscfd of gas at the FSRU that has the capacity to deliver 500 mmscfd to the Jordanian gas transmission pipeline and signed a MOU with Algeria to supply LNG[72].



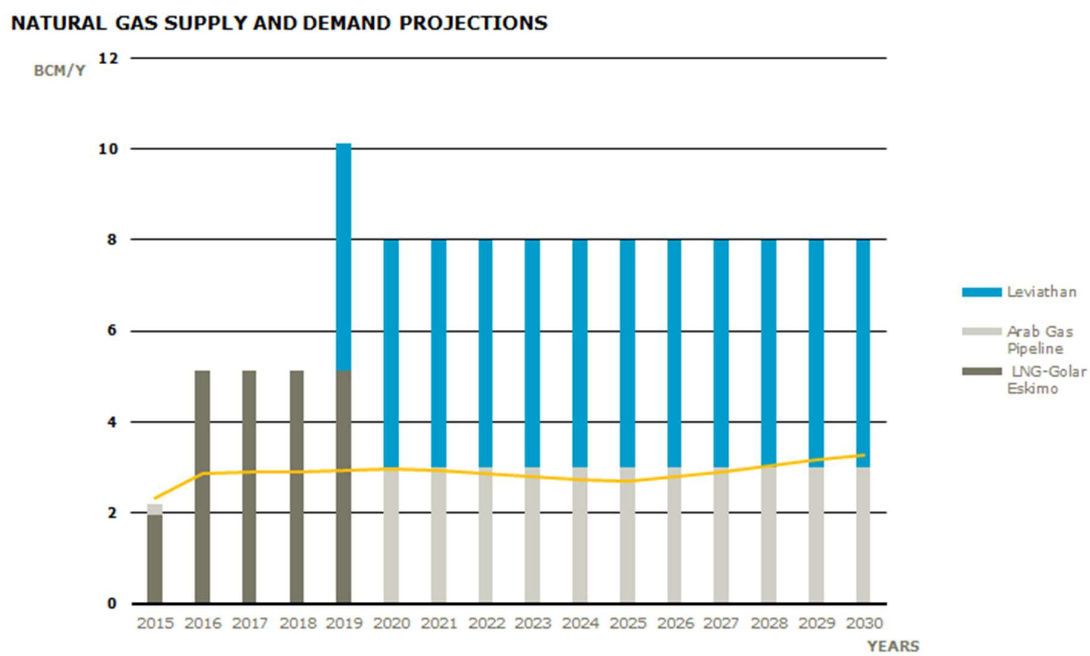
Source: OAPEC

[68] Jordan Times March 29, 2016
[69] GasTech News Sept 2, 2013
[70] Economist Intelligence Unit June 4, 2015
[71] Commodities Oct 14, 2015
[72] LNG World News May 16 and 18, 2016

10.23.2 Natural gas balance

It is clear that Jordan is well covered in terms of import capacity. The Arab gas pipeline is too unreliable to build a gas sector.

Figure 125: Natural gas supply and demand balance



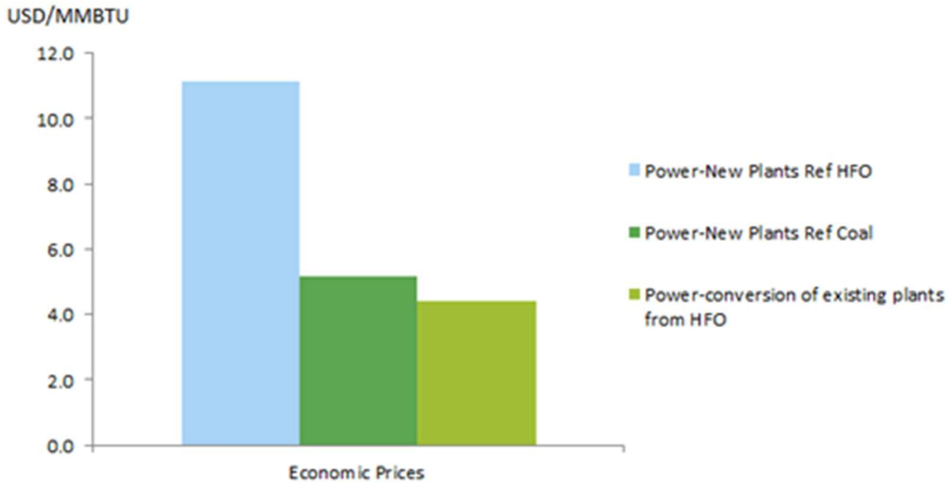
Source: Ramboll

10.23.3 Valuation of gas and gas supply pricing

10.23.3.1 Internal valuation of gas

Despite the assumption that Jordan can satisfy its energy demand via nuclear power plants by 2025, its energy mix is based on energy production from oil-products and natural gas. Due to the higher efficiency of CCGT compared to HFO power plants, the value of gas used in energy generation is high. In the case of conversion from existing HFO plant to CCGT, the lower value of netback value is justifiable by a lower associated gas price (fuel value) when the capital cost of the HFO plant is assumed as “sunk”.

Figure 126: Value of gas Jordan



Source: Ramboll

10.23.4 Subsidies

The IMF does not register any fuel subsidies. They do however estimate a transfer to the power utility NEPCO of Dinars 1572 M (USUSD 2.2 B) in 2014 and a sizeable cross-subsidization of small electricity consumers. Large corporations face high tariffs, and some have begun to find it cheaper to leave the grid[73].

The government in Jordan discontinued fuel subsidies and began adjusting fuel prices monthly at the end of 2012, with the exception of LPG. Prices have been regularly adjusted every month since 2012 and have closely tracked FOB prices in the Arab Gulf. To help households cope with price deregulation, the government introduced a cash transfer program covering 70 percent of households[74].

As for the pricing of gas from the AGP, Jordan (NEPCO) and Egypt concluded a 30-year sales and purchase agreement in 2001, stipulating a take-or-pay level of 90% of the 4.2 bcm annual contract quantity for Jordan and a price ceiling of USD1.5-2/MMBTU. The price ceiling for AGP gas to Jordan was increased to USD6/MMBTU in 2011 despite the fact that a series of disruptions had affected gas flows since January 2011.[75] Gas imports reached a level of around 300 MMcf/d (2.9 bcm/y)[76] Disruptions to supplies of natural gas from Egypt forced NEPCO to turn to more expensive diesel and fuel oil for power generation. In 2014, the amount of Egyptian gas imports was less than one-third of the contract volumes, and in 2016 after more than 10 attacks on the pipeline, gas supply to Jordan was halted. The supplies to Jordan were later renewed at a reduced rate.

We conclude that there are no gas subsidies and as a result they do not pose a barrier for future gas trade. Petroleum subsidies have also successfully been removed.

[73] IMF Country Report No. 16/295. Sept 2016.

[74] Fossil Fuel Subsidy and Pricing Policies Recent Developing Country Experience Masami Kojima. Energy and Extractives Global Practice Group, World Bank, January 2016

[75] OIES Issues in the pricing of domestic and internationally-traded gas in MENA and sub-Saharan Africa, Hakim Darbouche, June 2012.

[76] GasTech News Sept 2, 2013

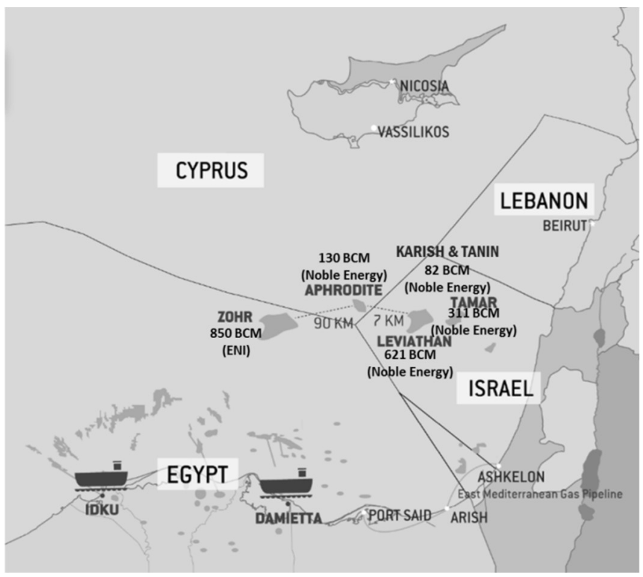
10.24 **Lebanon**

10.24.1 Gas supply

A sales and purchase agreement for Egyptian gas supply through the Arab Gas Pipeline to Syria was signed in 2001. The oil-indexed gas price ceiling was higher than for Jordan, close to USD5/MMBTU and the stipulated ACQ was 2.2 bcm. For its part Lebanon was receiving Syrian gas in lieu of Egyptian gas under a 15-year swap agreement signed in 2009 by the Egyptian NOCs and the Syrian Petroleum Company[77].

Lebanon is currently in the process of developing an offshore oil and gas sector and is in the process of defining the political and legal framework. It may beself-sufficient within a decade if successful in politically and with exploration. It has identified licenses and operators but the political climate prolongs the development.

Figure 127: Significant discoveries in the Eastern Mediterranean



Source: Middle East Economic Survey

It should be noted that some geopolitical risk is associated with developing the reserves with both Lebanon and Israel are making claims to the same areas offshore.

10.24.2 Gas demand

Gas was originally destined for the power sector of Lebanon, supplying one power plant in the country. Lebanon could increase its gas consumption in the power sector significantly from 0,2 bcm when the AGP was functioning to 2 bcm in 2030. Much will hinge on the development of the offshore reserves. It is unlikely that expensive import projects will be brought to the table before deeper knowledge of the offshore reserves has been obtained.

We firmly believe that Lebanon will use as much of the produced gas as possible domestically. This has been a requirement in several tenders for international firms and advisors.

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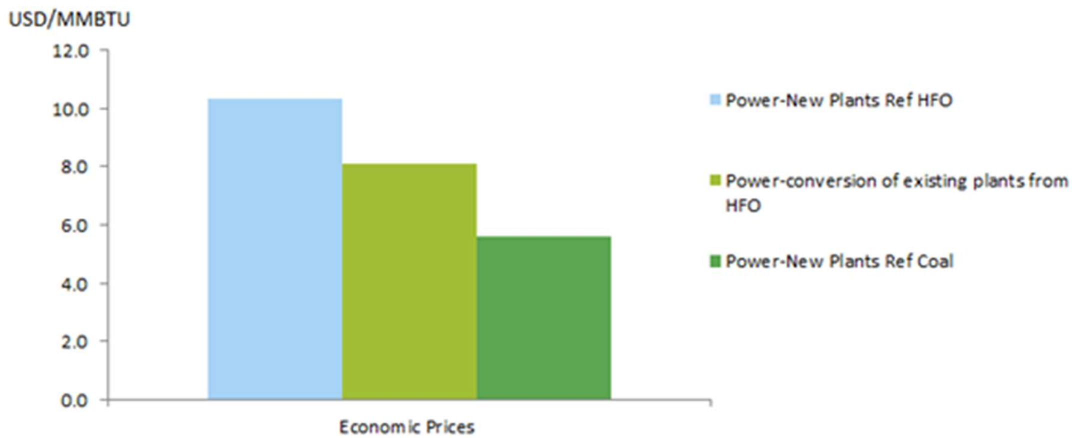
[77] OIES Issues in the pricing of domestic and internationally-traded gas in MENA and sub-Saharan Africa, Hakim Darbouche, June 2012.

10.24.3 Valuation of gas and gas supply pricing

10.24.3.1 Internal valuation of gas

As emphasised in the efficiencies table, Lebanon is assumed to increment its power plant fleet with highly efficient CCGT by 2025. This fact justifies a high netback value of gas employed in energy generation over less efficient oil-product fuelled plants.

Figure 128: Value of gas Lebanon



Source: Ramboll

10.24.4 Subsidies

Fuel price subsidies were de facto eliminated in October 2008 with the reintroduction of fuel excise taxes; final fuel prices are issued weekly via ministerial decree with the price based on cost (including distribution costs and station margins) plus fuel excise taxes. Remaining fuel subsidies in Lebanon are either in the form of direct cash transfers such as those given to Electricité Du Liban, or in the form of forgone revenues such as those resulting from a reduction in the gasoline excise rate in 2011 and the Value-Added Tax exemption on diesel oil in 2012[78].

We conclude that there are no gas subsidies and thus pose no barrier for future gas trade. Petroleum subsidies have also successfully been removed.

10.25 **Yemen**

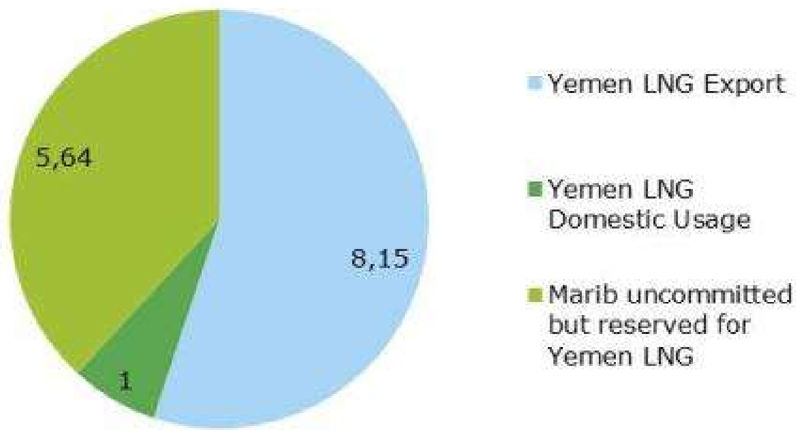
10.25.1 Gas Supply

Yemen is endowed with gas in the centre of the country. The main producing field is the block-18 Marib field. The Marib field has been producing both oil and gas since 1986. Total proven reserves in the Marib field constitute 78% of the total proven reserves, i.e. 14.79 TCF. The participants in the concession are Total 39.62%, Hunt 17.22%, YGC 16.73%, SK Innovation 9.55%, Kogas 6%, and Gassp 5% which have been granted exclusive rights to the Marib field by the Yemen Government. Currently 9.15 TCF of the proven reserves have been allocated to the Yemen LNG export project. 8.15 TCF of these 9.15 TCF has been earmarked for export via the consortia's LNG exporting facility at Balhaf. The remainder is to be used in the Marib Power plant phase 1, completed in 2012 and the Syawen power plant.

The reserves in the Marib field are thus distributed as follows.

[78] MoE/UNDP (2015). Fossil Fuel Subsidies in Lebanon: Fiscal, Equity, Economic and Environmental Impacts. Beirut, Lebanon.

Figure 129: Distribution of the reserves in the Marib Field, TCF

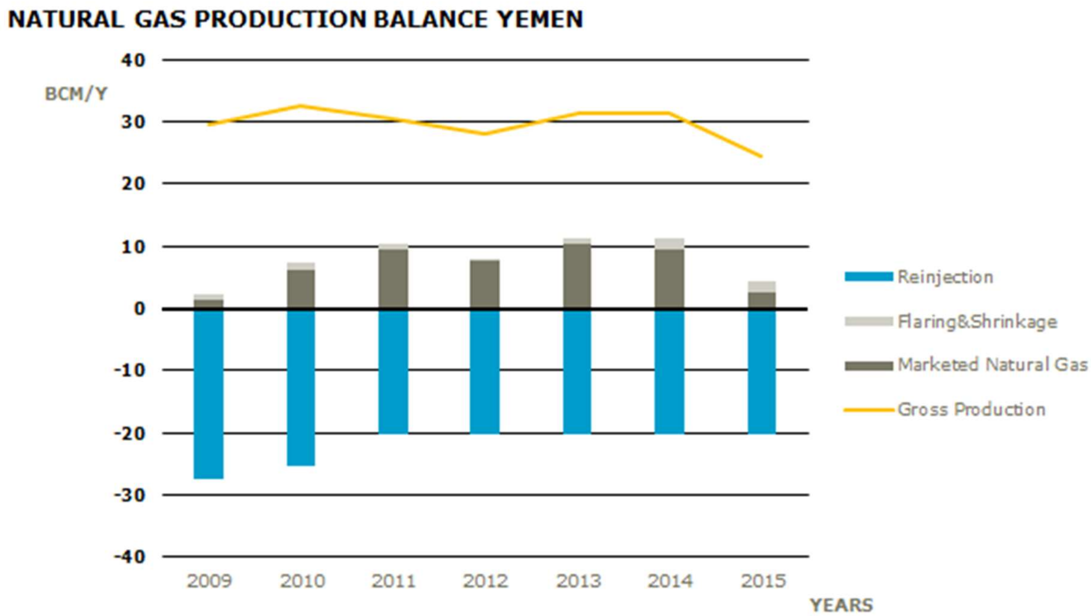


Source: Yemen LNG & Ministry of Oil and Minerals.

The availability of the uncommitted reserves is not known. However the owners of the LNG export facility have an inherent incentive not to share their gas with projects developing the domestic gas market. In April 2015, Yemen declared force majeure on its LNG exports due to the civil war in the country and oil and production has halted.

Several attempts have been made to transport the gas from the Marib field to the coastal cities; however geography is challenging with mountains up to 2,000 meters to be crossed. Below in Figure 130 it is seen that large amounts of gas are reinjected, most likely in order to keep the oil production and export at reasonable levels. The vast majority of the gas, as explained above, is dedicated to Yemen LNG and only minor amounts benefit the population.

Figure 130: Natural Gas Production Balance Yemen

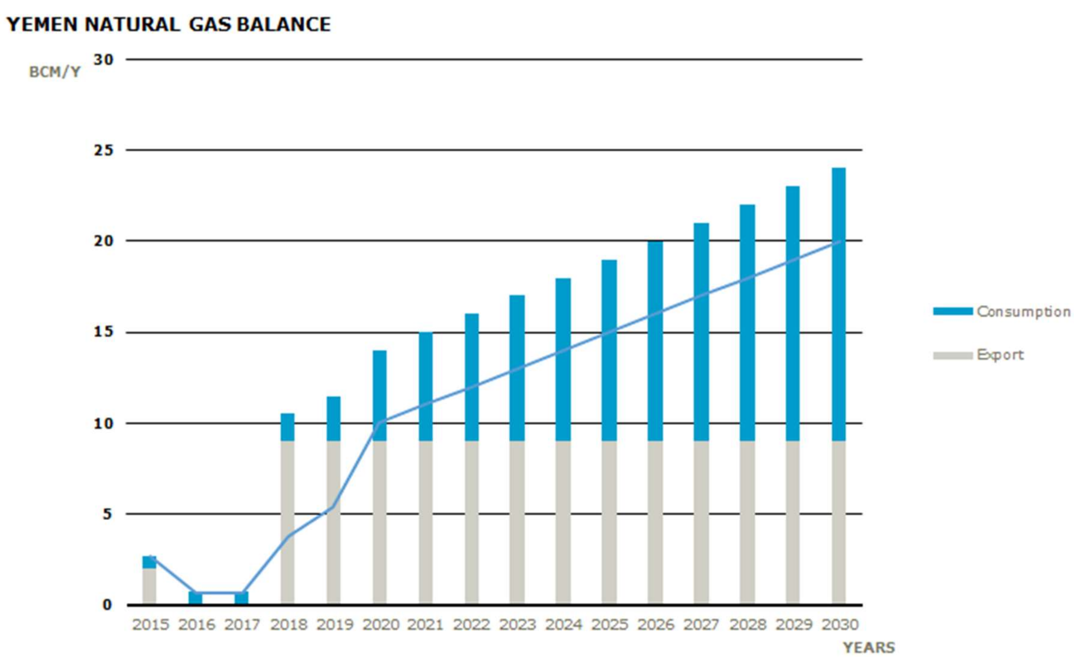


Source: OAPEC

10.25.2 Gas Demand

It is the priority of the government to use gas in the power sector, so far with little success. Gas can be used in many other aspects of daily life and if made available, consumption would surely grow fast in industry as well. Power sector modelling yields around 1 bcm of demand in the power sector. However, if security and stability is obtained we would expect total demand to increase up to 15 bcm a year in 2030. Under this assumption it is clear that a gas deficit is realised.

10.25.3 Gas balance



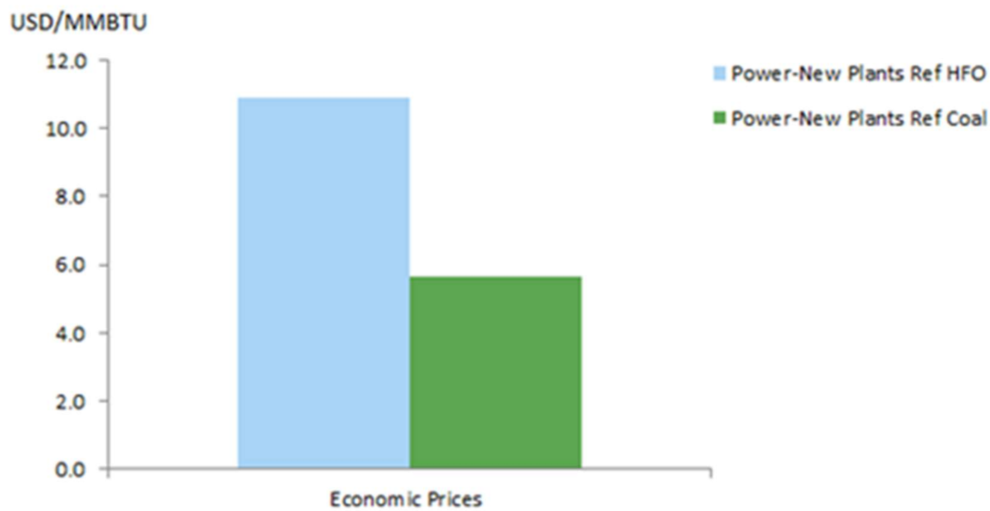
Source: Ramboll

10.25.4 Valuation of gas and gas supply pricing

10.25.4.1 Supply of gas – LRMC

Long run marginal costs are not developed for Yemen but the reserves are not difficult to produce it is more a question of bringing it to the market which could easily cost 2-3 USD/MMBTU.

10.25.4.2 Internal valuation of gas



Source: Ramboll

10.25.5 Subsidies

Box 16 illustrates Yemen’s failed reform efforts.

Box 16: Yemens failed reform efforts

Yemen illustrates a case of largely failed domestic pricing reform efforts over several years. By the end of the 2000s, subsidies for liquid fuels, LPG, and electricity had usurped around a third of state spending, more than the country's combined spending on health and education. Yemen's subsidies overwhelmingly benefited the country's urban upper and middle classes; they have access to transport, energy, and infrastructure links. Around half the country (primarily the former South and the geographically remote provinces across Yemen's northern borders) lacks infrastructure, formal price-controlled markets, and the ability to access the country's electricity grid. Yemen's severely deteriorating domestic security situation since the early 2010s, prior to and following the onset of the Arab Spring, has led to a further deterioration of its finances. An increasing number of attacks on its oil and gas infrastructure has reduced the country's hydrocarbon exports, adding to pre-existing domestic fuel shortages.

Having had to import rising volumes of fuel products to cover shortfalls in domestic production, fiscal pressure on Yemen reached unprecedented levels; in a hasty and ill-prepared reform effort in July 2014, the country was forced (under intense pressures from international lenders) to raise domestic energy prices. Amidst political turmoil, daily demonstrations in the streets of Sanaa, and continued violent conflict between tribal groups and the central government in several provinces (many of which remain isolated from any electricity or fuel supply), the government's decision to raise domestic energy prices was seen as a further failure by the state to provide for its citizens. Yemen's weak central state has subsequently been unable to withstand pressure from non-state groups – notably the Houthis – for a swift reversal of initial reform efforts. This underlines the difficulty, if not impossibility, of reforming energy pricing once states have failed fiscally and politically, and credibility has collapsed.

Source: OIES: A Brief Political Economy of Energy Subsidies in the Middle East and North Africa. 2015

APPENDIX 1 TRANSPORT COST COMPARISON PIPELINES VS LNG

10.26 **Transport cost comparison Pipelines vs. LNG**

The traditional belief in the industry has been that transport of LNG was cheaper when transporting large volumes over long distances.

In the following, a number of cases will be presented to compare transport costs per MMBTU related to gas transport via on-shore pipeline with LNG solution. Based upon assumptions drawn on public and Ramboll's internal data, the comparison addresses indicative price estimates to evaluate orders of magnitude in transport price differences offered by nowadays gas transport solutions. Despite being distinctive influential factors to cater to gas demand in the market, the quality and composition of gas delivered by pipelines and LNG delivery, , has not been accounted for.

The base case scenario entails a comparison between a 56" pipeline and equivalent transport by a 160,000 cbm LNG carrier. To illustrate differences in costs of various pipeline sizes, we add 24", 36", 48'' as well for illustrational and comparison purposes.

The LNG case features an FSRU and the sunk cost of liquefaction

10.27 **Basecase**

In the base case scenario a comparison between an estimate of gas transportation cost via a 56'' pipeline and a 160.000 cbm tanker as a function of distance from gas resource to market is performed. For the sake of comparison, 24'', 36'' and 48'' pipelines will also be illustrated and compared to LNG transport solutions via a 160.000 cbm tanker.

10.28 **Assumptions**

The assessment hinges on the following assumptions drawn from our previous experience:

As far as technical features of the 56'' pipeline system are concerned, the following set of assumptions has been considered:

- The pipeline outer diameter is equal to 56'' inches with a 20 mm wall thickness
- Entry-point pressure of 100 barg and end-point pressure of 75 barg.

- To compensate for the pressure drop along the pipeline, compression stations with a compression ratio of 1.3 and requiring a nominal power of 29 MW have been installed every 300 Km long pipeline segment.
- 2 x 100% back-up compressor per station
- Compression stations are assumed to be powered by 50 MW combined-cycle gas turbine stations with a nominal efficiency of 60%, fuelled by approximately 33 Mil.m3 gas per year (approx. 0.15% of the pipeline maximum throughput).
- The gas pipeline system load factor is 85% of the maximum throughput (approximately 21.6 bcm/year)

As to the pipeline CAPEX estimate, the following cost assumptions are made:

- Estimated unit price are derived from 2013 nominal price estimates made for the Trans Saharan gas pipeline feasibility study (2013EU average inflation rate considered is1.7%).
- The estimated unit price considered in the assessment are nominal prices compounded to 2015 with an assumed yearly interest rate of 7% pipeline overall construction and installation cost is assumed to be 1 USDm per Km pipeline.
- Compressor construction and installation cost is assumed to be 4.5 USDm per MW installed power capacity
- Project life time equal to 30 years
- Interest rate for calculating the annual worth value equal to 7%

The OPEX estimate has been computed assuming that:

- The yearly OPEX of the pipeline is about 2.6% of its CAPEX (i.e. 58,000 m per year per Km pipeline)
- The yearly OPEX of a compression station is about 2.6% of its CAPEX (i.e. 4.2 USDm per year)
- The yearly gas consumed by the compression station amounts to 6.2 USDm considering a wholesale gas price of 5 USD per MMBTU (~190 USD/1000cbm).
- The cost of steel for line pipe cost estimate is circa 1USD per Kg

The yearly transport cost for LNG via a 160,000 cbm tanker has been estimated based on these assumptions:

- Day rate for shipping amounts to USD 100,000 (high-end average spot market price due to the introduction of new fleets)
- Average navigation speed 15 knots
- HFO and MDO fuel prices equal to USD300 and USD900 respectively
- Daily boil-off is 0.14% (~232 cbm of LNG)
- Vessel filling ratio of 98.5%
- The days account for days of voyage, for a round-trip

Based on the described assumptions, the pipeline total yearly cost per 300 Km long segment, which also includes the cost related to a compression station and related fuel cost for power generation via combined cycle gas turbine , has been estimated to be 31.6 USDm per 100 Km pipeline long segment (CAPEX and OPEX shares are respectively 71% and 29%).

In transport of gas via LNG, expenditures related to the LNG value chain have been accounted for. These relate to CAPEX and OPEX of the liquefaction and regasification infrastructures.

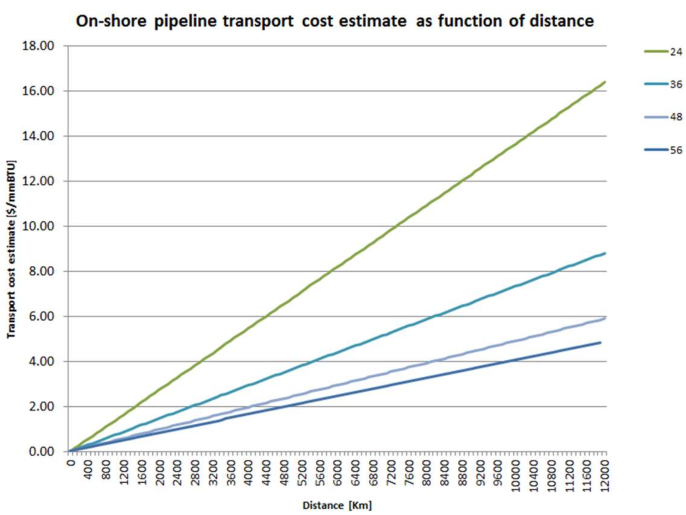
Estimates for these values have been made drawing upon cost estimate observations regarding brownfield expansion and greenfield plant projects executed in the US and in Australia[79].

For the purpose of the assessment, we assumed a liquefaction cost of 3.0 USD and 4.0 USD per MMBTU as for brownfield expansion and greenfield plan projects respectively, and a regasification cost of 0.5 USD per MMBTU.

10.29 **Results**

As outlined in Figure 131, it is evident that average gas transport cost of on-shore pipeline is a function of its dimension. Bearing in mind that pipeline yearly capacity is approximately direct proportional to the pipeline diameter by the power of 2.5, the rapid cost decline is justified.
In reality, due to economy of scale, a slight reduction in transport price may be expected and justifiable once very long distances are considered. Hence trends of transport costs tend to bend to lower values than those represented in the figure for considerate distances.

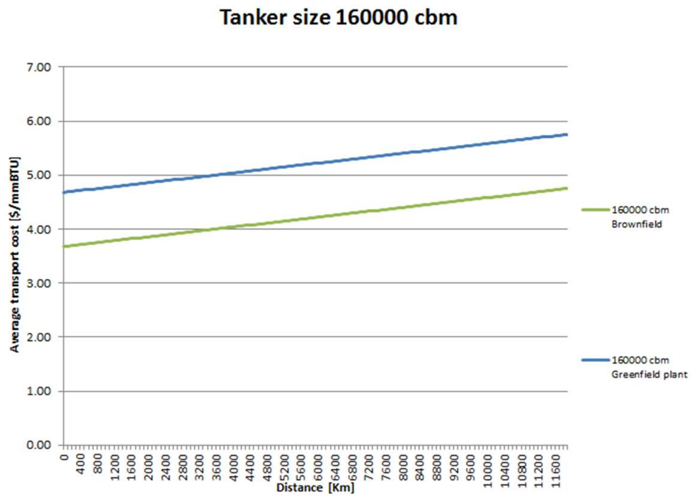
Figure 131: On-shore pipeline transport cost estimate



When considering gas transport via LNG solutions, the average transport cost features a distance-independent component, which covers the costs associated with liquefaction and regasification capital and operational costs, and a distance-dependent component. This latter is a function of the vessel delivery characteristics (i.e. speed, days at sea and in port), fuel price, and charter rates established daily in a volatile market or agreed upon long term contracts.
Figure 132 emphasises these main two components of LNG transport solution cost assuming a daily rate of USD 100,000.

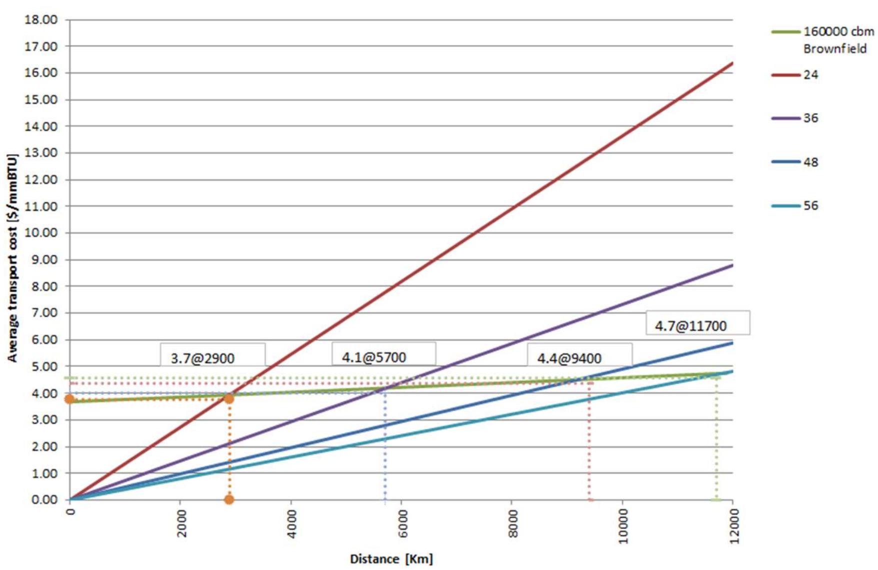
[79] "LNG markets in transition: the great reconfiguration", Anne-Sophie Corbeau and David Ledesma, Oxford University Press, 2016

Figure 132: Average transport cost for an LNG solution using a 160.000 cbm tanker assuming a daily rate of USD 100,000



With a view to attempting a like-for-like comparison of gas transport via on-shore pipeline and LNG systems, Figure 133 presents a superposition of the estimated transport cost expressed in USD per MMBTU of gas.

Figure 133: On-shore pipeline and LNG transport (regasification + liquefaction included in as to brownfield expansion projects) cost in comparison



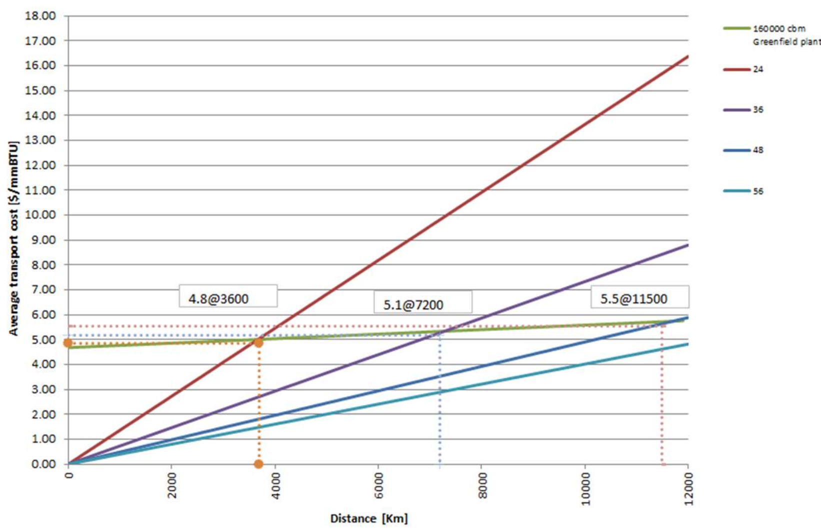
It is worth noticing that:

- For distances below 2900 Km, the regasification and liquefaction cost of 3.5 USD/MMBTU are not offset by a lower transport cost per 100 Km distance than the pipeline solution's associated transport cost.
- Above 2900 Km the LNG solution is economically viable compared to the 24'' pipeline system solution
- At a distance of 5700 Km, LNG solution becomes economically competitive with the 36'' pipeline solution
- At a distance of 9400 Km, LNG solution becomes economically competitive with the 48'' pipeline solution

- At a distance of 11700 Km, LNG solution becomes economically competitive with the 56'' pipeline solution

In case of greenfield plan projects, the average capital cost related to them would be assumed to be 20% higher than previously Hence LNG solutions become uncompetitive with 56'' diameter pipelinesfor distances below 12,000 km.

Figure 134: On-shore pipeline and LNG transport (regasification + liquefaction included in as to greenfield plan projects) cost in comparison



In conclusion:

Liquefaction CAPEX and OPEX distance-independent cost reduction represents the key factor which makes LNG solutions economically competitive to pipeline solutions

Increase or decrease of LNG transmission costs per Km depends on daily charter rates established in the spot tanker market. Its volatility is a function of many different factors; to name but a few, these may be LNG demand for security of supply (e.g. Fukushima 2011 nuclear power plant impact), recouping of financial investment for building new vessel fleets, newly introduced technology for vessels' engines (i.e. duel fuel diesel-electric vessels DFDE, or TFDE triple fuel diesel electric vessels), and oil and gas arbitrage.

Sensitive to the above mentioned aspects, ship daily rates can span from USD 60,000 to 160,000 per MMBTU depending on the markets. In accordance to this, distances at which LNG become competitive with on-shore pipeline transmission will be subject to spot market price oscillation, unless price hedging measures through long/medium term agreements are established between the different players along the LNG value chain.

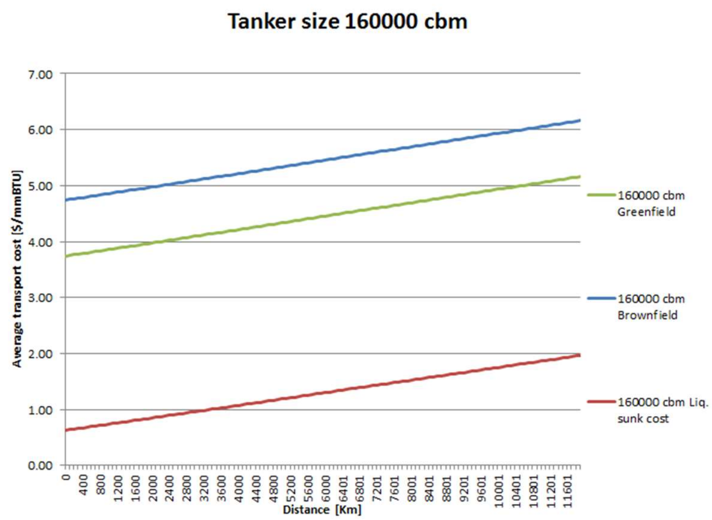
10.30 **LNG case FSRU + sunk cost of liquefaction**

Over the last 10 years, the utilization of floating storage and regasification units (FSRU) have been being increasingly employed in smaller emerging markets to cater for emergency of supply and seasonal gas demands. The advantage of this technology lies in faster construction time, and lower investment cost than its land-based facility counterpart In this assessment we suppose that the CAPEX and OPEX cost related to the liquefaction is about 0.4 USDm per MMBTU (about 20% lower than for the previous case).

Moreover, we assume that costs related to the CAPEX of the liquefaction facility are considered as sunk costs amortised and incurred by gas liquefaction companies as expenses of previous infrastructure investments. Joint Venture (JV) type of agreements between liquefaction, charter party and regasification players could justify such a reality.

Alternatively, almost-extinguished financing of newly built liquefaction facilities may be suitable cases to consider CAPEX as sunk expenditures (e.g. Qatargas). As Figure 135 stresses out, this situation allows for a net reduction of the distance-independent cost part of the average LNG transmission cost.

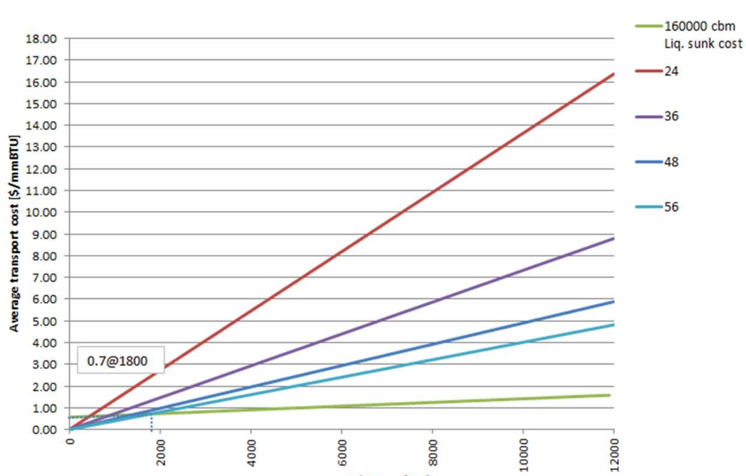
Figure 135: On-shore pipeline and LNG transport (regasification + liquefaction included in as to brownfield expansion projects) cost in comparison



Under these hypotheses and for short distances pipeline transmission costs are slightly more competitive than LNG at a transmission price level of 0.7 USD per MMBTU regardless of the pipeline capacity.

For distances above 2,000 Km and up to 12,000 Km, with liquefaction costs curtailed, LNG transmission prices are in net competitive advantage than any pipeline capacity and offer a remarkable price range spanning between 0.7 to 1.6 USD per MMBTU.

Figure 136: On-shore pipeline and LNG transport with liquefaction sunk costs (regasification at 0.4 USD per MMBTU and 100,000 USD tanker daily rate) comparison of transport costs



In summary, the following can be inferred:

LNG gains have competitive appeal only if CAPEX for liquefaction facilities have either been previously incurred or nearly fully recouped in their financing process.

Variation of fuel prices (HFO and MDO) and daily ship rate due to a newly introduced fleet; the capital investments incurred in shipbuilding agreements introduce fluctuations in the tanker market.

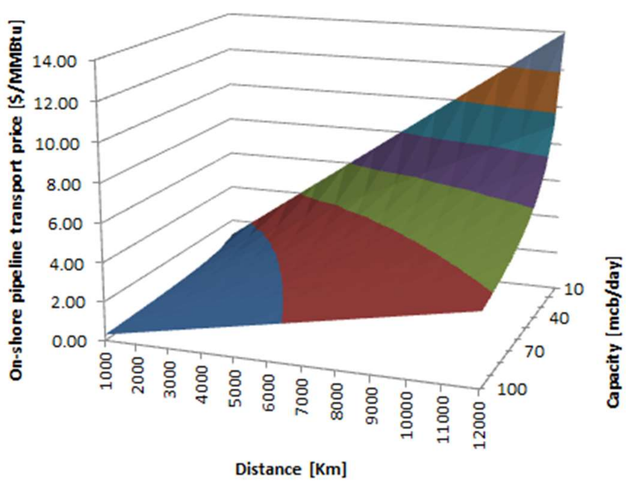
The sensitivity of LNG transmission costs to volatile daily tanker market rates, assuming a variation between USD 50,000 to 150,000, delineates a range of distances around 1,800 Km at which LNG becomes more competitive than the 56''pipeline solution.

In the long term, daily rate prices will reflect the amount of debt to be recouped by the investors given the financing of capital investment to build new fleets.

10.31 **Price comparison and conclusion**

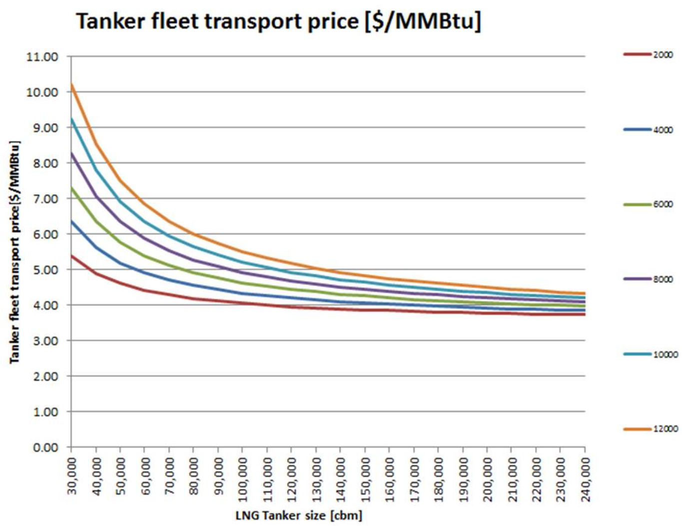
Bearing in mind these assumptions, Figure 137 outlines as pipeline transport prices increasing linearly with distance and decreasing approximately as the inverse of the square root of the pipeline capacity.

Figure 137: Onshore pipeline system estimated transportation cost as function of distance and capacity



As for green and brown field projects, tanker fleet LNG transport prices (including liquefaction and regasification costs) for a fixed daily rate of USD100,000 decrease with the increase of tanker size. Figure 138 shows how price variation becomes less sensitive to distance as the tanker size approaches 120000-130000 cbm.

Figure 138: Tanker fleet transport prices as function of Tanker size and distance covered for a daily rate of USD 100,000



In particular, the 160000 cbm tanker, the object of the base case scenario, presents a price increase of USD1 when distance increments from 1000 to 12000 Km. Hence, the LNG transport mechanism becomes increasingly more competitive as tanker size increases.

Gas transport via pipeline and LNG, despite differing as transport mechanisms, can in principle be compared on the basis of the cost per MMBTU of the transported medium. If the comparison is extended to capacity in terms of mcm of gas per day, transport prices per MMBTU via LNG can be deemed constant with capacity, being this value merely dependent on the number of tankers employed in the fleet once their size has been selected.

With the intent on pursuing a comparison between the level of price competitiveness of these gas transport systems, 160,000 cbm LNG associated transport prices per MMBTU are subtracted from off-shore and on-shore pipeline related ones. The green areas outline capacity values and distances for which LNG transport prices are higher than the pipelines' associated ones. As for the green field case the comparison follows.

Table 38: 160000 cbm LNG (Greenfield project) and Onshore transport price comparison

Mm3/day	LNG - Onshore pipeline transport price comparison [$/MMBtu] Distance [Km]											
	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
100	4.45	4.23	4.00	3.78	3.56	3.34	3.12	2.90	2.68	2.46	2.24	2.02
90	4.43	4.19	3.95	3.71	3.47	3.23	2.99	2.75	2.51	2.27	2.03	1.79
80	4.41	4.14	3.88	3.61	3.35	3.09	2.83	2.56	2.30	2.03	1.77	1.51
70	4.38	4.09	3.79	3.50	3.21	2.92	2.63	2.34	2.04	1.75	1.46	1.17
60	4.34	4.01	3.69	3.36	3.03	2.71	2.38	2.05	1.73	1.40	1.07	0.75
50	4.30	3.92	3.55	3.18	2.80	2.43	2.06	1.69	1.31	0.94	0.57	0.20
40	4.23	3.80	3.36	2.92	2.49	2.05	1.62	1.18	0.74	0.31	-0.13	-0.56
30	4.14	3.61	3.08	2.55	2.02	1.49	0.96	0.43	-0.10	-0.63	-1.16	-1.69
20	3.98	3.28	2.59	1.90	1.21	0.51	-0.18	-0.87	-1.57	-2.26	-2.95	-3.64
10	3.59	2.52	1.44	0.37	-0.70	-1.78	-2.85	-3.93	-5.00	-6.08	-7.15	-8.22

Table 38 shows that greenfield LNG system' competitiveness increases as the capacity decreases and distance increases. In case of brown field projects, lower liquefaction costs enhance LNG competition for higher capacity values than previously.

Table 39: 160000 cbm (Brownfield project) LNG and Onshore transport price comparison

Mm3/day	LNG - Onshore pipeline transport price comparison [$/MMBtu] Distance [Km]											
	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
100	3.45	3.23	3.00	2.78	2.56	2.34	2.12	1.90	1.68	1.46	1.24	1.02
90	3.43	3.19	2.95	2.71	2.47	2.23	1.99	1.75	1.51	1.27	1.03	0.79
80	3.41	3.14	2.88	2.61	2.35	2.09	1.83	1.56	1.30	1.03	0.77	0.51
70	3.38	3.09	2.79	2.50	2.21	1.92	1.63	1.34	1.04	0.75	0.46	0.17
60	3.34	3.01	2.69	2.36	2.03	1.71	1.38	1.05	0.73	0.40	0.07	-0.25
50	3.30	2.92	2.55	2.18	1.80	1.43	1.06	0.69	0.31	-0.06	-0.43	-0.80
40	3.23	2.80	2.36	1.92	1.49	1.05	0.62	0.18	-0.26	-0.69	-1.13	-1.56
30	3.14	2.61	2.08	1.55	1.02	0.49	-0.04	-0.57	-1.10	-1.63	-2.16	-2.69
20	2.98	2.28	1.59	0.90	0.21	-0.49	-1.18	-1.87	-2.57	-3.26	-3.95	-4.64
10	2.59	1.52	0.44	-0.63	-1.70	-2.78	-3.85	-4.93	-6.00	-7.08	-8.15	-9.22

If liquefaction costs are treated as sunk costs, LNG transport turn into a viable solution which may be able to outstrip pipelines in the gas transport competition.

Table 40: 160000 cbm LNG (Liquefaction sunk price) and Onshore transport price comparison

Mm3/day	LNG - Onshore pipeline transport price comparison [$/MMBtu] Distance [Km]											
	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
100	0.35	0.13	-0.10	-0.32	-0.54	-0.76	-0.98	-1.20	-1.42	-1.64	-1.86	-2.08
90	0.33	0.09	-0.15	-0.39	-0.63	-0.87	-1.11	-1.35	-1.59	-1.83	-2.07	-2.31
80	0.31	0.04	-0.22	-0.49	-0.75	-1.01	-1.27	-1.54	-1.80	-2.07	-2.33	-2.59
70	0.28	-0.01	-0.31	-0.60	-0.89	-1.18	-1.47	-1.76	-2.06	-2.35	-2.64	-2.93
60	0.24	-0.09	-0.41	-0.74	-1.07	-1.39	-1.72	-2.05	-2.37	-2.70	-3.03	-3.35
50	0.20	-0.18	-0.55	-0.92	-1.30	-1.67	-2.04	-2.41	-2.79	-3.16	-3.53	-3.90
40	0.13	-0.30	-0.74	-1.18	-1.61	-2.05	-2.48	-2.92	-3.36	-3.79	-4.23	-4.66
30	0.04	-0.49	-1.02	-1.55	-2.08	-2.61	-3.14	-3.67	-4.20	-4.73	-5.26	-5.79
20	-0.12	-0.82	-1.51	-2.20	-2.89	-3.59	-4.28	-4.97	-5.67	-6.36	-7.05	-7.74
10	-0.51	-1.58	-2.66	-3.73	-4.80	-5.88	-6.95	-8.03	-9.10	-10.18	-11.25	-12.32

In a glutted market, low gas prices intensify competition towards low transport price solutions. Pipelines still represent the most feasible gas transport system in the long term, although construction of larger and cheaper tankers due to economics of scale, and the establishment of commercial agreements between different players along the LNG value chain, aiming at lowering the impact of liquefaction costs over transport prices, will increase LNG competition.

In the short run, however, leveraging on shorter construction and installation time for liquefaction and regasification facilities, LNG transport mechanism may be able to outweigh pipelines solutions for scenarios in which geopolitical or market barriers hinder the access to new and small markets, where security of supply and diversification of gas players are key factors to guarantee fairer local gas prices.

10.32 **Feasibility of export of LNG**

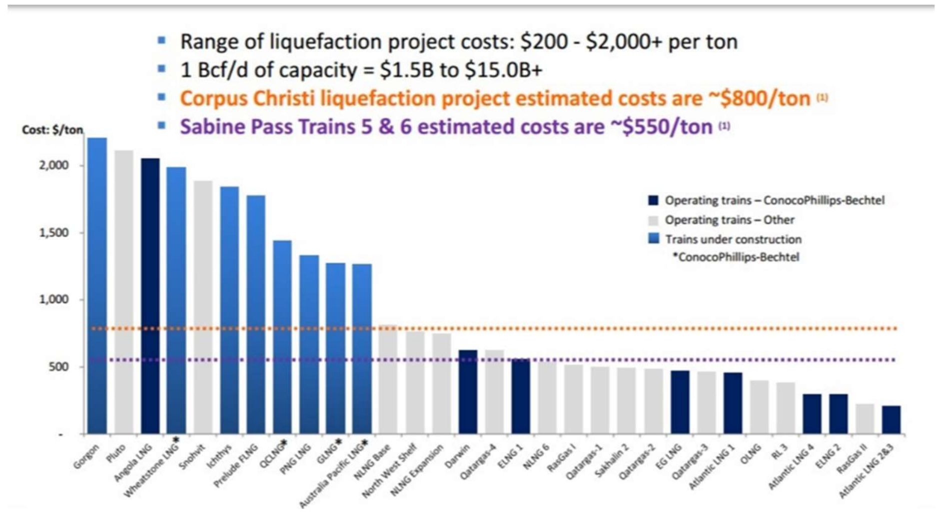
10.32.1 Incentives for new LNG export facilities

In the following we argue that the incentive to pursue monetization of the gas through new LNG export facilities currently is absent also taking into account future potential increasing gas prices.

10.32.1.1 Liquefaction costs

Liquefaction costs are highly dependent on the commodity prices of the day as well as location of the LNG facility. Many MENA countries have good existing infrastructure and would therefore not be as expensive as more isolated liquefaction plants such as Gorgon, Angola or PNG.

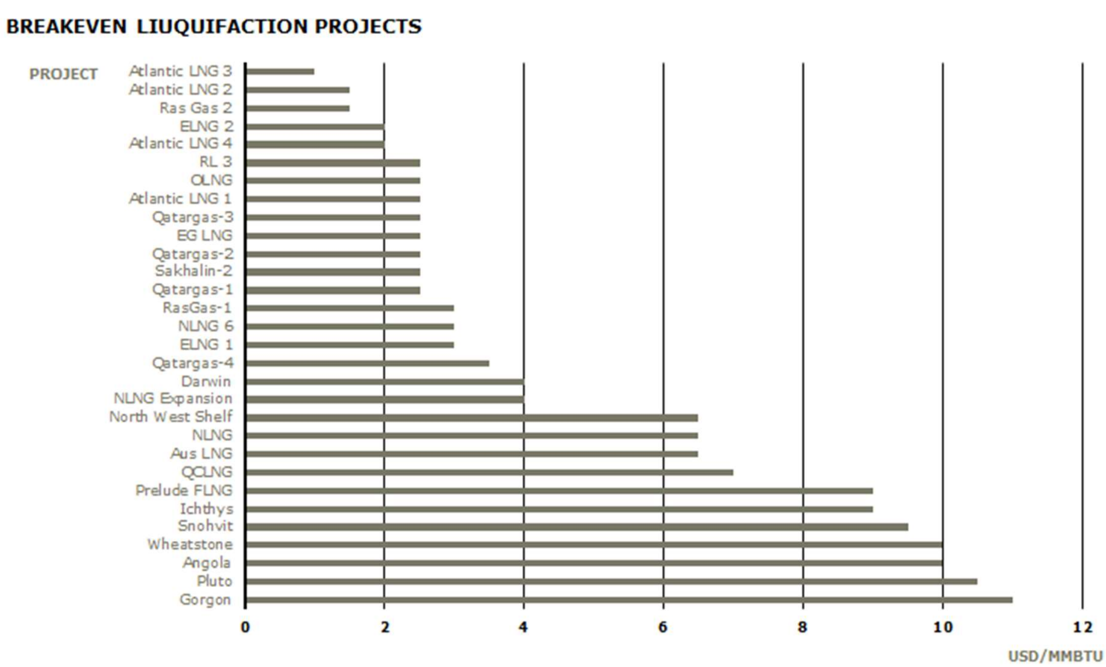
Figure 139 Liquefaction Costs



. Source: Cheniere Energy based on Wood Mackenzie; Project costs reflect the liquefaction facility's capex in dollars per ton. Chart includes a representative sample of brownfield and greenfield liquefaction facilities and does not include all liquefaction facilities existing or under construction. It looks like the timing of the construction of these project stretches over 20+ years, which explains the right side of the graph.

As Figure 139 shows, the range of costs is very broad, with recent projects being more expensive than older projects. Cheniere energy has lower costs as it is located in USA and is a modification of a regasification plant. . Figure 140 converts data into cost per MMBTU, which illustrates that there is a potential to understate or underestimate the "high side" of liquefaction costs. Projects were started before the fall in oil and gas prices in 2014 which may explain the high costs.

Figure 140 Liquefaction Costs converted to MMBTU



Source: Cheniere, OIES, Ramboll

Sabine Pass 1-4 is a reworking of an existing regasification plant to an export facility, so it is much cheaper than a new-build LNG export terminal such as Corpus Christi 1-2. Sabine 5-6 and Corpus Christi 3 are expansions of existing facility and are therefore cheap. All of these are based in industrialised areas of the US with cheap capital, developed infrastructure and availability of labour and manufacturing, and therefore likely to be cheaper than liquefaction facilities abroad.

Oxford Energy Institute attempts to estimate these costs using public data and shows a split between USD2.75 and USD4.5 per MMBTU. We suggest that Arab countries have reasonable infrastructure and access to workers and manufacturers and new LNG projects can therefore be classified as "Greenfield Normal" with a cost of USD3.5 per MMBTU

Table 41 Liquefaction Costs. Oxford Energy Institute "LNG Markets in Transition" and Cheniere Presentation (1 mcf = c.1 MMBTU)

	Liquefaction Costs	CAPEX $m/mpta	OPEX $/mcf	Years	Breakeven $/mcf
1	OEI Brownfield Normal	700	1.00	30	2.75
2	OEI Brownfield High	1100	1.20	30	4.00
3	OEI Greenfield Normal	900	1.00	30	3.50
4	OEI Greenfield High	1600	1.20	30	4.50
1	Sabine Pass T1-4	667	1.00	30	2.75
2	Corpus Christi 1-2	1111	1.00	30	4.00
3	Sabine Pass T5-6	667	1.00	30	2.75
4	Corpus Christi 3	667	1.00	30	2.75

10.32.1.2 Production + liquefaction costs:

The above numbers for upstream and liquefaction and the European gas price in minus USD1 for transportation and regasification, illustrates that even the cheapest upstream field with brownfield liquefaction option in a low CAPEX environment does not reach an IRR of above 11% which is already a low estimate of the IRR requirements. This suggests that higher prices would be necessary to justify the construction of new greenfield regional LNG export projects.

Table 42: IRR of different Field/Liquefaction combinations.

IRR		Field			
		Zohr	Leviathan	Tamar	Petroceltic
LNG Option	OEI Brownfield Normal	8%	11%	10%	5%
	OEI Brownfield High	5%	8%	7%	2%
	OEI Greenfield Normal	7%	10%	9%	4%
	OEI Greenfield High	3%	6%	5%	0%

APPENDIX 2 – REFERENCE LIST FIELD ANALYSIS

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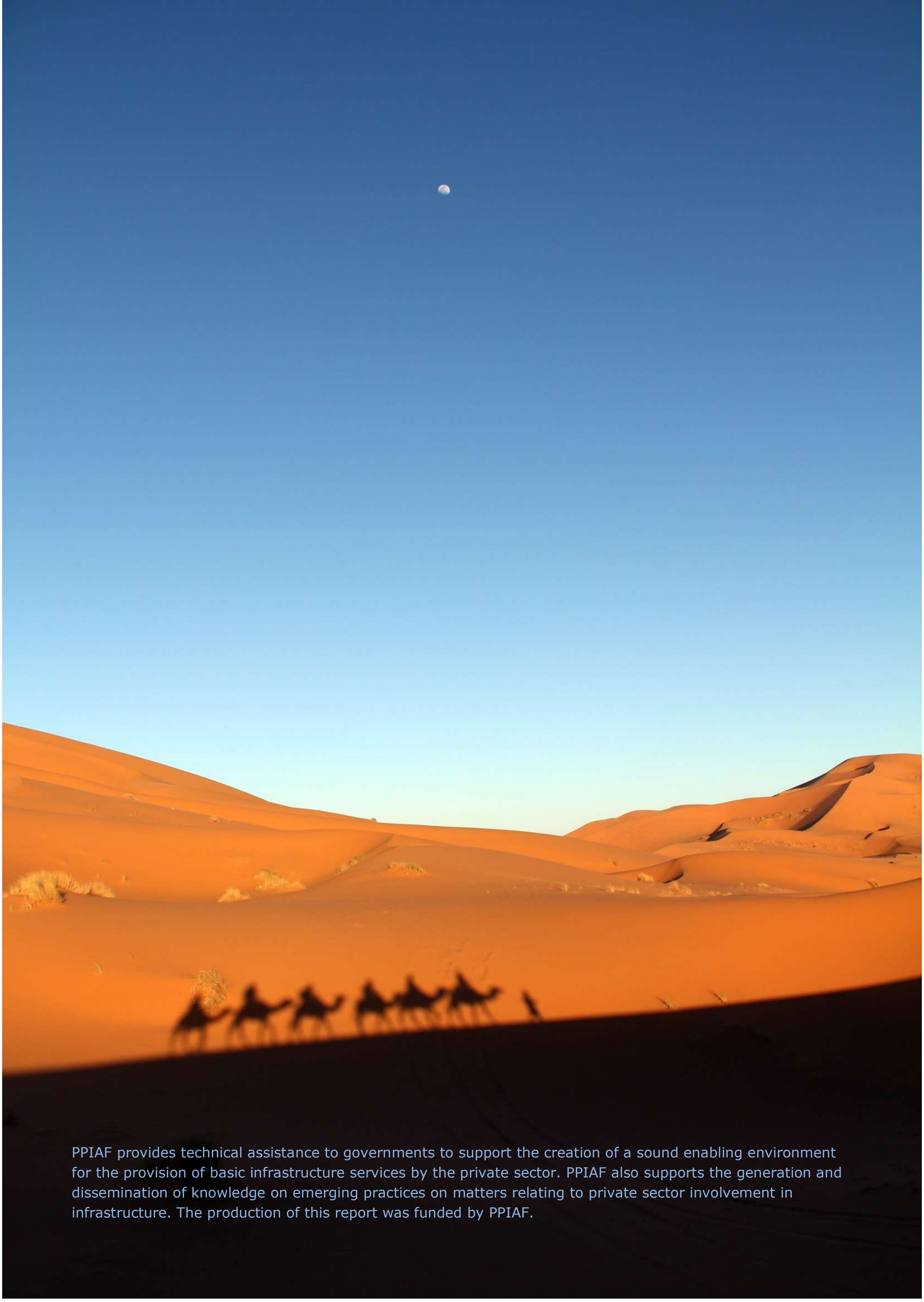

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